Table of Contents

Title 43
NATURAL RESOURCES

Part XIII. Office of Conservation—Pipeline Safety2

Table of Contents

Title 43
NATURAL RESOURCES
Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation—Pipeline Safety
Subpart 1. General Provisions

Chapter 1. General

§101. Applicability

A. This regulation shall apply to all persons engaged in the transportation of gas by pipeline within the state of Louisiana, including the transportation of gas within the coastal zone limits as defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

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

C. As to gas odorization, this regulation shall apply to all persons engaged in the business of handling, storing, selling, or distributing natural and other toxic or combustible odorless gases, except as hereinafter provided.

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

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

§103. Purpose

A. The purpose of these rules is to establish minimum requirements for the design, construction, quality of materials, location, testing, operation and maintenance of facilities used in the gathering, transmission and distribution of gas, to safeguard life or limb, health, property and public welfare and to provide that adequate service will be maintained by gas utilities operating under the jurisdiction of the commissioner of conservation.

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:217 (April 1983), amended LR 10:509 (July 1984), LR 30:1219 (June 2004).

§105. Incorporation by Reference

A. Any documents or portions thereof incorporated by reference in this Part are included in this Part as though set out in full. When only a portion of a document is referenced, the remainder is not incorporated in this Part.

B. To the extent consistent with this regulation, all persons shall be governed by the provisions of Parts 191, 192, 193, 199 and 40 of Part 49 of the *Code of Federal Regulations*, sometimes hereinafter referred to as the *Federal Code*, including all standards or specifications referenced therein, insofar as same are applicable and in effect on the date of this regulation, and by any deletions, additions, revisions, or amendments thereof, made after said date.

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:217 (April 1983), amended LR 10:509 (July 1984), LR 24:1306 (July 1998), LR 30:1219 (June 2004), LR 44:1032 (June 2018).

§107. Deviations from the Regulations

A. There shall be no deviation from Part XIII except after authorization by the commissioner. If hardship results from application of any provisions, rules, standards, and specifications herein prescribed because of special facts, application may be made to the commissioner to waive compliance with such regulation in accordance with Section 3(e) of the Natural Gas Pipeline Safety Act of 1968. Each request for such waiver shall be accompanied by a full and complete justification.

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:217 (April 1983), amended LR 10:509 (July 1984), LR 30:1220 (June 2004).

§109. Recommendation for Revision of Regulations

A. For the purpose of keeping the provisions, rules, standards, and specifications of this regulation effective, any persons subject to this regulation, either individually or collectively, shall file an application setting forth such recommended changes in rules, standards, or specifications as they deem necessary to keep this regulation effective in keeping with the purpose, scope, and intent thereof. However, nothing herein shall preclude other interested parties from initiating appropriate formal proceedings to have the commissioner of conservation consider any changes they deem appropriate, or the commissioner of conservation from acting upon his own motion.

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:217 (April 1983), amended LR 10:509 (July 1984), LR 30:1220 (June 2004).

§111. Records, Reports

A. All persons subject to this regulation shall maintain records, such as plans, programs, specifications, maps and permits, necessary to establish compliance with this regulation. Such records shall be available for inspection at all times by the commissioner.

B. Every person who engages in the sale or transportation of gas subject to the jurisdiction of the commissioner shall file with the commissioner a list including the names, addresses and telephone numbers of responsible officials or such persons who may be contacted in the event of an emergency. Such a list shall be kept current.

C. Notices, reports and plans pertinent to facilities covered by §101 of this regulation and which are submitted to the United States Department of Transportation pursuant to the provisions of the federal code shall be forwarded simultaneously to the commissioner. These filings shall be deemed in full compliance with all obligations imposed for submitting such notices and reports, and when accomplished, shall release and relieve the person making same from further responsibility therefor.

D. Where a person is required to prepare and submit a report of an accident or incident pertinent to facilities covered by §101 of this regulation to a federal agency in compliance with the outstanding order of such agency, a copy of such report shall be submitted to the commissioner in lieu of filing a similar report which may be required by the state.

E. To accomplish the purpose of Section 557(G) of the Act the commissioner may request the filing of additional information and reports upon such forms and in such manner as prescribed by him.

F. An updated and comprehensive system map(s) containing location and component description information on all facilities (excluding individual service lines), must be maintained by the operator and made available to the commissioner of conservation upon demand. An updated and comprehensive record of individual service lines containing location and component description information must be maintained by the operator and made available to the commissioner of conservation upon demand. The aforementioned maps and records must be accompanied by information showing the location, size and type of pipe, and locations of key valves (system isolation valves), regulator stations, odorization injection and test locations and cathodic protection test locations.

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 30:1220 (June 2004).

Subpart 2. Transportation of Natural Gas and Other Gas by Pipeline [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 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). [49 CFR 191.1(a)]

B. This Chapter does not apply to: [49 CFR 191.1(b)]

1. offshore gathering of gas in state waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream; [49 CFR 191.1(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 [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)]

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).

§303. Definitions [49 CFR 191.3]

A. As used in Part XIII and in the PHMSA Forms referenced in this Part [49 CFR 191.3]:

Administrator—the administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Commissioner—the Commissioner of Conservation or any person to whom he has delegated authority in the matter concerned.

Confirmed Discovery—means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.

Gas—natural gas, flammable gas, or gas which is toxic or corrosive.

Incident—any of the following events:

a. an event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

i. a death, or personal injury necessitating in-patient hospitalization;

ii. estimated property damage of $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in Chapter 4, Appendix A to Subpart 2.

iii. unintentional estimated gas loss of three million cubic feet or more;

b. an event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident;

c. an event that is significant in the judgment of the operator, even though it did not meet the criteria of Subparagraphs a or b of this definition.

LNG Facility—a liquefied natural gas facility as defined in §193.2007 of Part 193 of the federal pipeline safety regulations.

Master Meter System—a pipeline system for distributing gas within, but not limited to, a definable area such as a mobile home park, housing project, apartment complex or university, where the operator purchases meter gas from an outside source for resale through a gas pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as rents.

Municipality—a city, parish, or any other political subdivision of a state.

Offshore—beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator—a person who engages in the transportation of gas.

Person—any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

Pipeline or Pipeline System—all parts of those physical facilities through which gas moves in transportation, including but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery station, holders, and fabricated assemblies.

State—the state of Louisiana.

Transportation of Gas—the gathering, transmission, or distribution of gas by pipeline, or the storage of gas, in or affecting intrastate, interstate or foreign commerce.

Underground Natural Gas Storage Facility—means an underground natural gas storage facility as defined in §503 of this Chapter.

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).

§305. Telephonic Notice of Certain Incidents [49 CFR 191.5]

A. At the earliest practicable moment, within one hour after confirmed discovery, each operator shall give notice in accordance with Subsection B of this Section of each incident as defined in §303. [49 CFR191.5(a)]

B. Each notice required by Subsection A of this Section must be made to the National Response Center either by telephone to (800) 424- 8802 (in Washington, DC, 202 267-2675) or electronically at http:// www.nrc.uscg.mil and by telephone to the state of Louisiana to (225) 342-5505 and must include the following information: [49 CFR 191.5(b)]

1. names of operator and person making report and their telephone numbers; [49 CFR 191.5(b)(1)]

2. the location of the incident; [49 CFR 191.5(b)(2)]

3. the time of the incident; [49 CFR 191.5(b)(3)]

4. the number of fatalities and personal injuries, if any; [49 CFR 191.5(b)(4)]

5. all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. [49 CFR 191.5(b)(5)]

C. Within 48 hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in Subsection B of this Section with an estimate of the amount of product released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report. [49 CFR191.5(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 9:218 (April 1983), amended LR 10:510 (July 1984), LR 11:255 (March 1985), LR 20:442 (April 1994), LR 30:1221 (June 2004), LR 38:110 (January 2012), LR 44:1032 (June 2018), LR 45:66 (January 2019).

§307. Report Submission Requirements [49 CFR 191.7]

A. General. Except as provided in Subsection B and Subsection E of this Section, an operator must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at http://portal.phmsa.dot.gov/pipeline unless an alternative reporting method is authorized in accordance with Subsection D of this Section. [49 CFR 191.7(a)]

1. Each report required by §307.A, for intrastate facilities subject to the jurisdiction of the Office of Conservation, must also be submitted to Office of Conservation, P.O. Box 94275, Baton Rouge, LA 70804-9275 or may be transmitted by electronic mail to PipelineInspectors@la.gov.

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

B. Exceptions. An operator is not required to submit a safety-related condition report (§325) electronically. [49 CFR 191.7(b)]

C. Safety-Related Conditions. An operator must submit concurrently to the applicable State agency a safety-related condition report required by §323 for intrastate pipeline transportation or when the State agency acts as an agent of the secretary with respect to interstate transmission facilities. [49 CFR 191.7(c)]

D. Alternative Reporting Method. If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at (202) 366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received. [49 CFR 191.7(d)]

E. National Pipeline Mapping System (NPMS). An operator must provide the NPMS data to the address identified in the NPMS operator standards manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA geographic information systems manager at (202) 366-4595. [49 CFR 191.7(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).

§309. Distribution System: Incident Report [49 CFR 191.9]

A. Except as provided in Subsection C of this Section, each operator of a distribution pipeline system shall submit Department of Transportation Form RSPA F 7100.1 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §305. [49 CFR 191.9(a)]

B. When additional relevant information is obtained after the report is submitted under Subsection A of this Section, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report. [49 CFR 191.9(b)]

C. Master meter operators are not required to submit an incident report as required by this Section. [49 CFR 191.9(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 9:219 (April 1983), amended LR 10:510 (July 1984), LR 11:255 (March 1985), LR 30:1222 (June 2004), LR 38:111 (January 2012).

§311. Distribution System: Annual Report [49 CFR 191.11]

A. General. Except as provided in Subsection B of this Section, each operator of a distribution pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.1-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. [49 CFR 191.11(a)]

B. Not required. The annual report requirement in this Section does not apply to a master meter system, a petroleum gas system that serves fewer than 100 customers from a single source, or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in §508. [49 CFR 191.11(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 9:219 (April 1983), amended LR 10:511 (July 1984), LR 11:255 (March 1985), LR 30:1222 (June 2004), LR 38:111 (January 2012), LR 47:1140 (August 2021), repromulgated LR 47:1330 (September 2021).

§313. Distribution Systems Reporting Transmission Pipelines: Transmission or Gathering Systems Reporting Distribution Pipelines [49 CFR 191.13]

A. Each operator, primarily engaged in gas distribution, who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by §§315 and 317. Each operator, primarily engaged in gas transmission or gathering, who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by §§309 and 311. [49 CFR 191.13]

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).

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

A. 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)]

B. LNG. Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F 7100.3 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(b)]

C. Underground Natural Gas Storage Facility. Each operator of a UNGSF must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after the detection of an incident required to be reported under §505. [49 CFR 191.15(c)]

D. Supplemental Report. Where additional related information is obtained after an operator submits a report under Subsection A, B, or C of this Section, the operator must make a supplemental report as soon as practicable, with a clear reference by date to the original report. [49 CFR 191.15(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. 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)]

B. LNG. Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHMSA 7100.3-1 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(b)]

C. Underground Natural Gas Storage Facility. Each operator of a UNGSF must submit an annual report through DOT Form PHMSA 7100.4-1. This report must be submitted each year, no later than March 15, for the preceding calendar year. [49 CFR 191.17(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).

§321. OMB Control Number Assigned to Information Collection [49 CFR 191.21]

A. This Section displays the control number assigned by the Office of Management and Budget (OMB) to the information collection requirements in Chapter 3. The Paperwork Reduction Act requires agencies to display a current control number assigned by the Director of OMB for each agency information collection requirement. [49 CFR 191.21]

OMB Control Number 2137-0522	
Section of 49 CFR Part 191 Where Identified	**Form No.**
191.5	Telephonic
191.9	PHMSA7100.1, PHMSA7100.3
191.11	PHMSA7100.1-1, PHMSA7100.3-1
191.15	PHMSA7100.2, PHMSA7100.3
191.17	PHMSA7100.2-1, PHMSA7100.3-1, PHMSA7100.4-1.
191.22	PHMSA1000.1, PHMSA1000.2

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 11:256 (March 1985), amended LR 20:442 (April 1994), LR 30:1222 (June 2004), LR 38:112 (January 2012), LR 45:67 (January 2019).

§322. National Registry of Operators [49 CFR 191.22]

A. OPID Request. Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline, pipeline facility, or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must submit an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Operators in accordance with §307. For intrastate facilities subject to the jurisdiction of the Office of Conservation, the operator must concurrently file an online OR-1 Submission (Operator Registration) for Pipeline Safety with the same name as the OPID request at http://www.sonris.com. Each operator must validate the OR-1 annually by January 1 each year. [49 CFR 191.22(a)]

1. Each operator of a Special Class System must file an online OR-1 Submission (Operator Registration) for Pipeline Safety at http://www.sonris.com. Each Special Class System operator must validate the OR-1 annually by January 1 each year.

B. OPID Validation. An operator who has already been assigned one or more OPIDs by January 1, 2011, must validate the information associated with each OPID through the National Registry of Operators at https://portal.phmsa.dot.gov, and correct that information as necessary, no later than June 30, 2012. [49 CFR 191.22(b)]

C. Changes. Each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of Operators at https://portal.phmsa.dot.gov of certain events. For intrastate facilities subject to the jurisdiction of the Office of Conservation, a copy must also be submitted to Office of Conservation, P.O. Box 94275, Baton Rouge, LA 70804-9275 or by electronic mail to PipelineInspectors@la.gov. Any change in an operator name, the operator must concurrently file an online OR-1 Submission for Pipeline Safety with the same name as the OPID operator name at http://www.sonris.com/. [49 CFR 191.22(c)]

1. An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs: [49 CFR 191.22(c)(1)]

a. construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable; [49 CFR 191.22(c)(1)(i)]

b. construction of 10 or more miles of a new pipeline [49 CFR 191.22(c)(1)(ii)]

c. construction of a new LNG plant, LNG facility, or UNGSF; or [49 CFR 191.22(c)(1)(iii)]

d. maintenance of a UNGSF that involves the plugging or abandonment of a well, or that requires a workover rig and costs $200,000 or more for an individual well, including its wellhead. If 60-days' notice is not feasible due to an emergency, an operator must promptly respond to the emergency and notify PHMSA as soon as practicable; [49 CFR 191.22(c)(1)(iv)]

e. Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or [49 CFR 191.22(c)(1)(v)]

f. A pipeline converted for service under § 514 of this chapter, or a change in commodity as reported on the annual report as required by § 317. [49 CFR 191.22(c)(1)(vi)]

2. An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs: [49 CFR 191.22(c)(2)]

a. a change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs. [49 CFR 191.22(c)(2)(i)]

b. a change in the name of the operator; [49 CFR 191.22(c)(2)(ii)]

c. a change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, UNGSF, or LNG facility; [49 CFR 191.22(c)(2)(iii)]

d. the acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Subpart 3 of this Part; or [49 CFR 191.22(c)(2)(iv)]

e. the acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Subpart 3 of this Part; or [49 CFR 191.22(c)(2)(v)]

f. the acquisition or divestiture of an existing UNGSF, or an LNG plant or LNG facility subject to Subpart 5 of this Part. [49 CFR 191.22(c)(2)(vi)]

D. Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this Part and for submissions to the National Pipeline Mapping System. [49 CFR 191.22(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 38:112 (January 2012), amended LR 44:1032 (June 2018), LR 45:67 (January 2019), LR 46:1575 (November 2020), LR. 47:1140 (August 2021).

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

A. Except as provided in Subsection B of this Section, each operator shall report in accordance with §325 the existence of any of the following safety-related conditions involving facilities in service: [49 CFR 191.23(a)]

1. in the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result; [49 CFR 191.23(a)(1)]

2. in the case of a UNGSF, general corrosion that has reduced the wall thickness of any metal component to less than that required for the well's maximum operating pressure, or localized corrosion pitting to a degree where leakage might result; [49 CFR 191.23(a)(2)]

3. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of a UNGSF or LNG facility that contains, controls, or processes gas or LNG; [49 CFR 191.23(a)(3)]

4. any crack or other material defect that impairs the structural integrity or reliability of a UNGSF or an LNG facility that contains, controls, or processes gas or LNG; [49 CFR 191.23(a)(4)]

5. any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, or the serviceability or the structural integrity of a UNGSF; [49 CFR 191.23(a)(5)]

6. any malfunction or operating error that causes the pressure, plus the margin (build-up) allowed for operation of pressure limiting or control devices, to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG; [49 CFR 191.23(a)(6)]

7. a leak in a pipeline, UNGSF, or LNG facility containing or processing gas or LNG that constitutes an emergency; [49 CFR 191.23(a)(7)]

8. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of a LNG storage tank; [49 CFR 191.23(a)(8)]

9. any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline, UNGSF, or an LNG facility that contains or processes gas or LNG. [49 CFR 191.23(a)(9)]

10. for transmission pipelines only, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§1161, 2720.E, and 2939. The reporting requirement of this Paragraph A.10 is not applicable to gathering lines, distribution lines, LNG facilities, or underground natural gas storage facilities (See Paragraph A.6 of this Section); [49 CFR 191.23(a)(10)]

11. any malfunction or operating error that causes the pressure of a UNGSF using a salt cavern for natural gas storage to fall below its minimum allowable operating pressure, as defined by the facility's state or federal operating permit or certificate, whichever pressure is higher; [49 CFR 191.23(a)(11)]

B. A report is not required for any safety-related condition that: [49 CFR 191.23(b)]

1. exists on a master meter system or a customer-owned service line; [49 CFR 191.23(b)(1)]

2. is an incident or results in an incident before the deadline for filing the safety-related condition report; [49 CFR 191.23(b)(2)]

3. exists on a pipeline (other than an UNGSF or an LNG facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or [49 CFR 191.23(b)(3)]

4. is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for: [49 CFR 191.23(b)(4)]

a. conditions under Paragraph A.1 of this Section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and [49 CFR 191.23(b)(4)(i)]

b. any condition under Paragraph A.10 of this Section; [49 CFR 191.23(b)(4)(ii)]

5. exists on an UNGSF, where a well or wellhead is isolated, allowing the reservoir or cavern and all other components of the facility to continue to operate normally and without pressure restriction. [49 CFR 191.23(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).

§325. Filing Safety-Related Condition Reports [49 CFR 191.25]

A. Each report of a safety-related condition under §323.A.1-9 of this Part must be filed (received by the associate administrator/commissioner) in writing within five working days (not including Saturday, Sunday, or federal holidays) after the day a representative of an operator first determines that the condition exists, but not later than 10 working days after the day a representative of an operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in Subsection C of this Section. [49 CFR 192.25(a)]

B. Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in §323.A.10 for a gas transmission pipeline must be filed (received by the associate administrator/commissioner) in writing within five calendar days of the exceedance using the reporting methods and report requirements described in Subsection C of this Section. [49 CFR 191.25(b)]

C. Reports shall be mailed to the Commissioner of Conservation, Office of Conservation, PO Box 94275, Baton Rouge, LA 70804-9275 or may be transmitted by electronic mail to PipelineInspectors@la.gov and concurrently to the Office of Pipeline Safety Administration, U.S. Department of Transportation at Information ResourcesManager@dot.gov or by facsimile at (202) 366-7128. For a report made pursuant to §323.A.1-9, the report must be headed "Safety-Related Condition Report." For a report made pursuant to §323.A.10, the report must be headed "Maximum Allowable Operating Pressure Exceedances." All reports must provide the following information: [49 CFR 191.25(c)]

1. name and principal address of operator; [49 CFR 191.25(c)(1)]

2. date of report; [49 CFR 191.25(c)(2)]

3. name, job title, and business telephone number of person submitting the report; [49 CFR 191.25(c)(3)]

4. name, job title, and business telephone number of person who determined that the condition exists; [49 CFR 191.25(c)(4)]

5. date condition was discovered and date condition was first determined to exist; [49 CFR 191.25(c)(5)]

6. location of condition, with reference to the state (and town, city, or parish) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline; [49 CFR 191.25(c)(6)]

7. description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored; [49 CFR 191.25(c)(7)]

8. the corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action. [49 CFR 191.25(c)(8)]

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 30:1223 (June 2004), amended LR 35:2800 (December 2009), LR 44:1033 (June 2018), LR 46:1576 (November 2020).

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

A. Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:

1. Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595. [49 CFR 191.29(a)(1)]

2. The name of and address for the operator. [49 CFR 191.29(a)(2)]

3. The name and contact information of a pipeline company employee, to be displayed on a public website, who will serve as a contact for questions from the general public about the operator's NPMS data. [49 CFR 191.29(a)(3)]

B. The information required in Subsection A of this Section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595. [49 CFR 191.29(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 44:1033 (June 2018).

Chapter 4. Appendix A [49 CFR Part 191]

§401. Appendix A to Subpart 2—Procedure for Determining Reporting Threshold

A. Procedure for Determining Reporting Threshold

I. Property Damage Threshold Formula

A. Each year after calendar year 2021, the Administrator will publish a notice on PHMSA's website announcing the updates to the property damage threshold criterion that will take effect on July 1 of that year and will remain in effect until the June 30 of the next year. The property damage threshold used in the definition of an Incident at §303 shall be determined in accordance with the following formula:

$$T_r = T_p \times \frac{CPI_r}{CPI_p}$$

Where:

Tr is the revised damage threshold, Tp is the previous damage threshold, CPIr is the average Consumer Price Indices for all Urban Consumers (CPI–U) published by the Bureau of Labor Statistics each month during the most recent complete calendar year, and CPIp is the average CPI–U for the calendar year used to establish the previous property damage criteria.

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 47:1141 (August 2021).

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]

§501. What is the Scope of this Subpart? [49 CFR 192.1]

A. This Subpart prescribes minimum safety requirements for pipeline facilities and the transportation of gas by pipeline within the state of Louisiana, including pipeline facilities and the transportation of gas within the coastal zone limits as defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). [49 CFR 192.1(a)]

B. This regulation does not apply to: [49 CFR 192.1(b)]

1. offshore gathering of gas in state waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream; [49 CFR 192.1(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 [49 CFR 192.1 (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; [49 CFR 192.1 (b)(3)]

4. onshore gathering of gas [49 CFR 192.1(b)(4)]:

a. through a pipeline that operates at less than 0 psig (0 kPa) [49 CFR 192.1(b)(4)(i)];

b. through a pipeline that is not a regulated onshore gathering line (as determined in §508) [49 CFR 192.1(b)(4)(ii)]; and

c. within inlets of the Gulf of Mexico, except for the requirements in §2712; or [CFR 49 192. 1(b)(4)(iii)]

5. any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to [49 CFR 192.1(b)(5)]:

a. fewer than 10 customers, if no portion of the system is located in a public place [49 CFR 192.1(b)(5)(i)]; or

b. a single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place) [49 CFR 192.1(b)(5)(ii)].

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 30:1224 (June 2004), amended LR 33:474 (March 2007), LR 35:2800 (December 2009).

§503. Definitions [49 CFR 192.3]

A. As used in this Part:

Abandoned—permanently removed from service.

Active Corrosion—continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.

Administrator—the administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Alarm—an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

Building—any structure in which gas can accumulate.

Business—a permanent structure occupied for the express usage of wholesale or retail sales, services, the manufacture or storage of products, or a public building.

Business District—an area of two or more businesses within 100 yards (300 feet) of each other and within 100 yards along the linear length of any gas pipeline. The district will extend 100 feet past the defined boundaries of the last business in the district.

Commissioner—the Commissioner of Conservation or any person to whom he has delegated authority in the matter concerned.

Control Room—an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

Controller—a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

Customer Meter—the meter that measures the transfer of gas from an operator to a customer.

Distribution Line—a pipeline other than a gathering or transmission line.

Electrical Survey—a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

Engineering Critical Assessment (ECA)—a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.

Exposed Underwater Pipeline—an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

Gas—natural gas, flammable gas, or gas which is toxic or corrosive.

Gathering Line—a pipeline that transports gas from a current production facility to a transmission line or main.

Gulf of Mexico and *its Inlets*—the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to Navigation—for the purposes of this Part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.

High Pressure Distribution System—a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Line Section—a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

Listed Specification—a specification listed in Section I of Appendix B of this Subpart.

Low-Pressure Distribution System—a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main—a distribution line that serves as a common source of supply for at least one service line.

Master Meter System—a pipeline system for distributing gas within, but not limited to, a definable area such as a mobile home park, housing project, apartment complex or university, where the operator purchases meter gas from an outside source for resale through a gas pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as rents.

Maximum Actual Operating Pressure—the maximum pressure that occurs during normal operations over a period of one year.

Maximum Allowable Operating Pressure (MAOP)—the maximum pressure at which a pipeline or segment of a pipeline may be operated under this Subpart.

Moderate Consequence Area—

a. an onshore area that is within a potential impact circle, as defined in § 3303, containing either:

i. five or more buildings intended for human occupancy; or

ii. 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, as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1 of the 2013 Edition (see: https:// www.fhwa.dot.gov/planning/processes /statewide/related/highway_functional_classifications/fcauab .pdf), and that does not meet the definition of high consequence area, as defined in §3303;

b. the length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either five or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either five or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with four or more lanes.

Municipality—a city, parish, or any other political subdivision of Louisiana.

Natural Gas Distribution System—a company, municipality, or political subdivision that purchases or receives natural gas, and through its own intrastate pipeline system, distributes natural gas to end users in Louisiana such as residential, commercial, industrial, and wholesale customers, and shall include master meter systems.

Non Rural Area—

a. an area within the limits of any incorporated city, town, or village;

b. any designated residential or commercial area such as a subdivision, business or shopping center, or community development;

c. any Class 3 or 4 location as defined in §503; or

d. any other area so designated by the commissioner.

Offshore—beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

Operator—a person who engages in the transportation of gas.

Outer Continental Shelf—all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Person—any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

Petroleum Gas—propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1,434 kPa) gage at 100°F (38°C).

Pipe—any pipe or tubing used in the transportation of gas, including pipe-type holders.

Pipeline—all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies.

Pipeline Environment—includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

Pipeline Facility—new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

Production Facility—piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation or treating of hydrocarbons, or associated storage or measurement. (To be a production facility under this definition, piping or equipment must be used in the process of extracting hydrocarbons from the ground and preparing it for transportation by pipeline.)

Public Building—a structure which members of the public may congregate such as schools, hospitals, nursing homes, churches, civic centers, post offices, and federal, state and local government buildings.

School System—a pipeline system for distributing natural gas to a public or private pre-kindergarten, kindergarten, elementary, secondary, or high school. Upon request for a revision of service by the school, or by the school system of which the school is a component, the local distribution company providing natural gas service to the school shall, within a reasonable period of time and upon mutual agreement, install a meter at the building wall of each building of the school that utilizes natural gas. The gas piping from the outlet of the meter to the inside of the building shall be installed above ground, and shall be maintained by the school in accordance with the requirements of the Office of the State Fire Marshal. The outside piping that is upstream of the meter to the outlet of the meter shall be owned and maintained by the local distribution company in accordance with minimum pipeline safety regulations. The pipeline system of a school that does not request a revision of service described by this Paragraph shall be deemed a special class system, and subject to the requirements of such system.

Service Line—a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Service Regulator—the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

SMYS—specified minimum yield strength is:

a. for steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

b. for steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §907.B.

Special Class System—a pipeline system for distributing gas to a federal, state, or local government facility or a private facility performing a government function, where the operator receives or purchases gas from an outside source and distributes the gas through a pipeline system to more than one outlet (building) beyond the meter or regulator, which ultimate outlet may, but need not be, individually metered or charged a fee for the gas. Any exemption from pipeline safety regulation granted to master meter systems will apply to special class systems.

State—each of the several states, the District of Columbia, and the Commonwealth of Puerto Rico.

Supervisory Control and Data Acquisition (SCADA) System—a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

Transmission Line—a pipeline, other than a gathering line, that:

a. transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;

b. operates at a hoop stress of 20 percent or more of SMYS; or

c. transports gas within a storage field.

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

Transportation of Gas—the gathering, transmission, or distribution of gas by pipeline, or the storage of gas, in or affecting intrastate, interstate or foreign commerce.

Underground Natural Gas Storage Facility—means a facility that stores natural gas in an underground facility incident to natural gas transportation, including:

a. a depleted hydrocarbon reservoir;

b. an aquifer reservoir; or

c. a solution-mined salt cavern reservoir, including associated material and equipment used for injection, withdrawal, monitoring, or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment.

Underground Natural Gas Storage Facility (UNGSF)—a gas pipeline facility that stores natural gas underground incidental to the transportation of natural gas, including:

a. a depleted hydrocarbon reservoir;

b. an aquifer reservoir; or

c. a solution-mined salt cavern

d. In addition to the reservoir or cavern, a UNGSF includes injection, withdrawal, monitoring, and observation wells; wellbores and downhole components; wellheads and associated wellhead piping; wing-valve assemblies that isolate the wellhead from connected piping beyond the wing-valve assemblies; and any other equipment, facility, right-of-way, or building used in the underground storage of natural gas.

Weak Link—a device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed.

Welder—a person who performs manual or semi-automatic welding.

Welding Operator—a person who operates machine or automatic welding equipment.

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).

§505. Class Locations [49 CFR 192.5]

A. This Section classifies pipeline locations for purposes of this Part. The following criteria apply to classifications under this Section. [49 CFR 192.5(a)]

1. A class location unit is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. [49 CFR 192.5(a)(1)]

2. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy. [49 CFR 192.5(a)(2)]

B. Except as provided in Subsection C of this Section, pipeline locations are classified as follows: [49 CFR 192.5(b)]

1. a Class 1 location is: [49 CFR 192.5(b)(1)]

a. an offshore area; or [49 CFR 192.5(b)(1)(i)]

b. any class location unit that has 10 or fewer buildings intended for human occupancy; [49 CFR 192.5(b)(1)(ii)]

2. a Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy; [49 CFR 192.5(b)(2)]

3. a Class 3 location is: [49 CFR 192.5(b)(3)]

a. any class location unit that has 46 or more buildings intended for human occupancy; or [49 CFR 192.5(b)(3)(i)]

b. an area where the pipeline lies within 100 yards (91 meters) of either a building or 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 five days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive); [49 CFR 192.5(b)(3)(ii)]

4. a Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent. [49 CFR 192.5(b)(4)]

C. The length of Class locations 2, 3, and 4 may be adjusted as follows. [49 CFR 192.5(c)]

1. A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground. [49 CFR 192.5(c)(1)]

2. When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster. [49 CFR 192.5(c)(2)]

D. An operator must have records that document the current class location of each gas transmission pipeline segment and that demonstrate how the operator determined each current class location in accordance with this Section. [49 CFR 192.5(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 20:443 (April 1994), LR 24:1307 (July 1998), LR 27:1537 (September 2001), LR 30:1226 (June 2004), LR 46:1578 (November 2020).

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

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

1. Availability of standards incorporated by reference. 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, email fedreg.legal@ nara.gov or go to www.archives.gov/federal-register/cfr/ibr-locations.html.

c. Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

2. Reserved.

Source and Name of Referenced Material	Approved for Title 43 Reference
B. American Petroleum Institute (API), 200 Massachusetts Ave N.W., Suite 1100, Washington, D.C. 20001, and phone: 202-682-8000, Web site: *https://www.api.org/*.	
1. API Recommended Practice 5L1, “Recommended Practice for Railroad Transportation of Line Pipe,” 7th edition, September 2009, (API RP 5L1).	§715.A
2. API Recommended Practice 5LT, “Recommended Practice for Truck Transportation of Line Pipe,” First edition, March 2012, (API RP 5LT).	§715.C
3. API Recommended Practice 5LW, “Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels,” 3rd edition, September 2009, (API RP 5LW).	§715.B
4. API Recommended Practice 80, “Guidelines for the Definition of Onshore Gas Gathering Lines,” 1st edition, April 2000, (API RP 80).	§508.A

Source and Name of Referenced Material	Approved for Title 43 Reference
5. API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," 1st edition, December 2003, (API RP 1162).	§§2716.A; 2716.B; 2716.C
6. API Recommended Practice 1165, "Recommended Practice for Pipeline SCADA Displays," First edition, January 2007, (API RP 1165).	§2731. C
7. API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013, (API Spec 5L).	§§705.E ; 912.A-E; 913; Item I of 5103
8. ANSI/API Specification 6D, "Specification for Pipeline Valves,"23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata2 (/November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011) Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D).	§1105.A
9. 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),	§§1305.A; 1307.A; 1309.C; 1321.C; Item II, 5103.
10. API Recommended Practice 1170, "Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage," First edition, July 2015 (API RP 1170).	§512
12. API STANDARD 1163, "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018, (API STD 1163).	§2145
C. ASME International (ASME), Three Park Avenue, New York, NY 10016, 800-843-2763 (U.S./Canada), http://www.asme.org/.	
1. ASME/ANSI B16.1-2005, "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)," August 31, 2006, (ASME/ANSI B16.1).	§1107.C
2. ASME/ANSI B16.5 - 2003, "Pipe Flanges and Flanged Fittings," October 2004, (ASME/ANSI B16.5).	§§ 1107.A; 1509; 2707
3. ASME B16.40-2008, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems," March 18, 2008, approved by ANSI, (ASME B16.40- 2008).	§5103, Item 1
4. ASME/ANSI B31G - 1991 (Reaffirmed 2004), "Manual for Determining the Remaining Strength of Corroded Pipelines," 2004, (ASME/ ANSI B31G). , IBR approved for §§ 2137.C, 2732.A, 2912.B, and 3333.A.	§§ 2137.C; 2732.A; 2912; 3333
5. ASME/ANSI B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines," 2004, (ASME/ANSI B31.8S-2004).	§§ 3303; 3307.A; 3307.B; 3311.A; 3311.A.9; 3311.A.11; 3311.A.12; 3311.A.13; 3313.A; 3313.B; 3313.C; 3317.A; 3317.B; 3317.C; 3317.D; 3317.E; 3321.A; 3323.B; 3325.B; 3327.B; 3327.C; 3329.B; 3333.C; 3335.A; 3335.B; 3337.C; 3339.A; 3345.A
6. ASME Boiler & Pressure Vessel Code, Section I, "Rules for Construction of Power Boilers 2007," 2007 edition, July 1, 2007, (ASME BPVC, Section I).	§ 1113.A
7. ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1).	§§ 1113.A; 1113.B; 1113.D; 1125.B.3

Source and Name of Referenced Material	Approved for Title 43 Reference
8. ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 "Alternate Rules, Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2).	§§1113.B; 1125.B.3
9. 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.	§§1307.A; 1307.A; 5103 Item II
D. American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800-222-2768, website: https://www.asnt.org/.	
1. ANSI/ASNT ILI - PQ - 2005(2010), "In-line Inspection Personnel Qualification and Certification," Reapproved October 11, 2010, (ANSI/ ASNT ILI - PQ)	§§913; 5103 Item I
2. [Reserved]	
E. ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832-9585, Web site: http://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)	§§913; 5103 Item I
2. ASTM A106/A106M-10, "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service," approved October 1, 2010, (ASTM A106/A106M)	§§913; 5103 Item I
3. ASTM A333/A333M-11, "Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service," approved April 1, 2011, (ASTM A333/A333M)	§§913; 5103 Item I
4. ASTM A372/A372M-10, "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels," approved October 1, 2010, (ASTM A372/A372M)	§1137.B
5. 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)	§§ 913; 5103 Item I
6. ASTM A578/A578M-96 (reapproved 2001), "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications," (ASTM A578/A578M)	§ 912.C
7. ASTM A671/A671M-10, "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures," approved April 1, 2010, (ASTM A671/A671M)	§§913; 5103 Item I
8. ASTM A672/A672M-09, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures," approved October 1, 2009, (ASTM A672/672M)	§§ 913; 5103 Item I
9. 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/A691M)	§§ 913; 5103 Item I
10. ASTM D638-03, "Standard Test Method for Tensile Properties of Plastics," 2003, (ASTM D638)	§§1513.A; 1513.B
11. (ASTM D2513-12ae1). ASTM D2513-18a, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings," approved August 1, 2018, (ASTM D2513),	§5103, Item 1
12. ASTM D2517-00, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings," (ASTM D 2517).	§§ 1151.A; 1511.D; 1513.A; 5103 Item I

Source and Name of Referenced Material	Approved for Title 43 Reference
13. ASTM D2564-12, "Standard Specification for Solvent Cements for Poly (Vinyl Chloride) (PVC) Plastic Piping Systems," Aug. 1, 2012, (ASTM D2564-12).	§1511.B.2
14. ASTM F1055-98 (Reapproved 2006), "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing," March 1, 2006, (ASTM F1055-98 (2006)).	§§1513.A; 5103 Item I
15. ASTM F1924-12, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1924-12).	§5103 Item I
16. ASTM F1948-12, "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing," April 1, 2012, (ASTM F1948-12).	§5103 Item I
17. ASTM F1973-13, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems," May 1, 2013, (ASTM F1973-13)	§§1164.B; 5103 Item I
18. ASTM F2145-13, "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing," May 1, 2013, (ASTM F2145-13)	§5103 Item I
19. ASTM F 2600-09, "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing," April 1, 2009, (ASTM F 2600-09)	§5103 Item I
20. ASTM F2620-19, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings," approved February 1, 2019, (ASTM F2620)	§§1511.C; 1515.B.2.a
21. ASTM F2767-12, "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution," Oct. 15, 2012, (ASTM F2767-12)	§5103 Item I
22. ASTM F2785-12, "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings," Aug. 1, 2012, (ASTM F2785-12)	§ 5103 Item I
23. ASTM F2817-10, "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair," Feb. 1, 2010, (ASTM F2817-10)	§ 5103 Item I
24. ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings," Nov. 27, 2012, (ASTM F2945-12a)	§ 5103 Item I
F. Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI)), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: www.gastechnology.org.	
1. GRI 02/0057 (2002) "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology"	§ 3327.C
2. [Reserved]	
G. 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-44-2010, Standard Practice, "Steel Pipeline Flanges," 2010 edition, (including Errata (May 20, 2011)), (MSS SP-44).	§ 1107.A
2. [Reserved]	
H. NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084: phone: 281-228-6223 or 800-797-6223, Web site: http://www.nace.org/Publications/.	
1. ANSI/NACE SP0502-2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," revised June 24, 2010, (NACE SP0502).	§§ 3323.B; 3325.B; 3331.D; 3335.B; 3339.A

Source and Name of Referenced Material	Approved for Title 43 Reference
2. NACE Standard Practice 0102 - 2010, "In-Line Inspection of Pipelines," Revised 2010 - 03 - 13, (NACE SP0102).	§§ 1110.A; 2145
I. National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984-7275, Web site: http://www.nfpa.org/.	
1. NFPA-30 (2012), "Flammable and Combustible Liquids Code," 2012 edition, June 20, 2011, including Errata 30-12-1 (September 27, 2011) and Errata 30-12-2 (November 14, 2011), (NFPA-30).	§2935.B
2. NFPA-58 (2004), "Liquefied Petroleum Gas Code (LP-Gas Code)," (NFPA-58).	§§ 511.A; 511.B; 511.C
3. NFPA-59 (2004), "Utility LP-Gas Plant Code," (NFPA-59).	§§ 511.A; 511.B; 511.C
4. NFPA-70 (2011), "National Electrical Code," 2011 edition, issued August 5, 2010, (NFPA-70).	§§ 1123.E; 1149.C
J. Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713-630-0505, toll free: 866-866-6766, Web site: http://www.ttoolboxes.com/. (Contract number PR-3-805.)	
1. AGA, Pipeline Research Committee Project, PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR-3-805 (R-STRENG)).	§§ 2732.A; 2912.B; 3333.A; 3333.D
2. [Reserved]	
K. Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825 Irving TX 75062, phone: 469-499-1044, http://www.plasticpipe.org/.	
1. PPI TR-3/2012, HDB/HDS/PDB/SDB/MRS/CRS, Policies, "Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe," updated November 2012, (PPI TR-3/2012)	§ 921
2. PPI TR-4, HDB/HDS/SDB/MRS, Listed Materials, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Rating For Thermoplastic Piping Materials or Pipe," updated March, 2011, (PPI TR-4/2012)	§ 921

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

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

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

A. An operator must use API RP 80 (incorporated by reference, see §507), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under Subsection B of this Section [49 CFR 192.8(a)].

1. The beginning of gathering, under Section 2.2(a)(1) of API RP 80, may not extend beyond the furthermost downstream point in a production operation as defined in Section 2.3 of API RP 80. This furthermost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of "production and preparation for transportation or delivery of hydrocarbon gas" within the meaning of "production operation" [49 CFR 192.8(a)(1)].

2. The endpoint of gathering, under Section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant [49 CFR 192.8(a)(2)].

3. If the endpoint of gathering, under Section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the administrator/commissioner finds a longer separation distance is justified in a particular case (see 49 CFR §190.9) [49 CFR 192.8(a)(3)].

4. The endpoint of gathering, under Section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline [49 CFR 192.8(a)(4)].

B. For purposes of §509, "regulated onshore gathering line" means [49 CFR 192.8(b)]:

1. each 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)]; and

2. as applicable, additional lengths of line described in the fourth column to provide a safety buffer [49 CFR 192.8(b)(2)].

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.
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.

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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. Requirements. An operator of a gathering line must follow the safety requirements of this Part as prescribed by this Section [49 CFR 192.9(a)].

B. Offshore Lines. An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§1110, 1515.E, 2145, 2306, 2707, 2719.E, 2724, 2910, 2912, and Chapter 33 of this Subpart. [49 CFR 192.9(b)].

C. Type A Lines. An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§1110, 1515.E, 2145, 2306, 2707, 2719.E, 2724, 2910 2912, and in Chapter 33 of this Subpart. However, operators of Type A regulated onshore gathering lines in a Class 2 location may demonstrate compliance with Chapter 31 by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks. [49 CFR 192.9(c)].

D. Type B Lines. An operator of a Type B regulated onshore gathering line must comply with the following requirements [49 CFR 192.9(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, 1165, 1307.C, 1515.E, and 2305; [49 CFR 192.9(d)(1)];

2. if the pipeline is metallic, control corrosion according to requirements of Chapter 21 of this Part applicable to transmission lines except the requirements in §2145; [49 CFR 192.9(d)(2)];

3. if the pipeline contains plastic pipe or components, the operator must comply with all applicable requirements of this part for plastic pipe components; [49 CFR 192.9(d)(3)];

4. carry out a damage prevention program under §2714; [49 CFR 192.9(d)(4)];

5. establish a public education program under §2716; [49 CFR 192.9(d)(5)];

6. establish the MAOP of the line under §2719.A,B and C. [49 CFR 192.9(d)(6)];

7. install and maintain line markers according to the requirements for transmission lines in §2907; and [49 CFR 192.9(d)(7)];

8. 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). [49 CFR 192.9(d)(8)]

E. 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 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)].

2. 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)].

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)].

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).

§510. Outer Continental Shelf Pipelines [49 CFR 192.10]

A. Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Outer Continental Shelf Lands Act 43 U.S.C. 1331) must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic located near the transfer point. If a transfer point is located subsea, then the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to PHMSA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the regional director and the MMS regional supervisor will make a joint determination of the transfer point [49 CFR 192.10].

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 27:1537 (September 2001), amended LR 30:1227 (June 2004), LR 33:477 (March 2007).

§511. Petroleum Gas Systems [49 CFR 192.11]

A. Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this Subpart and NFPA 58 and NFPA 59 (incorporated by reference, see §507). [49 CFR 192.11(a)]

B. Each pipeline system subject to this Subpart that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this Subpart and of NFPA 58 and 59 (incorporated by reference, see §507). [49 CFR 192.11(b)]

C. In the event of a conflict between this Subpart and NFPA 58 and 59, NFPA 58 and NFPA 59 prevail. [49 CFR 192.11(c)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 9:220 (April 1983), amended LR 10:511 (July 1984), LR 20:443 (April 1994), LR 24:1307 (July 1998), LR 30:1227 (June 2004), LR 44:1035 (June 2018).

§512. Underground Natural Gas Storage Facilities [49 CFR 192.12]

A. Underground natural gas storage facilities (UNGSFs), as defined in §503, are not subject to any requirements of this Part aside from this Section.

1. Salt Cavern UNGSFs [49 CFR 192.12(a)]

a. Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed after March 13, 2020, must meet all the provisions of API RP

1170 (incorporated by reference, see §507), the provisions of section 8 of API RP 1171 (incorporated by reference, see §507) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and Paragraphs A.3 and A.4 of this Section prior to commencing operations. [49 CFR 192.12(a)(1)]

b. Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed between July 18, 2017, and March 13, 2020, must meet all the provisions of API RP 1170 (incorporated by reference, see §507) and Paragraph A.3 of this Section prior to commencing operations, and must meet all the provisions of section 8 of API RP 1171 (incorporated by reference, see §507) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and Paragraph A.4 of this Section, by March 13, 2021. [49 CFR 192.12(a)(2)]

c. Each UNGSF that uses a solution-mined salt cavern for natural gas storage and was constructed on or before July 18, 2017, must meet the provisions of API RP 1170 (incorporated by reference, see §507), sections 9, 10, and 11, and Paragraph A.3 of this Section, by January 18, 2018, and must meet all provisions of section 8 of API RP 1171 (incorporated by reference, see §507) that are applicable to the physical characteristics and operations of a solution-mined salt cavern UNGSF, and Paragraph A.4 of this Section, by March 13, 2021. [49 CFR 192.12(a)(3)]

2. Depleted Hydrocarbon and Aquifer Reservoir UNGSFs [49 CFR 192.12(b)]

a. Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was constructed after July 18, 2017, must meet all provisions of API RP 1171 (incorporated by reference, see §507), and Paragraphs A.3 and A.4 of this Section, prior to commencing operations. [49 CFR 192.12(b)(1)]

b. Each UNGSF that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage and was constructed on or before July 18, 2017, must meet the provisions of API RP 1171 (incorporated by reference, see §507), sections 8, 9, 10, and 11, and Paragraph A.3 of this Section, by January 18, 2018, and must meet all provisions of Paragraph A.4 of this Section by March 13, 2021. [49 CFR 192.12(b)(2)]

3. Procedural Manuals. Each operator of a UNGSF must prepare and follow for each facility one or more manuals of written procedures for conducting operations, maintenance, and emergency preparedness and response activities under Paragraphs A.1 and A.2 of this Section. Each operator must keep records necessary to administer such procedures and review and update these manuals at intervals not exceeding 15 months, but at least once each calendar year. Each operator must keep the appropriate parts of these manuals accessible at locations where UNGSF work is being performed. Each operator must have written procedures in place before commencing operations or beginning an activity not yet implemented. [49 CFR 192.12(c)]

4. Integrity Management Program [49 CFR 192.12(d)]

a. Integrity Management Program Elements. The integrity management program for each UNGSF under this Paragraph A.4 must consist, at a minimum, of a framework developed under API RP 1171 (incorporated by reference, see §507), section 8 ("Risk Management for Gas Storage Operations"), and that also describes how relevant decisions will be made and by whom. An operator must make continual improvements to the program and its execution. The integrity management program must include the following elements: [49 CFR 192.12(d)(1)]

i. a plan for developing and implementing each program element to meet the requirements of this Section; [49 CFR 192.12(d)(1)(i)]

ii. an outline of the procedures to be developed; [49 CFR 192.12(d)(1)(ii)]

iii. the roles and responsibilities of UNGSF staff assigned to develop and implement the procedures required by this Paragraph A.4; [49 CFR 192.12(d)(1)(iii)]

iv. a plan for how staff will be trained in awareness and application of the procedures required by this Paragraph A.4; [49 CFR 192.12(d)(1)(iv)]

v. timelines for implementing each program element, including the risk analysis and baseline risk assessments; and [49 CFR 192.12(d)(1)(v)]

vi. a plan for how to incorporate information gained from experience into the integrity management program on a continuous basis. [49 CFR 192.12(d)(1)(vi)]

b. Integrity Management Baseline Risk-Assessment Intervals. No later than March 13, 2024, each UNGSF operator must complete the baseline risk assessments of all reservoirs and caverns, and at least 40 percent of the baseline risk assessments for each of its UNGSF wells (including wellhead assemblies), beginning with the highest-risk wells, as identified by the risk analysis process. No later than March 13, 2027, an operator must complete baseline risk assessments on all its wells (including wellhead assemblies). Operators may use prior risk assessments for a well as a baseline (or part of the baseline) risk assessment in implementing its initial integrity management program, so long as the prior assessments meet the requirements of API RP 1171 (incorporated by reference, see §507), section 8, and continue to be relevant and valid for the current operating and environmental conditions. When evaluating prior risk-assessment results, operators must account for the growth and effects of indicated defects since the time the assessment was performed.49 CFR 192.12(d)(2)]

c. Integrity Management Re-Assessment Intervals. The operator must determine the appropriate interval for risk assessments under API RP 1171 (incorporated by reference, see §507), subsection 8.7.1, and this Paragraph A.4 for each reservoir, cavern, and well, using the results from earlier assessments and updated risk analyses. The re-assessment interval for each reservoir, cavern, and well must not exceed seven years from the date of the baseline assessment for each reservoir, cavern, and well.49 CFR 192.12(d)(3)]

d. Integrity Management Procedures and Recordkeeping. Each UNGSF operator must establish and follow written procedures to carry out its integrity management program under API RP 1171 (incorporated by reference, see §507), section 8 ("Risk Management for Gas Storage Operations"), and this Paragraph A.4. The operator must also maintain, for the useful life of the UNGSF, records that demonstrate compliance with the requirements of this Paragraph A.4. This includes records developed and used in support of any identification, calculation, amendment, modification, justification, deviation, and determination made, and any action taken to implement and evaluate any integrity management program element.49 CFR 192.12(d)(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 45:69 (January 2019), amended LR 46:1580 (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 that is readied for service after the date in the second column, unless [49 CFR 192.13(a)]:

1. the pipeline has been designed, installed, constructed; initially inspected, and initially tested in accordance with this Subpart; or [49 CFR 192.13(a)(1)]

2. the pipeline qualifies for use under this Subpart according to the requirements in §514 [49 CFR 192.13(a)(2)].

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
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 CFR 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
All other pipelines.	November 12, 1970

C. Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this Part. [49 CFR 192.13(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).

§514. Conversion to Service Subject to this Part [49 CFR 192.14]

A. A steel pipeline previously used in service not subject to Part XIII qualifies for use under this Part if the operator prepares and follows a written procedure to carry out the following requirements. [49 CFR 192.14(a)]

1. The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation. [49 CFR 192.14(a)(1)]

2. The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline. [49 CFR 192.14(a)(2)]

3. All known unsafe defects and conditions must be corrected in accordance with this Part. [49 CFR 192.14(a)(3)]

4. The pipeline must be tested in accordance with Chapter 23 of this Subpart to substantiate the maximum allowable operating pressure permitted by Chapter 27 of this Subpart. [49 CFR 192.14(a)(4)]

B. Each operator must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of Subsection A of this Section. [49 CFR 192.14(b)]

C. An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by §322 of this Chapter. [49 CFR 192.14(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 10:512 (July 1984), LR 30:1227 (June 2004), LR 44:1035 (June 2018).

§515. Rules of Regulatory Construction [49 CFR 192.15]

A. As used in this regulation: [49 CFR 192.15(a)]

Includes—including but not limited to.

May—"is permitted to" or "is authorized to;"

May not—"is not permitted to" or "is not authorized to."

Shall—used in the mandatory and imperative sense.

B. In Part XIII: [49 CFR 192.15(b)]

1. words importing the singular include the plural; [49 CFR 192.15(b)(1)]

2. words importing the plural include the singular; and [49 CFR 192.15(b)(2)]

3. words importing the masculine gender include the feminine. [49 CFR 192.15(b)(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 30:1227 (June 2004), LR 33:478 (March 2007).

§516. Customer Notification [49 CFR 192.16]

A. This Section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this Section, customer's buried piping does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, maintain means monitor for corrosion according to §2117 if the customer's buried piping is metallic, survey for leaks according to §2923, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition. [49 CFR 192.16(a)]

B. Each operator shall notify each customer once in writing of the following information. [49 CFR 192.16(b)]

1. The operator does not maintain the customer's buried piping. [49 CFR 192.16(b)(1)]

2. If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage. [49 CFR 192.16(b)(2)]

3. Buried gas piping should be: [49 CFR 192.16(b)(3)]

a. periodically inspected for leaks; [49 CFR 192.16(b)(3)(i)]

b. periodically inspected for corrosion if the piping is metallic; and [49 CFR 192.16(b)(3)(ii)]

c. repaired if any unsafe condition is discovered. [49 CFR 192.16(b)(3)(iii)]

4. When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand. [49 CFR 192.16(b)(4)]

5. The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping. [49 CFR 192.16(b)(5)]

C. Each operator shall notify each customer not later than August 14, 1996 or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by customers. [49 CFR 192.16(c)]

D. Each operator must make the following records available for inspection by the administrator or a state agency participating under 49 U.S.C. 60105 or 60106: [49 CFR 192.16(d)]

1. a copy of the notice currently in use; and [49 CFR 192.16(d)(1)

2. evidence that notices have been sent to customers within the previous three years. [49 CFR 192.16(d)(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 24:1307 (July 1998), amended LR 27:1537 (September 2001), LR 30:1228 (June 2004).

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

A. An operator must provide any notification required by this Section by: [49 CFR 192.18(a)]

1. sending the notification by electronic mail to InformationResourcesManager@dot.gov; or [49 CFR 192.18(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 192.18(a)(2)]

B. For intrastate facilities subject to the jurisdiction of the Office of Conservation, a copy must also be submitted to Office of Conservation, P.O. Box 94275, Baton Rouge, LA 70804-9275 or by electronic mail to PipelineInspectors@la.gov. [49 CFR 192.18(b)]

C. Unless otherwise specified, if the notification is made pursuant to §2305.B, §2707E.4, §2707.E.5, §2724.C.2.c, §2724.C.6, §2732.B.3, §2910.C.7, §2912.D.3.d, §2912.E.2.i.e, §3321.A.7, 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. [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 7. Materials [49 CFR Part 192 Subpart B]

§701. Scope [49 CFR 192.51]

A. This Chapter prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines. [49 CFR 192.51]

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 10:512 (July 1984), LR 30:1228 (June 2004).

§703. General [49 CFR 192.53]

A. Materials for pipe and components must be: [49 CFR 192.53]

1. able to maintain the structural integrity of the pipeline under temperature and other environment conditions that may be anticipated; [49 CFR 192.53(a)]

2. chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and [49 CFR 192.53(b)]

3. qualified in accordance with the applicable requirements of this Chapter. [49 CFR 192.53(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 10:512 (July 1984), LR 30:1228 (June 2004).

§705. Steel Pipe [49 CFR 192.55]

A. New steel pipe is qualified for use under this Subpart if: [49 CFR 192.55(a)]

1. it was manufactured in accordance with a listed specification; [49 CFR 192.55(a)(1)]

2. it meets the requirements of: [49 CFR 192.55(a)(2)]

a. Section II of §5103, Appendix B to this Subpart; or [49 CFR 192.55(a)(2)(i)]

b. if it was manufactured before November 12, 1970, either Section II or III of §5103, Appendix B to this Subpart; or [49 CFR 192.55(a)(2)(ii)]

3. it is used in accordance with Subsection C or D of this Section. [49 CFR 192.55(a)(3)]

B. Used steel pipe is qualified for use under this Subpart if: [49 CFR 192.55(b)]

1. it was manufactured in accordance with a listed specification and it meets the requirements of Paragraph II-C of §5103, Appendix B to this Subpart; [49 CFR 192.55(b)(1)]

2. it meets the requirements of: [49 CFR 192.55(b)(2)]

a. Section II of §5103, Appendix B to this Subpart; or [49 CFR 192.55(b)(2)(i)]

b. if it was manufactured before November 12, 1970, either Section II or III of §5103, Appendix B to this Subpart; [49 CFR 192.55(b)(2)(ii)]

3. it has been used in an existing line of the same or higher pressure and meets the requirements of Paragraph II-C of §5103, Appendix B to this Subpart; or [49 CFR 192.55(b)(3)]

4. it is used in accordance with Subsection C of this Section. [49 CFR 192.55(b)(4)]

C. New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 psi (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in Paragraph II-B of §5103, Appendix B to this Subpart. [49 CFR 192.55(c)]

D. Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline. [49 CFR 192.55(d)]

E. New steel pipe that has been cold expanded must comply with the mandatory provisions of API Spec 5L. [49 CFR 192.55(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 9:220 (April 1983), amended LR 10:512 (July 1984), LR 27:1537 (September 2001), LR 30:1228 (June 2004), LR 44:1035 (June 2018).

§709. Plastic Pipe [49 CFR 192.59]

A. New plastic pipe is qualified for use under this Subpart if: [49 CFR 192.59(a)]

1. it is manufactured in accordance with a listed specification; [49 CFR 192.59(a)(1)]

2. it is resistant to chemicals with which contact may be anticipated; and [49 CFR 192.59(a)(2)]

3. it is free of visible defects. [49 CFR 192.59(a)(3)]

B. Used plastic pipe is qualified for use under this Subpart if: [49 CFR 192.59(b)]

1. it was manufactured in accordance with a listed specification; [49 CFR 192.59(b)(1)]

2. it is resistant to chemicals with which contact may be anticipated; [49 CFR 192.59(b)(2)]

3. it has been used only in natural gas service; [49 CFR 192.59(b)(3)]

4. its dimensions are still within the tolerances of the specification to which it was manufactured; and [49 CFR 192.59(b)(4)]

5. it is free of visible defects. [49 CFR 192.59(b)(5)]

C. For the purpose of Paragraphs A.1 and B.1 of this Section, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it: [49 CFR 192.59(c)]

1. meets the strength and design criteria required of pipe included in that listed specification; and [49 CFR 192.59(c)(1)]

2. is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification. [49 CFR 192.59(c)(2)]

D. Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this part. [49 CFR 192.59(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 9:221 (April 1983), amended LR 10:512 (July 1984), LR 30:1229 (June 2004), LR 44:1035 (June 2018), LR 46:1581 (November 2020).

§713. Marking of Materials [49 CFR 192.63]

A. Except as provided in Subsection D and E of this Section each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured. [49 CFR 192.63(a)]

1. as prescribed in the specification or standard to which it was manufactured, except that thermoplastic pipe and fittings made of plastic materials other than polyethylene must be marked in accordance with ASTM D 2513-87 (incorporated by reference, see §507); [49 CFR 192.63(a)(1)

2. to indicate size, material, manufacturer, pressure rating, and temperature rating, and as appropriate, type, grade, and model. [49 CFR 192.63(a)(2)]

B. Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped. [49 CFR 192.63(b)]

C. If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations. [49 CFR 192.63(c)]

D. Subsection A of this Section does not apply to items manufactured before November 12, 1970 that meet all of the following. [49 CFR 192.63(d)]

1. The item is identifiable as to type, manufacturer, and model. [49 CFR 192.63(d)(1)]

2. Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available. [49 CFR 192.63(d)(2)]

E. All plastic pipe and components must also meet the following requirements. [49 CFR 192.63(e)]

1. All markings on plastic pipe prescribed in the listed specification and the requirements of Paragraph E.2 of this Section must be repeated at intervals not exceeding two feet. [49 CFR 192.63(e)(1)]

2. Plastic pipe and components manufactured after December 31, 2019 must be marked in accordance with the listed specification. [49 CFR 192.63(e)(2)]

3. All physical markings on plastic pipelines prescribed in the listed specification and Paragraph E.2 of this Section must be legible until the time of installation. [49 CFR 192.63(e)(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 9:221 (April 1983), amended LR 10:512 (July 1984), LR 18:854 (August 1992), LR 20:443 (April 1994), LR 24:1308 (July 1998), LR 30:1229 (June 2004), LR 38:114 (January 2012), LR 44:1036 (June 2018), LR 46:1581 (November 2020).

§715. Transportation of Pipe [49 CFR 192.65]

A. Railroad. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, see §507) [49 CFR 192.65(a)]

B. Ship or Barge. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, see §507). [49 CFR 192.65(b)]

C. Truck. In a pipeline to be operated at a hoop stress of 20 percent or more SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, see §507). [49 CFR 192.7].

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 9:221 (April 1983), amended LR 10:513 (July 1984), LR 20:444 (April 1994), LR 30:1229 (June 2004), LR 38:114 (January 2012), LR 44:1036 (June 2018).

§717. Records: Material Properties [49 CFR 192.67]

A. For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§703 and 705. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed. [49 CFR 192.67(a)]

B. For steel transmission pipelines installed on or before July 1, 2020, if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§703 and 705, operators must retain such records for the life of the pipeline. [49 CFR 192.67(b)]

C. For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §2724 according to the terms of that Section. [49 CFR 192.67(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 46:1582 (November 2020).

§719. Storage and Handling of Plastic Pipe and Associated Components [49 CFR 192.69]

A. Each operator must have and follow written procedures for the storage and handling of plastic pipe and associated components that meet the applicable listed specifications. [49 CFR 192.69(a)]

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 46:01582 (November 2020).

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

§901. Scope [49 CFR 192.101]

A. This Chapter prescribes the minimum requirements for the design of pipe. [49 CFR 192.101]

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 9:221 (April 1983), amended LR 10:513 (July 1984), LR 30:1229 (June 2004).

§903. General [49 CFR 192.103]

A. Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation. [49 CFR 192.103]

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 9:221 (April 1983), amended LR 10:513 (July 1984), LR 30:1230 (June 2004).

§905. Design Formula for Steel Pipe [49 CFR 192.105]

A. The design pressure for steel pipe is determined in accordance with the following formula. [49 CFR 192.105(a)]

$$P = (2St/D) x F x E x T$$

P = Design pressure in pounds per square inch (kPa) gauge
S = Yield strength in pounds per square inch (kPa) determined in accordance with §907
D = Nominal outside diameter of the pipe in inches (millimeters)
t = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with §909. Additional wall thickness required for concurrent external loads in accordance with §903 may not be included in computing design pressure.
F = Design factor determined in accordance with §911
E = Longitudinal joint factor determined in accordance with §913
T = Temperature derating factor determined in accordance with §915

B. If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under Subsection A of this Section if the temperature of the pipe exceeds 900°F (482°C) at any time or is held above 600°F (316°C) for more than one hour. [49 CFR 192.105(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 9:221 (April 1983), amended LR 10:513 (July 1984), LR 24:1308 (July 1998), LR 27:1537 (September 2001), LR 30:1230 (June 2004).

§907. Yield Strength (S) for Steel Pipe [49 CFR 192.107]

A. For pipe that is manufactured in accordance with a specification listed in Section I of §5103, Appendix B to this Subpart, the yield strength to be used in the design formula in §905 is the SMYS stated in the listed specification, if that value is known. [49 CFR 192.107(a)]

B. For pipe that is manufactured in accordance with a specification not listed in Section I of §5103, Appendix B to this Subpart or whose specification or tensile properties are unknown, the yield strength to be used in the design formula is §905 is one of the following: [49 CFR 192.107(b)]

1. if the pipe is tensile tested in accordance with Section II-D of §5103, Appendix B to this Subpart, the lower of the following: [49 CFR 192.107(b)(1)]

a. 80 percent of the average yield strength determined by the tensile tests: [49 CFR 192.107(b)(1)(i)]

b. the lowest yield strength determined by the tensile tests; [49 CFR 192.107(b)(1)(ii)]

2. if the pipe is not tensile tested as provided in Paragraph B.1 of this Section, 24,000 psi (165 MPa). [49 CFR 192.107(b)(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 9:221 (April 1983), amended LR 10:513 (July 1984), LR 30:1230 (June 2004).

§909. Nominal Wall Thickness (t) for Steel Pipe [49 CFR 192.109]

A. If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end. [49 CFR 192.109(a)]

B. However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in §905 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter. [49 CFR 192.109(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 9:221 (April 1983), amended LR 10:513 (July 1984), LR 27:1537 (September 2001), LR 30:1230 (June 2004).

§911. Design Factor (F) for Steel Pipe [49 CFR 192.111]

A. Except as otherwise provided in Subsections B, C, and D of this Section, the design factor to be used in the design formula in §905 is determined in accordance with the following table. [49 CFR 192.111(a)]

Class Location	Design Factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

B. A design factor of 0.60 or less must be used in the design formula in §905 for steel pipe in Class 1 locations that: [49 CFR 192.111(b)]

1. crosses the right-of-way of an unimproved public road, without a casing; [49 CFR 192.111(b)(1)]

2. crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad; [49 CFR 192.111(b)(2)]

3. is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or [49 CFR 192.111(b)(3)]

4. is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly. [49 CFR 192.111(b)(4)]

C. For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §905 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad. [49 CFR 192.111(c)]

D. For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §905 for: [49 CFR 192.111(d)]

1. steel pipe in a compressor station, regulating station, or measuring station; and [49 CFR 192.111(d)(1)]

2. steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters. [49 CFR 192.111(d)(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 10:513 (July 1984), LR 30:1230 (June 2004).

§912. Additional Design Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. [49 CFR 192.112]

A. For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure (MAOP) calculated under §2720, a segment must meet the following additional design requirements. Records for alternative MAOP must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements: [49 CFR 192.112]

1. To address this design issue (a-h): The pipeline segment must meet these additional requirements: [49 CFR 192.112]

a. general standards for the steel pipe. [49 CFR 192.112(a)]

i. The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment. [49 CFR 192.112(a)(1)]

ii. The carbon equivalents of the steel used for pipe must not exceed 0.25 percent by weight, as calculated by the Ito-Bessyo formula (Pcm formula) or 0.43 percent by weight, as calculated by the International Institute of Welding (IIW) formula. [49 CFR 192.112(a)(2)]

iii. The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness or other mitigative measures must prevent denting and ovality anomalies during construction, strength testing and anticipated operational stresses. [49 CFR 192.112(a)(3)]

iv. The pipe must be manufactured using API Spec 5L, product specification level 2 (incorporated by reference, see §507) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this Section. [49 CFR 192.112(a)(4)]

b. Fracture control. [49 CFR 192.112(b)]

i. The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with: [49 CFR 192.112(b)(1)]

(a). API Spec 5L (incorporated by reference, see §507); or [49 CFR 192.112(b)(1)(i)]

(b). American Society of Mechanical Engineers (ASME) B31.8 (incorporated by reference, see §507); and [49 CFR 192.112(b)(1)(ii)]

(c). Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Spec 5L, product specification level 2 or ASME B31.8 (incorporated by reference, see §507). [49 CFR 192.112(b)(1)(iii)]

ii. Fracture control must: [49 CFR 192.112(b)(2)]

(a). Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline; [49 CFR 192.112(b)(2)(i)]

(b). Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters; [49 CFR 192.112(b)(2)(ii)]

(c). Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths; and [49 CFR 192.112(b)(2)(iii)]

(d). Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Spec 5L (incorporated by reference, see §507) and ensures ductile fracture and arrest with the following exceptions: [49 CFR 192.112(b)(2)(iv)]

(i). The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent minimum shear area for any single test on each heat of steel; and [49 CFR 192.112(b)(2)(iv)(A)]

(ii). The results of the drop weight test prescribed in SR6 must indicate 80 percent average shear area with a minimum single test result of 60 percent shear area for any steel test samples. The test results must ensure a ductile fracture and arrest. [49 CFR 192.112(b)(2)(iv)(B)]

(iii). If it is not physically possible to achieve the pipeline toughness properties of Clause b.i and b.ii of this section, additional design features, such as mechanical or composite crack arrestors and/or heavier walled pipe of proper design and spacing, must be used to ensure fracture arrest as described in Subclause b.ii.c of this Section. [49 CFR 192.112(b)(3)]

c. Plate/coil quality control. [49 CFR 192.112(c)]

i. There must be an internal quality management program at all mills involved in producing steel, plate, coil, skelp, and/or rolling pipe to be operated at alternative MAOP. These programs must be structured to eliminate or detect defects and inclusions affecting pipe quality. [49 CFR 192.112(c)(1)]

ii. A mill inspection program or internal quality management program must include (a) and either (b) or (c): [49 CFR 192.112(c)(2)]

(a). An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after December 22, 2008, the test must be done in accordance with ASTM A578/A578M Level B, or API Spec 5L paragraph 7.8.10 (incorporated by reference, see §507) or equivalent method, and either [49 CFR 192.112(c)(2)(i)]

(b). A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on the first or second slab of each sequence graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent; or [49 CFR 192.112(c)(2)(ii)]

(c). A quality assurance monitoring program implemented by the operator that includes audits of: [49 CFR 192.112(c)(2)(iii)]

(i). all steelmaking and casting facilities, [49 CFR 192.112(c)(2)(iii)(a)]

(ii). quality control plans and manufacturing procedure specifications, [49 CFR 192.112(c)(2)(iii)(b)]

(iii). equipment maintenance and records of conformance, [49 CFR 192.112(c)(2)(iii)(c)]

(iv). applicable casting superheat and speeds, and [49 CFR 192.112(c)(2)(iii)(d)]

(v). centerline segregation monitoring records to ensure mitigation of centerline segregation during the continuous casting process. [49 CFR 192.112(c)(2)(iii)(e)]

d. Seam quality control. [49 CFR 192.112(d)]

i. There must be a quality assurance program for pipe seam welds to assure tensile strength provided in API Spec 5L (incorporated by reference, see §507) for appropriate grades. [49 CFR 192.112(d)(1)]

ii. There must be a hardness test, using Vickers (Hv10) hardness test method or equivalent test method, to assure a maximum hardness of 280 Vickers of the following: [49 CFR 192.112(d)(2)]

(a). A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and [49 CFR 192.112(d)(2)(i)] (b). For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal). [49 CFR 192.112(d)(2)(ii)]

iii. All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing. [49 CFR 192.112(d)(3)]

e. Mill hydrostatic test. [49 CFR 192.112(e)]

i. All pipe to be used in a new pipeline segment installed after October 1, 2015, must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds (incorporated by reference, see §507). [49 CFR 192.112(e)(1)]

ii. Pipe in operation prior to December 22, 2008, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds. [49 CFR 192.112(e)(2)]

iii. Pipe in operation on or after December 22, 2008, but before October 1, 2015, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. The test pressure may include a combination of internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by "ANSI/API Spec 5L" (incorporated by reference, see §507). [49 CFR 192.112(e)(3)]

f. Coating. [49 CFR 192.112(f)]

i. The pipe must be protected against external corrosion by a non-shielding coating. [49 CFR 192.112(f)(1)]

ii. Coating on pipe used for trenchless installation must be non- shielding and resist abrasions and other damage possible during installation. [49 CFR 192.112(f)(2)]

iii. A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair. [49 CFR 192.112(f)(3)]

g. Fittings and flanges. [49 CFR 192.112(g)]

i. There must be certification records of flanges, factory induction bends and factory weld ells. Certification must address material properties such as chemistry, minimum yield strength and minimum wall thickness to meet design conditions. [49 CFR 192.112(g)(1)]

ii. If the carbon equivalents of flanges, bends and ells are greater than 0.42 percent by weight, the qualified welding procedures must include a pre-heat procedure. [49 CFR 192.112(g)(2)]

iii. Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP. [49 CFR 192.112(g)(3)]

h. Compressor stations. [49 CFR 192.112(h)]

i. A compressor station must be designed to limit the temperature of the nearest downstream segment operating at alternative MAOP to a maximum of 120 degrees Fahrenheit (49 degrees Celsius) or the higher temperature allowed in Clause h.ii of this Section unless a long-term coating integrity monitoring program is implemented in accordance with Clause h.iii of this Section. [49 CFR 192.112(h)(1)]

ii. If research, testing and field monitoring tests demonstrate that the coating type being used will withstand a higher temperature in long-term operations, the compressor station may be designed to limit downstream piping to that higher temperature. Test results and acceptance criteria addressing coating adhesion, cathodic disbondment, and coating condition must be provided to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operating above 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state. [49 CFR 192.112(h)(2)]

iii. Pipeline segments operating at alternative MAOP may operate at temperatures above 120 degrees Fahrenheit (49 degrees Celsius) if the operator implements a long-term coating integrity monitoring program. The monitoring program must include examinations using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or an equivalent method of monitoring coating integrity. An operator must specify the periodicity at which these examinations occur and criteria for repairing identified indications. An operator must submit its long-term coating integrity monitoring program to each PHMSA pipeline safety regional office in which the pipeline is located for review before the pipeline segments may be operated at temperatures in excess of 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state. [49 CFR 192.112(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 35:2802 (December 2009), amended LR 38:115 (January 2012), LR 44:1036 (June 2018).

§913. Longitudinal Joint Factor (E) for Steel Pipe [49 CFR 192.113]

A. The longitudinal joint factor to be used in the design formula in §905 is determined in accordance with the following table.

Specification	Pipe Class	Longitudinal Joint Factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric fusion welded	1.00
ASTM A 672	Electric fusion welded	1.00
ASTM A 691	Electric fusion welded	1.00
API Spec 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
Other	Pipe over 4 inches (102 millimeters)	.80
Other	Pipe 4 inches (102 millimeters) or less	.60

B. If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other." [49 CFR 192.113]

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 10:514 (July 1984), LR 18:855 (August 1992), LR 20:444 (April 1994), LR 27:1538 (September 2001), LR 30:1231 (June 2004), LR 31:681 (March 2005), LR 44:1036 (June 2018).

§915. Temperature Derating Factor (T) for Steel Pipe [49 CFR 192.115]

A. The temperature derating factor to be used in the design formula in §905 is determined as follows.

Gas Temperature in Degrees Fahrenheit (Celsius)	Temperature Derating Factor (T)
250°F (121°C) or less	1.000
300°F (149°C)	0.967
350°F (177°C)	0.933
400° F (204°C)	0.900
450°F (232°C)	0.867

B. For intermediate gas temperatures, the derating factor is determined by interpolation. [49 CFR 192.115]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:222 (April 1983), amended LR 10:514 (July 1984), LR 20:444 (April 1994), LR 27:1538 (September 2001), LR 30:1231 (June 2004).

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

A. Design Pressure. The design pressure for plastic pipe is determined in accordance with either of the following formulas.

$$P = 2S\frac{t}{D-t}(DF)$$

$$P = \frac{2S}{(SDR-1)}(DF)$$

where:

P = Design pressure, gauge, psig (kPa)

S = For thermoplastic pipe, the HDB is determined in accordance with the listed specification at a temperature equal to 73 ºF (23ºC), 100ºF (38ºC), 120ºF (49ºC), or 140ºF (60ºC). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2012, HDB/PDB/SDB/MRS Policies", (incorporated by reference, see §507). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa).

t = Specified wall thickness, in. (mm)

D = Specified outside diameter, in (mm)

SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

DF = Design Factor, a maximum of 0.32 unless otherwise specified for a particular material in this Section. [49 CFR 192.121(a)]

B. General Requirements for Plastic Pipe and Components [49 CFR 192.121(b)]

1. Except as provided in Subsections C through F of this Section, the design pressure for plastic pipe may not exceed a gauge pressure of 100 psig (689 kPa) for pipe used in: [49 CFR 192.121(b)(1)]

a. distribution systems; or [49 CFR 192.121(b)(1)(i)]

b. transmission lines in Class 3 and 4 locations [49 CFR 192.121(b)(1)(ii)]

2. Plastic pipe may not be used where operating temperatures of the pipe will be: [49 CFR 192.121(b)(2)]

a. below -20°F (-29°C), or -40°F (-40°C) if all pipe and pipeline components whose operating temperature will be below -20°F (-29°C) have a temperature rating by the manufacturer consistent with that operating temperature; or [49 CFR 192.121(b)(2)(i)]

b. above the temperature at which HBD used in the design formula under this Section is determined. [49 CFR 192.121(b)(2)(ii)]

3. Unless specified for a particular material in this Section, the wall thickness for thermoplastic pipe may not be less than 0.062 in. (1.57 millimeters). [49 CFR 192.121(b)(3)]

4. All plastic pipe must have a listed HDB in accordance with PPI TR-4/2012). (incorporated by reference, see §507) [49 CFR 192.121(b)(4)]

C. Polyethylene (PE) Pipe Requirements [49 CFR 192.121(c)]

1. For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided: [49 CFR 192.121(c)(1)]

a. The material designation code is PE2406 or PE3408. [49 CFR 192.121(c)(1)(i)]

b. The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and [49 CFR 192.121(c)(1)(ii)]

c. The wall thickness is not less than 0.062 inches (1.57 millimeters). [49 CFR 192.121(c)(1)(iii)]

2. For PE pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided: [49 CFR 192.121(c)(2)]

a. the design pressure does not exceed 125 psig; [49 CFR 192.121(c)(2)(i)]

b. the material designation code is PE2708 or PE4710; [49 CFR 192.121(c)(2)(ii)]

c. the pipe has a nominal size (IPS or CTS) of 24 inches or less; and [49 CFR 192.121(c)(2)(iii)]

d. the wall thickness for a given outside diameter is not less than that listed in Table 1 to this Subparagraph C.2.d : [49 CFR 192.121(c)(2)(iv)]

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	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. Polyamide (PA-11) Pipe Requirements [49 CFR 192.121(d)]

1. For PA-11 pipe produced after January 23, 2009, but before January 22, 2019, a DF of 0.40 may be used in the design formula, provided: [49 CFR 192.121(d)(1)]

a. the design pressure does not exceed 200 psig; [49 CFR 192.121(d)(1)(i)]

b. the material designation code is PA32312 or PA32316; [49 CFR 192.121(d)(1)(ii)]

c. the pipe has a nominal size (IPS or CTS) of 4 inches or less; and [49 CFR 192.121(d)(1)(iii)]

d. the pipe has a standard dimension ratio of SDR-11 or less (i.e., thicker wall pipe). [49 CFR 192.121(d)(1)(iv)]

2. For PA-11 pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided: [49 CFR 192.121(d)(2)]

a. the design pressure does not exceed 250 psig; [49 CFR 192.121(d)(2)(i)]

b. the material designation code is PA32316; [49 CFR 192.121(d)(2)(ii)]

c. the pipe has a nominal size (IPS or CTS) of 6 inches or less; and [49 CFR 192.121(d)(2)(iii)]

d. the minimum wall thickness for a given outside diameter is not less than that listed in Table 2 to Subparagraph D.2.d . [49 CFR 192.121(d)(2)(iv)]

Table 2 to Suparagraph D.2.d
PE Pipe: Minimum Wall Thickness and SDR Values

Pipe Size (inches)	Minimum Wall Thickness	Corresponding SDR (values)
1/2” CTS	0.090	7.0
1/2” IPS	0.090	9.3
3/4” CTS	0.090	9.7
3/4” IPS	0.095	11
1” CTS	0.119	11
1” IPS	0.119	11
1 1/4 IPS	0.151	11
1 1/2” IPS	0.173	11
2” IPS	0.216	11
3” IPS	0.259	13.5
4” IPS	0.333	13.5
6” IPS	0.491	13.5

E. Polyamide (PA-12) Pipe Requirements [49 CFR 192.121(e)]

1. For PA-12 pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided: [49 CFR 192.121(e)(1)]

a. the design pressure does not exceed 250 psig; [49 CFR 192.121(e)(1)(i)]

b. the material designation code is PA42316; [49 CFR 192.121(e)(1)(ii)]

c. the pipe has a nominal size (IPS or CTS) of 6 inches or less; and [49 CFR 192.121(e)(1)(iii)]

d. the minimum wall thickness for a given outside diameter is not less than that listed in Table 3 to Subparagraph E.1.d [49 CFR 192.121(e)(1)(iv)]

Table 3 to Subparagraph E.1.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	11
1” IPS	0.119	11
1 1/4” IPS	0.151	11

Table 3 to Subparagraph E.1.d PE Pipe: Minimum Wall Thickness and SDR Values		
Pipe Size (inches)	Minimum Wall Thickness	Corresponding SDR (values)
1 1/2" IPS	0.173	11
2" IPS	0.216	11
3" IPS	0.259	13.5
4" IPS	0.333	13.5
6" IPS	0.491	13.5

F. Reinforced Thermosetting Plastic Pipe Requirements [49 CFR 192.121(f)]

1. Reinforced thermosetting plastic pipe may not be used at operating temperatures above 150 °F (66 °C). [49 CFR 192.121(f)(1)]

2. The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table. [49 CFR 192.121(f)(2)]

Nominal Size in Inches (Millimeters)	Minimum Wall Thickness Inches (Millimeters)
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

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).

§925. Design of Copper Pipe [49 CFR 192.125]

A. Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn. [49 CFR 192.125(a)]

B. Copper pipe used in service lines must have wall thickness not less than that indicated in the following table. [49 CFR 192.125(b)]

Standard Size Inch (millimeter)	Nominal O.D. Inch (millimeter)	Wall Thickness Inch (millimeter)	
		Nominal	Tolerance
1/2 (13)	.625 (16)	0.040 (1.06)	0.0035 (0.0889)
5/8 (16)	.750 (19)	0.042 (1.07)	0.0035 (0.0889)
3/4 (19)	.875 (22)	0.045 (1.14)	0.004 (0.102)
1 (25)	1.125 (29)	0.050 (1.27)	0.004 (0.102)
1 1/4 (32)	1.375 (35)	0.055 (1.40)	0.0045 (0.1143)
1 1/2 (38)	1.625 (41)	0.060 (1.52)	0.0045 (0.1143)

C. Copper pipe used in mains and service lines may not be used at pressures in excess of 100 psi (689 kPa) gauge. [49 CFR 192.125(c)]

D. Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft^3 ($6.9/m^3$) under standard conditions. Standard conditions refers to 60ºF and 14.7 psia (15.6ºC and one atmosphere) of gas. [49 CFR 192.125(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 9:223 (April 1983), amended LR 10:515 (July 1984), LR 18:855 (August 1992), LR 27:1539 (September 2001), LR 30:1232 (June 2004).

§927. Records: Pipe Design [49 CFR 192.127]

A. For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with §903 and documenting that the determination of design pressure for the pipe is made in accordance with §905 [49 CFR 192.127(a)]

B. For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with §§903 and 905, operators must retain such records for the life of the pipeline. [49 CFR 192.127(b)]

C. For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §2724 according to the terms of that Section. [49 CFR 192.127(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 46:1584 (November 2020).

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

§1101. Scope [49 CFR 192.141]

A. This Chapter prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring. [49 CFR 192.141]

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 10:515 (July 1984), LR 30:1232 (June 2004).

§1103. General Requirements [49 CFR 192.143]

A. Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component. [49 CFR 192.143(a)]

B. The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in Chapter 21 of this Subpart. [49 CFR 192.143(b)]

C. Except for excess flow valves, each plastic pipeline component installed after January 22, 2019 must be able to withstand operating pressures and other anticipated loads in accordance with a listed specification. [49 CFR 192.143(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 9:223 (April 1983), amended LR 10:515 (July 1984), LR 30:1232 (June 2004), LR 35:2805 (December 2009), LR 46:1584 (November 2020)

§1104. Qualifying Metallic Components [49 CFR 192.144]

A. Notwithstanding any requirement of this Chapter which incorporates by reference an edition of a document listed in §507 or §5103 of this Subpart, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this Subpart if [49 CFR 192.144]:

1. it can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and [49 CFR 192.144(a)]

2. the edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §507 or §5103 of this Subpart [49 CFR 192.144(b)]:

a. pressure testing; [49 CFR 192.144(b)(1)]

b. materials; and [49 CFR 192.144(b)(2)]

c. pressure and temperature ratings. [49 CFR 192.144(b)(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, amended LR 10:515 (July 1984), LR 30:1232 (June 2004), LR31:682 (March 2005), LR 33:478 (March 2007).

§1105. Valves [49 CFR 192.145]

A. Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, see §507), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements [49 CFR 192.145(a)].

B. Each cast iron and plastic valve must comply with the following. [49 CFR 192.145(b)]

1. The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature. [49 CFR 192.145(b)(1)]

2. The valve must be tested as part of the manufacturing, as follows. [49 CFR 192.145(b)(2)]

a. With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating. [49 CFR 192.145(b)(2)(i)]

b. After the shell test, the seat must be tested to a pressure no less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted. [49 CFR 192.145(b)(2)(ii)]

c. After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference. [49 CFR 192.145(b)(2)(iii)]

C. Each valve must be able to meet the anticipated operating conditions. [49 CFR 192.145(c)]

D. No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if: [49 CFR 192.145(d)]

1. the temperature-adjusted service pressure does not exceed 1,000 psi (7 MPa) gauge; and [49 CFR 192.145(d)(1)]

2. welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly. [49 CFR 192.145(d)(2)]

E. No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations. [49 CFR 192.145(e)]

F. Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of a listed specification. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification. [49 CFR 192.145(f)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:223 (April 1983), amended LR 10:515 (July 1984), LR 18:855 (August 1992), LR 27:1539 (September 2001), LR 30:1232 (June 2004), LR 31:682 (March 2005), LR 33:479 (March 2007), LR 38:115 (January 2012), LR 44:1037 (June 2018), LR 46:1584 (November 2020).

§1107. Flanges and Flange Accessories [49 CFR 192.147]

A. Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5 and MSS SP 44. (incorporated by reference, see §507). [49 CFR 192.147(a)]

B. Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service. [49 CFR 192.147(b)]

C. Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, see §507) and be cast integrally with the pipe, valve, or fitting. [49 CFR 192.147(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 9:223 (April 1983), amended LR 10:515 (July 1984), LR 18:856 (August 1992), LR 20:444 (April 1994), LR 30:1233 (June 2004), LR 44:1037 (June 2018).

§1109. Standard Fittings [49 CFR 192.149]

A. The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in Part XIII, or their equivalent. [49 CFR 192.149(a)]

B. Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added. [49 CFR 192.149(b)]

C. Plastic fittings installed after January 22, 2019, must meet a listed specification. [49 CFR 192.149(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 9:223 (April 1983), amended LR 10:515 (July 1984), LR 30:1233 (June 2004), LR 46:1584 (November 2020).

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

A. Except as provided in Subsections B and C of this Section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line, must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, see §507). [49 CFR 192.150(a)].

B. This Section does not apply to: [49 CFR 192.150(b)]

1. manifolds; [49 CFR 192.150(b)(1)

2. station piping such as at compressor stations, meter stations, or regulator stations; [49 CFR 192.150(b)(2)]

3. piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities; [49 CFR 192.150(b)(3)]

4. cross-overs; [49 CFR 192.150(b)(4)]

5. sizes of pipe for which an instrumented internal inspection devise is not commercially available; [49 CFR 192.150(b)(5)]

6. transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations; [49 CFR 192.150(b)(6)]

7. offshore transmission lines, except transmission lines 10 3/4 inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless [49 CFR 192.150(b)(7)]:

a. platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or [49 CFR 192.150(b)(7)(i)]

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. 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)]

C. An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet Subsection A of this Section, if the operator determines and documents why an impracticability prohibits compliance with Subsection A of this Section. Within 30 days after discovering the emergency or construction problem the operator must petition, under 49 CFR Part 190.9 and LAC 43:XI.Subpart 3 for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within one year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices. [49 CFR 192.150(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).

§1111. Tapping [49 CFR 192.151]

A. Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline. [49 CFR 192.151(a)]

B. Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions. [49 CFR 192.151(b)]

C. Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that: [49 CFR 192.151(c)]

1. existing taps may be used for replacement service, if they are free of cracks and have good threads; and [49 CFR 192.151(c)(1)]

2. a 1 1/4 inch (32 millimeters) tap may be made in a 4 inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement. [49 CFR 192.151(c)(2)]

D. However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6 inch (152 millimeters) or larger pipe.

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 10:515 (July 1984), LR 27:1539 (September 2001), LR 30:1234 (June 2004).

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

A. Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with Paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see §507). [49 CFR 192.153(a)]

B. Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with the ASME BPVC (*Rules for Construction of Pressure Vessels* as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, see §507), except for the following: [49 CFR 192.153(b)]

1. regularly manufactured butt-welding fittings; [49 CFR 192.153(b)(1)]

2. pipe that has been produced and tested under a specification listed in §5103, Appendix B to this Subpart; [49 CFR 192.153(b)(2)]

3. partial assemblies such as split rings or collars; [49 CFR 192.153(b)(3)]

4. prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions. [49 CFR 192.153(b)(4)]

C. Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe. [49 CFR 192.153(c)]

D. Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2), flat closures and fish tails may not be used on pipe that either operates at 100 psi (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter. [49 CFR 192.153(d)]

E. The test requirements for a prefabricated unit or pressure vessel, defined for this Subsection as components with a design pressure established in accordance with Subsection A or Subsection B of this Section are as follows. [49 CFR 192.153(e)]

1. prefabricated unit or pressure vessel installed after July 14, 2004 is not subject to the strength testing requirements at §2305.B provided the component has been tested in accordance with Subsection A or Subsection B of this Section and with a test factor of at least 1.3 times MAOP. [49 CFR 192.153(e)(1)]

2. A prefabricated unit or pressure vessel must be tested for a duration specified as follows: [49 CFR 192.153(e)(2)]

a. A prefabricated unit or pressure vessel installed after July 14, 2004, but before October 1, 2021 is exempt from §§2305.C and D and 2307.C provided it has been tested for a duration consistent with the ASME BPVC requirements referenced in Subsection A or B of this Section. [49 CFR 192.153(e)(2)(i)]

b. b.

Consider the information gained from past design, operations, and maintenance. [49 CFR 192.153(e)(2)(ii)]

3. For any prefabricated unit or pressure vessel permanently or temporarily installed on a pipeline facility, an operator must either: [49 CFR 192.153(e)(3)]

a. Test the prefabricated unit or pressure vessel in accordance with this Section and Chapter 23 of this Subpart after it has been placed on its support structure at its final installation location. The test may be performed before or after it has been tied-in to the pipeline. Test records that meet §2317.A must be kept for the operational life of the prefabricated unit or pressure vessel; or [49 CFR 192.153(e)(3)(i)]

b. For a prefabricated unit or pressure vessel that is pressure tested prior to installation or where a manufacturer's pressure test is used in accordance with Subsection E of this Section, inspect the prefabricated unit or pressure vessel after it has been placed on its support structure at its final installation location and confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection procedure and documented inspection must include visual inspection for vessel damage, including, at a minimum, inlets, outlets, and lifting locations. Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. This inspection must be performed prior to operation but may be performed either before or after it has been tied-in to the pipeline. If injurious defects that are an integrity threat are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with applicable Subpart 3(Part 192) requirements for a fabricated unit or with the applicable ASME BPVC requirements referenced in Subsections A or B of this Section. Test, inspection, and repair records for the fabricated unit or pressure vessel must be kept for the operational life of the component. Test records must meet the requirements in §2317.A. [49 CFR 192.153(e)(3)(ii)]

4. An initial pressure test from the prefabricated unit or pressure vessel manufacturer may be used to meet the requirements of this Section with the following conditions: [49 CFR 192.153(e)(4)]

a. The prefabricated unit or pressure vessel is newly-manufactured and installed on or after October 1, 2021, except as provided in Subparagraph E.4.b of this Section. [49 CFR 192.153(e)(4)(i)]

b. An initial pressure test from the fabricated unit or pressure vessel manufacturer or other prior test of a new or existing prefabricated unit or pressure vessel may be used for a component that is temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. The temporary component must be promptly removed after that task is completed. If operational and environmental constraints require leaving a temporary prefabricated unit or pressure vessel under this Subsection in place for longer than 30 days, the operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with § 518. [49 CFR 192.153(e)(4)(ii)]

c. The manufacturer's pressure test must meet the minimum requirements of this Subpart; and [49 CFR 192.153(e)(4)(iii)]

d. The operator inspects and remediates the prefabricated unit or pressure vessel after installation in accordance with Subparagraph E.3.b of this Section. [49 CFR 192.153(e)(4)(iv)]

5. An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement, and then re-installed at the same location must be inspected in accordance with Subparagraph E.3.b of this Section; however, a new pressure test is not required provided no damage or threats to the operational integrity of the prefabricated unit or pressure vessel were identified during the inspection and the MAOP of the pipeline is not increased. [49 CFR 192.153(e)(5)]

6. Except as provided in Subparagraphs E.4.b and Paragraph E.5 of this Section, on or after October 1, 2021, an existing prefabricated unit or pressure vessel relocated and operated at a different location must meet the requirements of this Subpart and the following: [49 CFR 192.153(e)(6)]

a. The prefabricated unit or pressure vessel must be designed and constructed in accordance with the requirements of this Subpart at the time the vessel is returned to operational service at the new location; and [49 CFR 192.153(e)(6)(i)]

b. The prefabricated unit or pressure vessel must be pressure tested by the operator in accordance with the testing and inspection requirements of this Subpart applicable to newly installed prefabricated units and pressure vessels. [49 CFR 192.153(e)(6)(ii)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, 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 47:1142 (August 2021) repromulgated LR 47:1331 (September 2021).

§1115. Welded Branch Connections [49 CFR 192.155]

A. Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration. [49 CFR 192.155]

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 9:224 (April 1983), amended LR 10:516 (July 1984), LR 30:1234 (June 2004).

§1117. Extruded Outlets [49 CFR 192.157]

A. Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached. [49 CFR 192.157]

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 9:224 (April 1983), amended LR 10:516 (July 1984), LR 30:1234 (June 2004).

§1119. Flexibility [49 CFR 192.159]

A. Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points. [49 CFR 192.159]

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 9:224 (April 1983), amended LR 10:516 (July 1984), LR 30:1234 (June 2004).

§1121. Supports and Anchors [49 CFR 192.161]

A. Each pipeline and its associated equipment must have enough anchors or supports to: [49 CFR 192.161(a)]

1. prevent undue strain on connected equipment; [49 CFR 192.161(a)(1)]

2. resist longitudinal forces caused by a bend or offset in the pipe; and [49 CFR 192.161(a)(2)]

3. prevent or damp out excessive vibration. [49 CFR 192.161(a)(3)]

B. Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents. [49 CFR 192.161(b)]

C. Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows. [49 CFR 192.161(c)]

1. Free expansion and contraction of the pipeline between supports or anchors may not be restricted. [49 CFR 192.161(c)(1)]

2. Provision must be made for the service conditions involved. [49 CFR 192.161(c)(2)]

3. Movement of the pipeline may not cause disengagement of the support equipment. [49 CFR 192.161(c)(3)]

D. Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following. [49 CFR 192.161(d)]

1. A structural support may not be welded directly to the pipe. [49 CFR 192.161(d)(1)]

2. The support must be provided by a member that completely encircles the pipe. [49 CFR 192.161(d)(2)]

3. If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference. [49 CFR 192.161(d)(3)]

E. Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline. [49 CFR 192.161(e)]

F. Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement. [49 CFR 192.161(f)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:224 (April 1983), amended LR 10:516 (July 1984), LR 30:1234 (June 2004).

§1123. Compressor Stations: Design and Construction [49 CFR 192.163]

A. Location of compressor building. Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment. [49 CFR 192.163(a)]

B. Building Construction. Each building on a compressor station site must be made of noncombustible materials if it contains either: [49 CFR 192.163(b)]

1. pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or [49 CFR 192.163(b)(1)]

2. gas handling equipment other than gas utilization equipment used for domestic purposes. [49 CFR 192.163(b)(2)]

C. Exits. Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward. [49 CFR 192.163(c)]

D. Fenced Areas. Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key. [49 CFR 192.163(d)]

E. Electrical Facilities. Electrical equipment and wiring installed in compressor stations must conform to the NFPA-70, so far as that code is applicable. [49 CFR 192.163(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 9:224 (April 1983), amended LR 10:516 (July 1984), LR 20:445 (April 1994), LR 27:1539 (September 2001), LR 30:1235 (June 2004), LR 44:1037 (June 2018).

§1125. Compressor Stations: Liquid Removal [49 CFR 192.165]

A. Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage. [49 CFR 192.165(a)]

B. Each liquid separator used to remove entrained liquids at a compressor station must: [49 CFR 192.165(b)]

1. have a manually operable means of removing these liquids; [49 CFR 192.165(b)(1)]

2. where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and [49 CFR 192.165(b)(2)]

3. be manufactured in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §507) and the additional requirements of §1113.E except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less. [49 CFR 192.165(b)(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 9:224 (April 1983), amended LR 10:516 (July 1984), LR 30:1235 (June 2004), LR 44:1037 (June 2018).

§1127. Compressor Stations: Emergency Shutdown [49 CFR 192.167]

A. Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following. [49 CFR 192.167(a)]

1. It must be able to block gas out of the station and blow down the station piping. [49 CFR 192.167(a)(1)]

2. It must discharge gas from the blowdown piping at a location where the gas will not create a hazard. [49 CFR 192.167(a)(2)]

3. It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except, that: [49 CFR 192.167(a)(3)]

a. electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and [49 CFR 192.167(a)(3)(i)]

b. electrical circuits needed to protect equipment from damage may remain energized. [49 CFR 192.167(a)(3)(ii)]

4. It must be operable from at least two locations, each of which is: [49 CFR 192.167(a)(4)]

a. outside the gas area of the station; [49 CFR 192.167(a)(4)(i)]

b. near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and [49 CFR 192.167(a)(4)(ii)]

c. not more than 500 feet (153 meters) from the limits of the station. [49 CFR 192.167(a)(4)(iii)]

B. If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shut-down system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system. [49 CFR 192.167(b)]

C. On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events: [49 CFR 192.167(c)]

1. in the case of an unattended compressor station: [49 CFR 192.167(c)(1)]

a. when the gas pressure equals the maximum allowable operating pressure plus 15 percent; or [49 CFR 192.167(c)(1)(i)]

b. when an uncontrolled fire occurs on the platform; and [49 CFR 192.167(c)(1)(ii)]

2. in the case of a compressor station in a building: [49 CFR 192.167(c)(2)]

a. when an uncontrolled fire occurs in the building; or [49 CFR 192.167(c)(2)(i)]

b. when the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition. [49 CFR 192.167(c)(2)(ii)]

D. For the purpose of Subparagraph C.2.b of this Section, an electrical facility which conforms to Class 1, Group D of the National Electrical Code is not a source of ignition. [49 CFR 192.167(c)(2)(ii)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:224 (April 1983), amended LR 10:517 (July 1984), LR 27:1540 (September 2001), LR 30:1235 (June 2004).

§1129. Compressor Stations: Pressure Limiting Devices [49 CFR 192.169]

A. Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent. [49 CFR 192.169(a)]

B. Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard. [49 CFR 192.169(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 9:225 (April 1983), amended LR 10:517 (July 1984), LR 30:1236 (June 2004).

§1131. Compressor Stations: Additional Safety Equipment [49 CFR 192.171]

A. Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system. [49 CFR 192.171(a)]

B. Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed. [49 CFR 192.171(b)]

C. Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit. [49 CFR 192.171(c)]

D. Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold. [49 CFR 192.171(d)]

E. Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler. [49 CFR 192.171(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 9:225 (April 1983), amended LR 10:517 (July 1984), LR 20:445 (April 1994), LR 30:1236 (June 2004).

§1133. Compressor Stations: Ventilation [49 CFR 192.173]

A. Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places. [49 CFR 192.173]

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 10:517 (July 1984), LR 30:1236 (June 2004).

§1135. Pipe-Type and Bottle-Type Holders [49 CFR 192.175]

A. Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder. [49 CFR 192.175(a)]

B. Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula. [49 CFR 192.175(b)]

C = (3D x P x F)/(1000) in inches; (C=(3D x P x F/6,895) in millimeters in which:

C = minimum clearance between pipe containers or bottles in inches (millimeters);
D = outside diameter of pipe containers or bottles in inches (millimeters);
P = maximum allowable operating pressure, psi(kPa) gage;
F = design factor as set forth in §911 of this Subpart.

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 10:517 (July 1984), LR 27:1540 (September 2001), LR 30:1236 (June 2004), LR 44:1038 (June 2018).

§1137. Additional Provisions for Bottle-Type Holders [49 CFR 192.177]

A. Each bottle-type holder must be: [49 CFR 192.177(a)]

1. located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows: [49 CFR 192.177(a)(1)]

Maximum Allowable Operating Pressure	Minimum Clearance Feet (meters)
Less than 1,000 psi(7 Mpa) gauge	25 (7.6)
1,000 psi (7 Mpa) gauge or more	100 (31)

2. designed using the design factors set forth in §911; and [49 CFR 192.177(a)(2)]

3. buried with a minimum cover in accordance with §1727. [49 CFR 192.177(a)(3)]

B. Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following. [49 CFR 192.177(b)]

1. A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/372M (incorporated by reference, see §507). [49 CFR 192.177(b)(1)]

2. The actual yield-tensile ratio of the steel may not exceed 0.85. [49 CFR 192.177(b)(2)]

3. Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermit welding process is used. [49 CFR 192.177(b)(3)]

4. The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS. [49 CFR 192.177(b)(4)]

5. The holder, connection pipe, and components must be leak tested after installation as required by Chapter 23 of this Subpart. [49 CFR 192.177(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, LR 9:225 (April 1983), amended LR 10:517 (July 1984), LR 18:856 (August 1992), LR

20:445 (April 1994), LR 27:1540 (September 2001), LR 30:1237 (June 2004), LR 44:1038 (June 2018).

§1139. Transmission Line Valves [49 CFR 192.179]

A. Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the commissioner/administrator finds that alternative spacing would provide an equivalent level of safety: [49 CFR 192.179(a)]

1. each point on the pipeline in a Class 4 location must be within 2 1/2 miles (4 kilometers) of a valve; [49 CFR 192.179(a)(1)]

2. each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve; [49 CFR 192.179(a)(2)]

3. each point on the pipeline in a Class 2 location must be within 7 1/2 miles (12 kilometers) of a valve; [49 CFR 192.179(a)(3)]

4. each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve. [49 CFR 192.179(a)(4)]

B. Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following. [49 CFR 192.179(b)]

1. The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage. [49 CFR 192.179(b)(1)]

2. The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached. [49 CFR 192.179(b)(2)]

C. Each section of a transmission line, other than offshore segments, between main line valves must have a blow-down valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blow-down discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors. [49 CFR 192.179(c)]

D. Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency. [49 CFR 192.179(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 9:225 (April 1983), amended LR 10:518 (July 1984), LR 24:1308 (July 1998), LR 27:1540 (September 2001), LR 30:1237 (June 2004).

§1141. Distribution Line Valves [49 CFR 192.181]

A. Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions. [49 CFR 192.181(a)]

B. Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station. [49 CFR 192.181(b)]

C. Each valve on a main installed for operating or emergency purposes must comply with the following. [49 CFR 192.181(c)]

1. The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency. [49 CFR 192.181(c)(1)]

2. The operating stem or mechanism must be readily accessible. [49 CFR 192.181(c)(2)]

3. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main. [49 CFR 192.181(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 9:225 (April 1983), amended LR 10:518 (July 1984), LR 30:1237 (June 2004).

§1143. Vaults: Structural Design Requirements [49 CFR 192.183]

A. Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment. [49 CFR 192.183(a)]

B. There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained. [49 CFR 192.183(b)]

C. Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inches (254 millimeters), and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe. [49 CFR 192.183(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 9:226 (April 1983), amended LR 10:518 (July 1984), LR 27:1540 (September 2001), LR 30:1238 (June 2004), LR 35:2805 (December 2009).

§1145. Vaults: Accessibility [49 CFR 192.185]

A. Each vault must be located in an accessible location and, so far as practical, away from: [49 CFR 192.185]

1. street intersections or points where traffic is heavy or dense; [49 CFR 192.185(a)]

2. points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and [49 CFR 192.185(b)]

3. water, electric, steam, or other facilities. [49 CFR 192.185(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 9:226 (April 1983), amended LR 10:518 (July 1984), LR 30:1238 (June 2004).

§1147. Vaults: Sealing, Venting, and Ventilation [49 CFR 192.187]

A. Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated, as follows. [49 CFR 192.187]

1. When the internal volume exceeds 200 cubic feet (5.7 cubic meters): [49 CFR 192.187(a)]

a. the vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter; [49 CFR 192.187(a)(1)]

b. the ventilation must be enough to minimize the formulation of combustible atmosphere in the vault or pit; and [49 CFR 192.187(a)(2)]

c. the ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged. [49 CFR 192.187(a)(3)]

2. When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters): [49 CFR 192.187(b)]

a. if the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover; [49 CFR 192.187(b)(1)]

b. if the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or [49 CFR 192.187(b)(2)]

c. if the vault or pit is ventilated, Paragraphs 1 or 3 of this Subsection applies. [49 CFR 192.187(b)(3)]

3. If a vault or pit covered by Paragraph 2 of this Subsection is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required. [49 CFR 192.187(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 9:226 (April 1983), amended LR 10:518 (July 1984), LR 27:1540 (September 2001), LR 30:1238 (June 2004).

§1149. Vaults: Drainage and Waterproofing [49 CFR 192.189]

A. Each vault must be designated so as to minimize the entrance of water. [49 CFR 192.189(a)]

B. A vault containing gas piping may not be connected by means of a drain connection to any other underground structure. [49 CFR 192.189(b)]

C. Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA-70 (incorporated by reference, see §507). [49 CFR 192.189(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 9:226 (April 1983), amended LR 10:518 (July 1984), LR 24:1309 (July 1998), LR 30:1238 (June 2004), LR 44:1038 (June 2018).

§1153. Valve Installation in Plastic Pipe [49 CFR 192.193]

A. Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure. [49 CFR 192.193]

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 9:227 (April 1983), amended LR 10:519 (July 1984), LR 30:1238 (June 2004).

§1155. Protection against Accidental Overpressuring [49 CFR 192.195]

A. General Requirements. Except as provided in §1157, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§1159 and 1161. [49 CFR 192.195(a)]

B. Additional Requirements for Distribution Systems. Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must: [49 CFR 192.195(b)]

1. have pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and [49 CFR 192.195(b)(1)]

2. be designed so as to prevent accidental overpressuring. [49 CFR 192.195(b)(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 9:227 (April 1983), amended LR 10:519 (July 1984), LR 30:1239 (June 2004).

§1157. Control of the Pressure of Gas Delivered from High-Pressure Distribution Systems [49 CFR 192.197]

A. If the maximum actual operating pressure of the distribution system is 60 psi (414 kPa) gage, or less, and a service regulator having the following characteristics is used, no other pressure limiting device is required: [49 CFR 192.197(a)]

1. a regulator capable of reducing distribution line pressure to pressures recommended for household appliances; [49 CFR 192.197(a)(1)]

2. a single port valve with proper orifice for the maximum gas pressure at the regulator inlet; [49 CFR 192.197(a)(2)]

3. a valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port; [49 CFR 192.197(a)(3)]

4. pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter; [49 CFR 192.197(a)(4)]

5. a regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the buildup of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment; [49 CFR 192.197(a)(5)]

6. a self-contained service regulator with no external static or control lines. [49 CFR 192.197(a)(6)]

B. If the maximum actual operating pressure of the distribution system is 60 psi (414 kPa) gage or less, and a service regulator that does not have all of the characteristics listed in Subsection A of this Section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails. [49 CFR 192.197(b)]

C. If the maximum actual operating pressure of the distribution system exceeds 60 psi (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer: [49 CFR 192.197(c)]

1. a service regulator having the characteristics listed in Subsection A of this Section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 psi (414 kPa) gage. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gage or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if the pressure on the inlet of the service regulator exceeds the set pressure [60 psi (414 kPa) gage or less], and remains closed until manually reset; [49 CFR 192.197(c)(1)]

2. a service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer; [49 CFR 192.197(c)(2)]

3. a service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 psi (862 kPa) gage. For higher inlet pressure, the methods in Paragraphs 1 or 2 of this Subsection must be used; [49 CFR 192.197(c)(3)]

4. a service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset. [49 CFR 192.197(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 9:227 (April 1983), amended LR 10:519 (July 1984), LR 18:856 (August 1992), LR 27:1541 (September 2001), LR 30:1239 (June 2004).

§1159. Requirements for Design of Pressure Relief and Limiting Devices [49 CFR 192.199]

A. Except for rupture discs, each pressure relief or pressure limiting device must: [49 CFR 192.199]

1. be constructed of materials such that the operation of a device will not be impaired by corrosion; [49 CFR 192.199(a)]

2. have valves and valve seats that are designed not to stick in a position that will make the device inoperative; [49 CFR 192.199(b)]

3. be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position; [49 CFR 192.199(c)]

4. have support made of noncombustible material; [49 CFR 192.199(d)]

5. have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard; [49 CFR 192.199(e)]

6. be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity; [49 CFR 192.199(f)]

7. where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and [49 CFR 192.199(g)]

8. except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative. [49 CFR 192.199(h)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:227 (April 1983), amended LR 10:520 (July 1984), LR 30:1239 (June 2004).

§1161. Required Capacity of Pressure Relieving and Limiting Stations [49 CFR 192.201]

A. Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following: [49 CFR 192.201(a)]

1. in a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment; [49 CFR 192.201(a)(1)]

2. in pipelines other than a low pressure distribution system: [49 CFR 192.201(a)(2)]

a. if the maximum allowable operating pressure is 60 psi (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower; [49 CFR 192.201(a)(2)(i)]

b. if the maximum allowable operating pressure is 12 psi (83 kPa) gage or more, but less than 60 psi (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 psi (41 kPa) gage; or [49 CFR 192.201(a)(2)(ii)]

c. if the maximum allowable operating pressure is less than 12 psi (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent. [49 CFR 192.201(a)(2)(iii)]

B. When more than one pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower. [49 CFR 192.201(b)]

C. Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment. [49 CFR 192.201(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 9:228 (April 1983), amended LR 10:520 (July 1984), LR 27:1541 (September 2001), LR 30:1240 (June 2004).

§1163. Instrument, Control, and Sampling Pipe and Components [49 CFR 192.203]

A. Applicability. This Section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices. [49 CFR 192.203(a)]

B. Materials and Design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following. [49 CFR 192.203(b)]

1. Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue. [49 CFR 192.203(b)(1)]

2. Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary. [49 CFR 192.203(b)(2)]

3. Brass or copper material may not be used for metal temperatures greater than 400°F (204°C). [49 CFR 192.203(b)(3)]

4. Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing. [49 CFR 192.203(b)(4)]

5. Pipe or components in which liquids may accumulate must have drains or drips. [49 CFR 192.203(b)(5)]

6. Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning. [49 CFR 192.203(b)(6)]

7. The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses. [49 CFR 192.203(b)(7)]

8. Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself. [49 CFR 192.203(b)(8)]

9. Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative. [49 CFR 192.203(b)(9)]

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 9:228 (April 1983), amended LR 10:520 (July 1984), LR 20:445 (April 1994), LR 24:1309 (July 1998), LR 27:1541 (September 2001), LR 30:1240 (June 2004).

§1164. Instrument, Control, and Sampling Pipe and Components [49 CFR 192.204]

A. Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly. [49 CFR 192.204(a)]

B. Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973-13 (incorporated by reference, see § 507). [49 CFR 192.204(b)]

C. All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this Section must have a rigid riser casing. [49 CFR 192.204(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 46:1584 (November 2020).

§1165. Records: Pipeline components. [49 CFR 192.205]

A. For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this Subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials. [49 CFR 192.205(a)]

B. For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline. [49 CFR 192.205(b)]

C. For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §2724 according to the terms of that Section. [49 CFR 192.205(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 46:1584 (November 2020).

Chapter 13. Welding of Steel in Pipelines [49 CFR Part 192 Subpart E]

§1301. Scope [49 CFR 192.221]

A. This Chapter prescribes minimum requirements for welding steel materials in pipelines. [49 CFR 192.221(a)]

B. This Chapter does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components. [49 CFR 192.221(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 9:228 (April 1983), amended LR 10:521 (July 1984), LR 30:1241 (June 2004).

§1305. Welding Procedures [49 CFR 192.225]

A. Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, or Appendix A of API Std 1104 (incorporated by reference, see §507) or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see §507) to produce welds meeting the requirements of this Chapter. The quality of the test welds used to qualify welding procedures shall be determined by destructive testing in accordance with the applicable welding standard(s) [49 CFR 192.225(a)].

B. Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used. [49 CFR 192.225(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 9:228 (April 1983), amended LR 10:521 (July 1984), LR 30:1241 (June 2004), LR 31:683 (March 2005), LR 33:479 (March 2007), LR 44:1038 (June 2018).

§1307. Qualification of Welders [49 CFR 192.227]

A. Except as provided in Subsection B of this Section, each welder or welding operator must be qualified in accordance with section 6, section 12, or appendix A of API Std 1104 (incorporated by reference, see §507) or Section IX of the ASME Boiler and Pressure Vessel Code (ASME BPVC) (incorporated by reference, see §507). However, a welder or welding operator qualified under an earlier edition than listed in §507 may weld but may not re-qualify under that earlier edition [49 CFR 192.227(a)].

B. A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in Section I of §5105, Appendix C of this Subpart. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under Section II of §5105. Appendix C of this Subpart as a requirement of the qualifying test. [49 CFR 192.227(b)]

C. For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this Section must be retained for a minimum of five years following construction. [49 CFR 192.227(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 9:229 (April 1983), amended LR 10:521 (July 1984), LR 24:1309 (July 1998), LR 30:1241 (June 2004), LR 31:683 (March 2005), LR 33:479 (March 2007), LR 44:1038 (June 2018), LR 46:1585 (November 2020).

§1309. Limitations on Welders [49 CFR 192.229]

A. No welder whose qualification is based on nondestructive testing may weld compressor station pipe and components. [49 CFR 192.229(a)]

B. A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process. Alternatively, welders or welding operators may demonstrate they have engaged in a specific welding process if they have performed a weld with that process that was tested and found acceptable under section 6, 9, 12, or Appendix A of API Std 1104 (incorporated by reference, *see* §507) within the preceding 7 1/2 months. [49 CFR 192.229(b)]

C. A welder qualified under §1307.A: [49 CFR 192.229(c)]

1. may not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under the sections 6, section 9 or section 12 of API Std 1104 (incorporated by reference, see §507). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7 1/2 months. A welder or welding operator qualified under an earlier edition of a standard listed in §507 of this Subpart may weld but may not re-qualify under that earlier edition [49 CFR 192.229(c)(1)]; and

2. may not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder is tested in accordance with Paragraph C.1 of this Section or requalifies under Paragraph D.1 or D.2 of this Section. [49 CFR 192.229(c)(2)]

D. A welder qualified under §1307.B may not weld unless: [49 CFR 192.229(d)]

1. within the preceding 15 calendar months, but at least once each calendar year, the welder has requalified under §1307.B; or [49 CFR 192.229(d)(1)]

2. within the preceding 7 1/2 calendar months, but at least twice each calendar year, the welder has had: [49 CFR 192.229(d)(2)]

a. a production weld cut out, tested, and found acceptable in accordance with the qualifying test; or [49 CFR 192.229(d)(2)(i)]

b. for a welder who works only on service lines 2 inches (51 millimeters) or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in Section III of §5105, Appendix C of this Subpart. [49 CFR 192.229(d)(2)(ii)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:229 (April 1983), amended LR 10:521 (July 1984), LR 24:1309 (July 1998), LR 27:1541 (September 2001), LR 30:1241 (June 2004), LR 31:683 (March 2005), LR 33:479 (March 2007), LR 44:1038 (June 2018), LR. 47:1143 (August 2021).

§1311. Protection from Weather [49 CFR 192.231]

A. The welding operation must be protected from weather conditions that would impair the quality of the completed weld. [49 CFR 192.231]

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 9:229 (April 1983), amended LR 10:521 (July 1984), LR 30:1241 (June 2004).

§1313. Miter Joints [49 CFR 192.233]

A. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SYMS may not deflect the pipe more than 3°. [49 CFR 192.233(a)]

B. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent of SMYS may not deflect the pipe more than 12 1/2° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint. [49 CFR 192.233(b)]

C. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90°. [49 CFR 192.233(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 9:229 (April 1983), amended LR 10:521 (July 1984), LR 30:1241 (June 2004).

§1315. Preparation for Welding [49 CFR 192.235]

A. Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited. [49 CFR 192.235]

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 9:229 (April 1983), amended LR 10:522 (July 1984), LR 30:1242 (June 2004).

§1321. Inspection and Test of Welds [49 CFR 192.241]

A. Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that [49 CFR 192.241(a)]:

1. the welding is performed in accordance with the welding procedure; and [49 CFR 192.241(a)(1)]

2. the weld is acceptable under Subsection C of this Section. [49 CFR 192.241(a)(2)]

B. The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with §1323, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if: [49 CFR 192.241(b)]

1. the pipe has a nominal diameter of less than 6 inches (152 millimeters); or [49 CFR 192.241(b)(1)]

2. the pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical. [49 CFR 192.241(b)(2)]

C. The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 of API Std 1104 (incorporated by reference, see §507). Appendix A of API Std 1104 may not be used to accept cracks. [49 CFR 192.241(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 9:230 (April 1983), amended LR 10:522 (July 1984), LR 24:1309 (July 1998), LR 27:1541 (September 2001), LR 30:1242 (June 2004), LR 31:683 (March 2005), LR 33:479 (March 2007), LR 44:1039 (June 2018).

§1323. Nondestructive Testing [49 CFR 192.243]

A. Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld. [49 CFR 192.243(a)]

B. Nondestructive testing of welds must be performed: [49 CFR 192.243(b)]

1. in accordance with written procedures; and [49 CFR 192.243(b)(1)]

2. by persons who have been trained and qualified in the established procedures and with the equipment employed in testing. [49 CFR 192.243(b)(2)]

C. Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under §1321.C. [49 CFR 192.243(c)]

D. When nondestructive testing is required under §1321.B, the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference: [49 CFR 192.243(d)]

1. in Class 1 locations, except offshore, at least 10 percent; [49 CFR 192.243(d)(1)]

2. in Class 2 locations, at least 15 percent; [49 CFR 192.243(d)(2)]

3. in Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested; [49 CFR 192.243(d)(3)]

4. at pipeline tie-ins, including tie-ins of replacement sections, 100 percent. [49 CFR 192.243(d)(4)]

E. Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welders or welding operator’s work for each day must be nondestructively tested, when nondestructive testing is required under §1321.B. [49 CFR 192.243(e)]

F. When nondestructive testing is required under §1321.B, each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects. [49 CFR 192.243(f)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:230 (April 1983), amended LR 10:522 (July 1984), LR 24:1309 (July 1998), LR 30:1242 (June 2004), LR 44:1039 (June 2018).

§1325. Repair or Removal of Defects [49 CFR 192.245]

A. Each weld that is unacceptable under §1321.C must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length. [49 CFR 192.245(a)]

B. Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability. [49 CFR 192.245(b)]

C. Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under §1305. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair. [49 CFR 192.245(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 9:230 (April 1983), amended LR 10:522 (July 1984), LR 30:1242 (June 2004).

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

§1501. Scope [49 CFR 192.271]

A. This Chapter prescribes minimum requirements for joining materials in pipelines, other than by welding. [49 CFR 192.271(a)]

B. This Chapter does not apply to joining during the manufacture of pipe or pipeline components. [49 CFR 192.271(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 9:230 (April 1983), amended LR 10:523 (July 1984), LR 30:1243 (June 2004).

§1503. General [49 CFR 192.273]

A. The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading. [49 CFR 192.273(a)]

B. Each joint must be made in accordance with written procedures that have been proved by test or experience to produce strong gastight joints. [49 CFR 192.273(b)]

C. Each joint must be inspected to insure compliance with this Chapter. [49 CFR 192.273(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 9:230 (April 1983), amended LR 10:523 (July 1984), LR 30:1243 (June 2004).

§1505. Cast Iron Pipe [49 CFR 192.275]

A. Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps. [49 CFR 192.275(a)]

B. Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring. [49 CFR 192.275(b)]

C. Cast iron pipe may not be joined by threaded joints. [49 CFR 192.275(c)]

D. Cast iron may not be joined by brazing. [49 CFR 192.275(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 9:230 (April 1983), amended LR 10:523 (July 1984), LR 18:856 (August 1992), LR 20:445 (April 1994), LR 30:1243 (June 2004).

§1507. Ductile Iron Pipe [49 CFR 192.277]

A. Ductile iron pipe may not be joined by threaded joints. [49 CFR 192.277(a)]

B. Ductile iron pipe may not be joined by brazing. [49 CFR 192.277(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 9:230 (April 1983), amended LR 10:523 (July 1984), LR 18:856 (August 1992), LR 30:1243 (June 2004).

§1509. Copper Pipe [49 CFR 192.279]

A. Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5. [49 CFR 192.279]

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 18:856 (August 1992), LR 20:445 (April 1994), LR 30:1243 (June 2004).

§1511. Plastic Pipe [49 CFR 192.281]

A. General. A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint. [49 CFR 192.281(a)]

B. Solvent Cement Joints. Each solvent cement joint on plastic pipe must comply with the following. [49 CFR 192.281(b)]

1. The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint. [49 CFR 192.281(b)(1)]

2. The solvent cement must conform to ASTM D 2620-12 for PVC (incorporated by reference, see §507) [49 CFR 192.281(b)(2)]

3. The joint may not be heated or cooled to accelerate the setting of the cement. [49 CFR 192.281(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)]

1. A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under §1513. [49 CFR 192.281(c)(1)]

2. A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously to establish the same temperature. The device used must be the same device specified in the operator's joining procedure for socket fusion. [49 CFR 192.281(c)(2)]

3. An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer, or using equipment and techniques shown, by testing joints to the requirements of §1513.A.1.c, to be at least equivalent to or better than the requirements of the fitting manufacturer. [49 CFR 192.281(c)(3)]

4. Heat may not be applied with a torch or other open flame. [49 CFR 192.281(c)(4)]

D. Adhesive Joints. Each adhesive joint on plastic pipe must comply with the following. [49 CFR 192.281(d)]

1. The adhesive must conform to ASTM D 2517 (incorporated by reference, see §507). [49 CFR 192.281(d)(1)]

2. The materials and adhesive must be compatible with each other. [49 CFR 192.281(d)(2)]

E. Mechanical Joints. Each compression type mechanical joint on plastic pipe must comply with the following. [49 CFR 192.281(e)]

1. The gasket material in the coupling must be compatible with the plastic. [49 CFR 192.281(e)(1)]

2. A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling. [49 CFR 192.281(e)(2)]

3. All mechanical fittings must meet a listed specification based upon the applicable material. [49 CFR 192.281(e)(3)]

4. All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25 percent elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard. [49 CFR 192.281(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).

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

A. Heat Fusion, Solvent Cement, and Adhesive Joints. Before any written procedure established under §1503.B is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests, as applicable: [49 CFR 192.283(a)]

1. the test requirements of: [49 CFR 192.283(a)(1)]

a. in the case of thermoplastic pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification; [49 CFR 192.283(a)(1)(i)]

b. in the case of thermosetting plastic pipe, paragraph 8.5 (minimum hydrostatic burst pressure) or paragraph 8.9 (sustained static pressure test) of ASTM D2517-00 (incorporated by reference, see §507); or [49 CFR 192.283(a)(1)(ii)]

c. in the case of electrofusion fittings for polyethylene pipe (PE) and tubing, paragraph 9.1 (minimum hydraulic burst pressure test), paragraph 9.2 (sustained pressure test), paragraph 9.3 (tensile strength test), or paragraph 9.4 (joint integrity tests) of ASTM Designation F1055-98(2006) (incorporated by reference, see §507) [49 CFR 192.283(a)(1)(iii)]

2. for procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use. [49 CFR 192.283(a)(2)]

3. for procedures intended for non-lateral pipe connections, perform testing in accordance with a listed specification. If the test specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use. [49 CFR 192.283(a)(3)].

B. Mechanical Joints. Before any written procedure established under §1503.B is used for making mechanical plastic pipe joints, the procedure must be qualified in accordance with a listed specification based upon the pipe material. [49 CFR 192.283(b)]

C. A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints. [49 CFR 192.283(c)]

D. Pipe or fittings manufactured before July 1, 1980, may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe. [49 CFR 192.283(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 9:231 (April 1983), amended LR 10:523 (July 1984), LR 20:445 (April 1994), LR 24:1310 (July 1998), LR 27:1541 (September 2001), LR 30:1244 (June 2004), LR 31:683 (March 2005), LR 33:479 (March 2007), LR 38:116 (January 2012), LR 44:1039 (June 2018), LR 46:1585 (November 2020), LR. 47:1144 (August 2021).

§1515. Plastic Pipe: Qualifying Persons to Make Joints [49 CFR 192.285]

A. No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by: [49 CFR 192.285(a)]

1. appropriate training or experience in the use of the procedure; and [49 CFR 192.285(a)(1)]

2. making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in Subsection B of this Section. [49 CFR 192.285(a)(2)]

B. The specimen joint must be: [49 CFR 192.285(b)]

1. visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and [49 CFR 192.285(b)(1)]

2. in the case of a heat fusion, solvent cement, or adhesive joint: [49 CFR 192.285(b)(2)]

a. tested under any one of the test methods listed under §1513.A, and for PE heat fusion joints (except for electrofusion joints) visually inspected in accordance with ASTM F2620 (incorporated by reference, see §507) or a written procedure that has been demonstrated to provide an equivalent or superior level of safety, applicable to the type of joint and material being tested; [49 CFR 192.285(b)(2)(i)]

b. examined by ultrasonic inspection and found not to contain flaws that would cause failure; or [49 CFR 192.285(b)(2)(ii)]

c. cut into at least three longitudinal straps, each of which is: [49 CFR 192.285(b)(2)(iii)]

i. visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and [49 CFR 192.285(b)(2)(iii)(A)]

ii. deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area. [49 CFR 192.285(b)(2)(iii)(B)]

C. A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months or after any production joint is found unacceptable by testing under §2313. [49 CFR 192.285(c)]

D. Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this Section. [49 CFR 192.285(d)]

E. For transmission pipe installed after July 1, 2021, records demonstrating each person’s plastic pipe joining qualifications at the time of construction in accordance with this Section must be retained for a minimum of five years following construction. [49 CFR 192.285(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 9:231 (April 1983), amended LR 10:524 (July 1984), LR 30:1244 (June 2004), LR 33:480 (March 2007), LR 44:1039 (June 2018), LR 46:1586 (November 2020), LR 47:1144 (August 2021), repromulgated LR 47:1332 (September 2021).

§1517. Plastic Pipe: Inspection of Joints [49 CFR 192.287]

A. No person may carry out the inspection of joints in plastic pipes required by §1503.C and §1515.B unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure. [49 CFR 192.287]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:232 (April 1983), amended LR 10:524 (July 1984), LR 30:1245 (June 2004), LR 33:480 (March 2007).

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

§1701. Scope [49 CFR 192.301]

A. This Chapter prescribes minimum requirements for constructing transmission lines and mains. [49 CFR 192.301]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:232 (April 1983), amended LR 10:524 (July 1984), LR 30:1245 (June 2004).

§1703. Compliance with Specifications or Standards [49 CFR 192.303]

A. Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this Subpart. [49 CFR 192.303]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:232 (April 1983), amended LR 10:524 (July 1984), LR 20:446 (April 1994), LR 30:1245 (June 2004).

§1705. Inspection: General [49 CFR 192.305]

A. Each transmission line or main must be inspected to ensure that it is constructed in accordance with this Subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks. [49 CFR 192.305]

B. Each operator shall notify the Pipeline Safety Section of the Office of Conservation, Louisiana Department of Natural Resources of any new proposed pipeline construction or replacement for a total length of 1 mile or more on transmission lines or mains at least 48 hours prior to commencement of said construction.

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

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

§1707. Inspection of Materials [49 CFR 192.307]

A. Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability. [49 CFR 192.307]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:232 (April 1983), amended LR 10:524 (July 1984), LR 30:1245 (June 2004).

§1709. Repair of Steel Pipe [49 CFR 192.309]

A. Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either: [49 CFR 192.309(a)]

1. the minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or [49 CFR 192.309(a)(1)]

2. the nominal wall thickness required for the design pressure of the pipeline. [49 CFR 192.309(a)(2)]

B. Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe: [49 CFR 192.309(b)]

1. a dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn; [49 CFR 192.309(b)(1)]

2. a dent that affects the longitudinal weld or a circumferential weld; [49 CFR 192.309(b)(2)]

3. in pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of: [49 CFR 192.309(b)(3)]

a. more than 1/4 inch (6.4 millimeters) in pipe 12 3/4 inches (324 millimeters) or less in outer diameter; or [49 CFR 192.309(b)(3)(i)]

b. more than 2 percent of the nominal pipe diameter in pipe over 12 3/4 inches (324 millimeters) in outer diameter. [49 CFR 192.309(b)(3)(ii)]

C. For the purpose of this Section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

D. Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either: [49 CFR 192.309(c)]

1. the minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or [49 CFR 192.309(c)(1)]

2. the nominal wall thickness required for the design pressure of the pipeline. [49 CFR 192.309(c)(2)]

E. A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out. [49 CFR 192.309(d)]

F. Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder. [49 CFR 192.309(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 9:232 (April 1983), amended LR 10:524 (July 1984), LR 18:857 (August 1992), LR 27:1542 (September 2001), LR 30:1245 (June 2004).

§1711. Repair of Plastic Pipe [49 CFR 192.311]

A. Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed. [49 CFR 192.311]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:232 (April 1983), amended LR 10:524 (July 1984), LR 30:1246 (June 2004).

§1713. Bends and Elbows [49 CFR 192.313]

A. Each field bend in steel pipe, other than a wrinkle bend made in accordance with §1715, must comply with the following. [49 CFR 192.313(a)]

1. A bend must not impair the serviceability of the pipe. [49 CFR 192.313(a)(1)]

2. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. [49 CFR 192.313(a)(2)]

3. On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless: [49 CFR 192.313(a)(3)]

a. the bend is made with an internal bending mandrel; or [49 CFR 192.313(a)(3)(i)]

b. the pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70. [49 CFR 192.313(a)(3)(ii)]

B. Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. [49 CFR 192.313(b)]

C. Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters). [49 CFR 192.313(c)]

D. An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed. [49 CFR 192.313(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 9:232 (April 1983), amended LR 10:524 (July 1984), LR 27:1542 (September 2001), LR 30:1246 (June 2004), LR 46:1586 (November 2020).

§1715. Wrinkle Bends in Steel Pipe [49 CFR 192.315]

A. A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS. [49 CFR 192.315(a)]

B. Each wrinkle bend on steel pipe must comply with the following. [49 CFR 192.315(b)]

1. The bend must not have any sharp kinks. [49 CFR 192.315(b)(1)]

2. When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter. [49 CFR 192.315(b)(2)]

3. On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1 1/2º for each wrinkle. [49 CFR 192.315(b)(3)]

4. On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend. [49 CFR 192.315(b)(4)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:232 (April 1983), amended LR 10:525 (July 1984), LR 27:1542 (September 2001), LR 30:1246 (June 2004).

§1717. Protection from Hazards [49 CFR 192.317]

A. The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations. [49 CFR 192.317(a)]

B. Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades. [49 CFR 192.317(b)]

C. Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels. [49 CFR 192.317(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 9:232 (April 1983), amended LR 10:525 (July 1984), LR 20:446 (April 1994), LR 24:1310 (July 1998), LR 30:1246 (June 2004).

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

A. When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage. [49 CFR 192.319(a)]

B. When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that: [49 CFR 192.319(b)]

1. provides firm support under the pipe; and [49 CFR 192.319(b)(1)]

2. prevents damage to the pipe and pipe coating from equipment or from the backfill material. [49 CFR 192.319(b)(2)]

C. All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation. [49 CFR 192.319(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 9:233 (April 1983), amended LR 10:525 (July 1984), LR 20:446 (April 1994), LR 24:1310 (July 1998), LR 27:1542 (September 2001), LR 30:1246 (June 2004).

§1721. Installation of Plastic Pipe [49 CFR 192.321]

A. Plastic pipe must be installed below ground level except as provided by Subsections G, H, and I of this Section. [49 CFR 192.321(a)]

B. Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion. [49 CFR 192.321(b)]

C. Plastic pipe must be installed so as to minimize shear or tensile stresses. [49 CFR 192.321(c)]

D. Plastic pipe must have a minimum wall thickness in accordance with §921. [49 CFR 192.321(d)]

E. Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means. [49 CFR 192.321(e)]

F. Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. Plastic pipe that is being encased must be protected from damage at all entrance and all exit points of the casing. The leading end of the plastic must be closed before insertion. [49 CFR 192.321(f)]

G. Uncased plastic pipe may be temporarily installed above ground level under the following conditions. [49 CFR 192.321(g)]

1. The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or two years, whichever is less. [49 CFR 192.321(g)(1)]

2. The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage. [49 CFR 192.321(g)(2)]

3. The pipe adequately resists exposure to ultraviolet light and high and low temperatures. [49 CFR 192.321(g)(3)]

H. Plastic pipe may be installed on bridges provided that it is: [49 CFR 192.321(h)]

1. installed with protection from mechanical damage, such as installation in a metallic casing; [49 CFR 192.321(h)(1)]

2. protected from ultraviolet radiation; and [49 CFR 192.321(h)(2)]

3. not allowed to exceed the pipe temperature limits specified in §923. [49 CFR 192.321(h)(3)]

I. Plastic mains may terminate above ground level provided they comply with the following. [49 CFR 192.321(i)]

1. The above-ground level part of the plastic main is protected against deterioration and external damage. [49 CFR 192.367(i)(1)]

2. The plastic main is not used to support external loads. [49 CFR 192.367(i)(2)]

3. Installations of risers at regulator stations must meet the design requirements of §1164. [49 CFR 192.367(i)(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 9:233 (April 1983), amended LR 10:525 (July 1984), LR 24:1310 (July 1998), LR 27:1542 (September 2001), LR 30:1247 (June 2004), LR 31:684 (March 2005), LR 46:1586 (November 2020).

§1723. Casing [49 CFR 192.323]

A. Each casing used on a transmission line or main under a railroad or highway must comply with the following. [49 CFR 192.323]

1. The casing must be designed to withstand the superimposed loads. [49 CFR 192.323(a)]

2. If there is a possibility of water entering the casing, the ends must be sealed. [49 CFR 192.323(b)]

3. If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS. [49 CFR 192.323(c)]

4. If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing. [49 CFR 192.323(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 9:233 (April 1983), amended LR 10:525 (July 1984), LR 30:1247 (June 2004).

§1725. Underground Clearance [49 CFR 192.325]

A. Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure. [49 CFR 192.325(a)]

B. Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures. [49 CFR 192.325(b)]

C. In addition to meeting the requirements of Subsections A or B of this Section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe. [49 CFR 192.325(c)]

D. Each pipe-type or bottle type holder must be installed with a minimum clearance from any other holder as prescribed in §1135.B. [49 CFR 192.325(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. 47:1144 (August 2021).

§1727. Cover [49 CFR 192.327]

A. Except as provided in Subsection C, E, F and G of this Section, each buried transmission line must be installed with a minimum cover as follows. [49 CFR 192.327(a)]

Location	Normal Soil	Consolidated Rock
	Inches (Millimeters)	Inches (Millimeters)
Class 1 Locations	30 (762)	18 (457)
Class 2, 3 and 4 Locations	36 (914)	24 (610)
Drainage Ditches of Public Roads and Railroad Crossings	36 (914)	24 (610)

B. Except as provided in Subsections C and D of this Section, each buried main must be installed with at least 24 inches (610 millimeters) of cover. [49 CFR 192.327(b)]

C. Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads. [49 CFR 192.327(c)]

D. A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the state or municipality: [49 CFR 192.327(d)]

1. establishes a minimum cover of less than 24 inches (610 millimeters); [49 CFR 192.327(d)(1)]

2. requires that mains be installed in a common trench with other utility lines; and [49 CFR 192.327(d)(2)]

3. provides adequately for prevention of damage to the pipe by external forces. [49 CFR 192.327(d)(3)]

E. Except as provided in Subsection C of this Section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices). [49 CFR 192.327(e)]

F. All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows. [49 CFR 192.327(f)]

1. Except as provided in Subsection C of this Section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom. [49 CFR 192.327(f)(1)]

2. Pipe under water at least 12 feet (3.66 meters) deep must be installed so that the top of the pipe is below the natural bottom, unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. [49 CFR 192.327(f)(2)]

G. All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in §503, must be installed in accordance with §2712.C.3. [49 CFR 192.327(g)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:233 (April 1983), amended LR 10:525 (July 1984), LR 20:446 (April 1994), LR 24:1310 (July 1998), LR 27:1542 (September 2001), LR 30:1247 (June 2004), LR 31:684 (March 2005), LR 35:2805 (December 2009).

§1728. Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. [49 CFR 192.328]

A. For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure calculated under §2720, a segment must meet the following additional construction requirements. Records must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements: [49 CFR 192.328]

1. to address these construction issues (a.-e.): The pipeline segment must meet this additional construction requirement: [49 CFR 192.328]

a. Quality assurance. [49 CFR 192.328(a)]

i. The construction of the pipeline segment must be done under a quality assurance plan addressing pipe inspection, hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing. [49 CFR 192.328(a)(1)]

ii. The quality assurance plan for applying and testing field applied coating to girth welds must be: [49 CFR 192.328(a)(2)]

(a). Equivalent to that required under §912.A.1.f.iii for pipe; and [49 CFR 192.328(a)(2)(i)]

(b). Performed by an individual with the knowledge, skills, and ability to assure effective coating application. [49 CFR 192.328(a)(2)(ii)]

b. Girth welds. [49 CFR 192.328(b)]

i. All girth welds on a new pipeline segment must be non- destructively examined in accordance with §1323.B and C. [49 CFR 192.328(b)(1)]

c. Depth of cover. [49 CFR 192.328(c)]

i. Notwithstanding any lesser depth of cover otherwise allowed in §1727, there must be at least 36 inches (914 millimeters) of cover or equivalent means to protect the pipeline from outside force damage. [49 CFR 192.328(c)(1)]

ii. In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.[49 CFR 192.328(c)(2)]

d. Initial strength testing. [49 CFR 192.328(d)]

i. The pipeline segment must not have experienced failures indicative of systemic material defects during strength testing, including initial hydrostatic testing. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipe is in service at least 60 days prior to operating at the alternative MAOP. An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state. [49 CFR 192.328(d)(1)]

e. Interference currents. [49 CFR 192.328(e)]

i. For a new pipeline segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.[49 CFR 192.328(e)(1)]

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 35:2805 (December 2009).

§1729. Installation of Plastic Pipelines by Trenchless Excavation [49 CFR 192.329] [Formerly §1725]

A. Plastic pipelines installed by trenchless excavation must comply with the following. [49 CFR 192.329]

1. Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation. [49 CFR 192.329(a)]

2. For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by § 503, to ensure the pipeline will not be damaged by any excessive forces during the pulling process. [49 CFR 192.329(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 46:1586 (November 2020), amended LR 47:1144 (August 2021).

Chapter 19. Customer Meters, Service Regulators, and Service Lines [49 CFR Part 192 Subpart H]

§1901. Scope [49 CFR 192.351]

A. This Chapter prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains. [49 CFR 192.351]

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 10:526 (July 1984), LR 30:1248 (June 2004).

§1903. Customer Meters and Regulators: Location [49 CFR 192.353]

A. Each meter and service regulator whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried. [49 CFR 192.353(a)]

B. Each service regulator installed within a building must be located as near as practical to the point of service line entrance. [49 CFR 192.353(b)]

C. Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter. [49 CFR 192.353(c)]

D. Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building. [49 CFR 192.353(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 9:233 (April 1983), amended LR 10:526 (July 1984), LR 27:1543 (September 2001), LR 30:1248 (June 2004).

§1905. Customer Meters and Regulators: Protection from Damage [49 CFR 192.355]

A. Protection from Vacuum or Back Pressure. If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system. [49 CFR 192.355(a)]

B. Service Regulator Vents and Relief Vents. Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must: [49 CFR 192.355(b)]

1. be rain and insect resistant; [49 CFR 192.355(b)(1)]

2. be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and [49 CFR 192.355(b)(2)]

3. be protected from damage caused by submergence in areas where flooding may occur. [49 CFR 192.355(b)(3)]

C. Pits and Vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic. [49 CFR 192.355(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 9:233 (April 1983), amended LR 10:526 (July 1984), LR 30:1248 (June 2004).

§1907. Customer Meters and Regulators: Installation [49 CFR 192.357]

A. Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter. [49 CFR 192.357(a)]

B. When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this Subpart. [49 CFR 192.357(b)]

C. Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators. [49 CFR 192.357(c)]

D. Each regulator that might release gas in its operation must be vented to the outside atmosphere. [49 CFR 192.357(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 9:234 (April 1983), amended LR 10:526 (July 1984), LR 30:1248 (June 2004).

§1909. Customer Meter Installations: Operating Pressure, [49 CFR 192.359]

A. A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure. [49 CFR 192.359(a)]

B. Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 psi (69 kPa) gage. [49 CFR 192.359(b)]

C. A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing. [49 CFR 192.359(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 9:234 (April 1983), amended LR 10:526 (July 1984), LR 27:1543 (September 2001), LR 30:1248 (June 2004).

§1911. Service Lines: Installation [49 CFR 192.361]

A. Depth. Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load. [49 CFR 192.361(a)]

B. Support and Backfill. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating. [49 CFR 192.361(b)]

C. Grading for Drainage. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line. [49 CFR 192.361(c)]

D. Protection against Piping Strain and External Loading. Each service line must be installed so as to minimize anticipated piping strain and external loading. [49 CFR 192.361(d)]

E. Installation of Service Lines into Buildings. Each underground service line installed below grade through the outer foundation wall of a building must: [49 CFR 192.361(e)]

1. in the case of a metal service line, be protected against corrosion; [49 CFR 192.361(e)(1)]

2. in the case of a plastic service line, be protected from shearing action and backfill settlement; and [49 CFR 192.361(e)(2)]

3. be sealed at the foundation wall to prevent leakage into the building. [49 CFR 192.361(e)(3)]

F. Installation of Service Lines under Buildings. Where an underground service line is installed under a building: [49 CFR 192.361(f)]

1. it must be encased in a gas-tight conduit; [49 CFR 192.361(f)(1)]

2. the conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and [49 CFR 192.361(f)(2)]

3. the space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting. [49 CFR 192.361(f)(3)]

G. Locating Underground Service Lines. Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with §1721.E. [49 CFR 192.361(g)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:234 (April 1983), amended LR 10:526 (July 1984), LR 27:1543 (September 2001), LR 30:1249 (June 2004).

§1913. Service Lines: Valve Requirements [49 CFR 192.363]

A. Each service line must have a service-line valve that meets the applicable requirements of Chapter 7 and Chapter 11 of this Subpart. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve. [49 CFR 192.363(a)]

B. A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat. [49 CFR 192.363(b)]

C. Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools. [49 CFR 192.363(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 9:234 (April 1983), amended LR 10:526 (July 1984), LR 30:1249 (June 2004).

§1915. Service Lines: Location of Valves, [49 CFR 192.365]

A. Relation to Regulator or Meter. Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter. [49 CFR 192.365(a)]

B. Outside Valves. Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building. [49 CFR 192.365(b)]

C. Underground Valves. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines. [49 CFR 192.365(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 9:234 (April 1983), amended LR 10:526 (July 1984), LR 30:1249 (June 2004).

§1917. Service Lines: General Requirements for Connections to Main Piping [49 CFR 192.367]

A. Location. Each service-line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line. [49 CFR 192.367(a)]

B. Compression-Type Connection to Main. Each compression-type service line to main connection must: [49 CFR 192.367(b)]

1. be designed and installed to effectively sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; [49 CFR 192.367(b)(1)]

2. if gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system; and [49 CFR 192.367(b)(2)]

3. if used on pipelines comprised of plastic, be a Category 1 connection as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25 percent elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard. [49 CFR 192.367(b)(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 9:234 (April 1983), amended LR 10:526 (July 1984), LR 30:1249 (June 2004), LR 46:1587 (November 2020).

§1919. Service Lines: Connections to Cast Iron or Ductile Iron Mains [49 CFR 192.369]

A. Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of §1503. [49 CFR 192.369(a)]

B. If a threaded tap is being inserted, the requirements of §1111.B and C must also be met. [49 CFR 192.369(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 9:234 (April 1983), amended LR 10:527 (July 1984), LR 30:1250 (June 2004).

§1921. Service Lines: Steel [49 CFR 192.371]

A. Each steel service line to be operated at less than 100 psi (689 kPa) gage must be constructed of pipe designed for a minimum of 100 psi (689 kPa) gage. [49 CFR 192.371]

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 9:234 (April 1983), amended LR 10:527 (July 1984), LR 27:1543 (September 2001), LR 30:1250 (June 2004).

§1923. Service Lines: Cast Iron and Ductile Iron [49 CFR 192.373]

A. Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines. [49 CFR 192.373(a)]

B. If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe. [49 CFR 192.373(b)]

C. A cast iron or ductile iron service line may not be installed in unstable soil or under a building. [49 CFR 192.373(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 9:234 (April 1983), amended LR 10:527 (July 1984), LR 27:1543 (September 2001), LR 30:1250 (June 2004).

§1925. Service Lines: Plastic [49 CFR 192.375]

A. Each plastic service line outside a building must be installed below ground level, except that: [49 CFR 192.375(a)]

1. it may be installed in accordance with §1721.G; and [49 CFR 192.375(a)(1)]

2. it may terminate above ground level and outside the building, if: [49 CFR 192.375(a)(2)]

a. the above ground level part of the plastic service line is protected against deterioration and external damage; [49 CFR 192.375(a)(2)(i)]

b. the plastic service line is not used to support external loads; and [49 CFR 192.375(a)(2)(ii)]

c. the riser portion of the service line meets the design requirements of §1164. [49 CFR 192.375(a)(2)(iii)]

B. Each plastic service line inside a building must be protected against external damage. [49 CFR 192.375(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 9:234 (April 1983), amended LR 10:527 (July 1984), amended LR 24:1310 (July 1998), LR 30:1250 (June 2004), LR 46:1587 (November 2020).

§1926. Installation of Plastic Service Lines by Trenchless Excavation [49 CFR 192.376]

A. Plastic service lines installed by trenchless excavation must comply with the following. [49 CFR 192.376]

1. Each operator shall take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and structures at the time of installation. [49 CFR 192.376(a)]

2. For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by §503, to ensure the pipeline will not be damaged by any excessive forces during the pulling process. [49 CFR 192.376(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 46:1587 (November 2020).

§1927. Service Lines: Copper [49 CFR 192.377]

A. Each copper service line installed within a building must be protected against external damage. [49 CFR 192.377]

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 30:1250 (June 2004).

§1929. New Service Lines Not in Use [49 CFR 192.379]

A. Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas: [49 CFR 192.379]

1. the valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator; [49 CFR 192.379(a)]

2. a mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly; [49 CFR 192.379(b)]

3. the customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed. [49 CFR 192.379(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 9:235 (April 1983), amended LR 10:527 (July 1984), LR 30:1250 (June 2004).

§1931. Service Lines: Excess Flow Valve Performance Standards [49 CFR 192.381]

A. Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 psi (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will: [49 CFR 192.381(a)]

1. function properly up to the maximum operating pressure at which the valve is rated; [49 CFR 192.381(a)(1)]

2. function properly at all temperatures reasonably expected in the operating environment of the service line; [49 CFR 192.381(a)(2)]

3. at 10 psi (69 kPa) gage: [49 CFR 192.381(a)(3)]

a. close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and [49 CFR 192.381(a)(3)(i)]

b. upon closure, reduce gas flow: [49 CFR 192.381(a)(3)(ii)

i. for an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or [49 CFR 192.381(a)(3)(ii)(A)]

ii. for an excess flow valve designed to prevent equalization of pressure across the valve, to no more than

0.4 cubic feet per hour (0.01 cubic meters per hour); and [49 CFR 192.381(a)(3)(ii)(B)]

4. not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate. [49 CFR 192.381(a)(4)]

B. An excess flow valve must meet the applicable requirements of Chapters 7 and 11 of this Subpart. [49 CFR 192.381(b)]

C. An operator must mark or otherwise identify the presence of an excess flow valve on the service line. [49 CFR 192.381(c)]

D. An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply. [49 CFR 192.381(d)]

E. An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line. [49 CFR 192.381(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 24:1311 (July 1998), amended LR 27:1543 (September 2001), LR 30:1250 (June 2004), LR 44:1039 (June 2018).

§1933. Excess Flow Valve Customer Installation [49 CFR 192.383]

A. Definitions. As used in this Section: [49 CFR 192.383(a)]

Branched Service Line—a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

Replaced Service Line—a natural gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced;

Service Line Serving Single-family Residence—a natural gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

B. Installation Required. An EFV installation must comply with the performance standards in §1931. After April 14, 2017, each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated: [49 CFR 192.383(b)]

1. a single service line to one SFR; [49 CFR 192.383(b)(1)]

2. a branched service line to a SFR installed concurrently with the primary SFR service line (i.e., a single EFV may be installed to protect both service lines); [49 CFR 192.383(b)(2)

3. a branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV; [49 CFR 192.383(b)(3)]

4. multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation based on installed meter capacity, and [49 CFR 192.383(b)(4)]

5. a single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity. [49 CFR 192.383(b)(5)

C. Exceptions to excess flow valve installation requirement. An operator need not install an excess flow valve if one or more of the following conditions are present: [49 CFR 192.383(c)]

1. the service line does not operate at a pressure of 10 psig or greater throughout the year; [49 CFR 192.383(c)(1)]

2. the operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer [49 CFR 192.383(c)(2)]

3. an EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or [49 CFR 192.383(c)(3)]

4. an EFV meeting performance standards in §1931 is not commercially available to the operator. [49 CFR 192.383(c)(4)]

D. Customer’s right to request an EFV. Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in Subsection C of this Section may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator’s rate-setter determines how and to whom the costs of the requested EFVs are distributed. [49 CFR 192.383(d)]

E. Operator notification of customers concerning EFV installation. Operators must notify customers of their right to request an EFV in the following manner:

1. Except as specified in Subsection C and Paragraph E.5 of this Section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e-billing notices. [49 CFR 192.383(e)(1)]

2. The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks. [49 CFR 192.383(e)(2)

3. The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known. [49 CFR 192.383(e)(3)]

4. The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of Subsection C are not present, the operator must install an EFV at a mutually agreeable date. [49 CFR 192.383(e)(4)]

5. Operators of master-meter systems and liquefied petroleum gas (LPG) operators with fewer than 100 customers may continuously post a general notification in a prominent location frequented by customers. [49 CFR 192.383(e)(5)]

F. Operator evidence of customer notification. An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106. [49 CFR 192.383(f)]

G. Reporting. Except for operators of master-meter systems and LPG operators with fewer than 100 customers, each operator must report the EFV measures detailed in the annual report required by §311 of this Part. [49 CFR 192.383(g)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 27:1544 (September 2001), amended LR 30:1251 (June 2004), LR 38:116 (January 2012), LR 44:1040 (June 2018), LR 46:1587 (November 2020).

§1935. Manual Service Line Shut-Off Valve Installation [49 CFR 192.385]

A. Definitions, as used in this Section.

Manual Service Line Shut-Off Valve—a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed. [49 CFR 192.385(a)]

B. Installation Requirement. The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH. [49 CFR 192.385(b)]

C. Accessibility and Maintenance. Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification. [49 CFR 192.385(c)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 44:1040 (June 2018).

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

§2101. Scope [49 CFR 192.451]

A. This Chapter prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmosphere corrosion. [49 CFR 192.451(a)]

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).

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

A. Converted pipelines. Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this Subpart in accordance with §514 must meet the requirements of this Chapter specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within one year after the pipeline is readied for service. However, the requirements of this Chapter specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered [49 CFR 192.452(a)].

B. 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)].

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).

§2105. General [49 CFR 192.453]

A. The corrosion control procedures required by §2705.B.2, including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods. [49 CFR 192.453]

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 21:821 (August 1995), LR 30:1252 (June 2004).

§2107. External Corrosion Control: Buried or Submerged Pipelines Installed after July 31, 1971 [49 CFR 192.455]

A. Except as provided in Subsections B, C, F, and G of this Section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following. [49 CFR 192.455(a)]

1. It must have an external protective coating meeting the requirements of §2113. [49 CFR 192.455(a)(1)]

2. It must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this Chapter, installed and placed in operation within one year after completion of construction. [49 CFR 192.455(a)(2)]

B. An operator need not comply with Subsection A of this Section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within six months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the test made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with Paragraph A.2 of this Section. [49 CFR 192.455(b)]

C. An operator need not comply with Subsection A of this Section, if the operator can demonstrate by tests, investigation, or experience that: [49 CFR 192.455(c)]

1. for a copper pipeline, a corrosive environment does not exist; or [49 CFR 192.455(c)(1)]

2. for a temporary pipeline with an operating period of service not to exceed five years beyond installation, corrosion during the five-year period of service of the pipeline will not be detrimental to public safety. [49 CFR 192.455(c)(2)]

D. Notwithstanding the provisions of Subsection B or C of this Section, if a pipeline is externally coated, it must be cathodically protected in accordance with Paragraph A.2 of this Section. [49 CFR 192.455(d)]

E. Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8, unless tests or experience indicate its suitability in the particular environment involved. [49 CFR 192.455(e)]

F. This Section does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if: [49 CFR 192.455(f)]

1. for the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and [49 CFR 192.455(f)(1)]

2. the fitting is designed to prevent leakage caused by localized corrosion pitting. [49 CFR 192.455(f)(2)]

G. Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of Subsection F must be cathodically protected, and must be maintained in accordance with the operator’s integrity management plan. [49 CFR 192.455(g)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:235 (April 1983), amended LR 10:527 (July 1984), LR 24:1311 (July 1998), LR 27:1544 (September 2001), LR 30:1252 (June 2004), LR 46:1587 (November 2020).

§2109. External Corrosion Control: Buried or Submerged Pipelines Installed before August 1, 1971 [49 CFR 192.457]

A. Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this Chapter. For the purposes of this Chapter, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements. [49 CFR 192.457(a)]

B. Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this Chapter in areas in which active corrosion is found: [49 CFR 192.457(b)]

1. bare or ineffectively coated transmission lines; [49 CFR 192.457(b)(1)]

2. bare or coated pipes at compressor, regulator, and measuring stations; [49 CFR 192.457(b)(2)]

3. bare or coated distribution lines. [49 CFR 192.457(b)(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 9:235 (April 1983), amended LR 10:527 (July 1984), LR 30:1252 (June 2004).

§2111. External Corrosion Control: Examination of Buried Pipeline When Exposed [49 CFR 192.459]

A. Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under §§2135 through 2141 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion. [49 CFR 192.459]

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 10:528 (July 1984), LR 27:1544 (September 2001), LR 30:1253 (June 2004).

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

A. Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must: [49 CFR 192.461(a)]

1. be applied on a properly prepared surface; [49 CFR 192.461(a)(1)]

2. have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture; [49 CFR 192.461(a)(2)]

3. be sufficiently ductile to resist cracking; [49 CFR 192.461(a)(3)]

4. have sufficient strength to resist damage due to handling and soil stress; and [49 CFR 192.461(a)(4)]

5. have properties compatible with any supplemental cathodic protection. [49 CFR 192.461(a)(5)]

B. Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance. [49 CFR 192.461(b)]

C. Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired. [49 CFR 192.461(c)]

D. Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks. [49 CFR 192.461(d)]

E. If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation. [49 CFR 192.461(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 9:236 (April 1983), amended LR 10:528 (July 1984), LR 30:1253 (June 2004).

§2115. External Corrosion Control: Cathodic Protection [49 CFR 192.463]

A. Each cathodic protection system required by this Chapter must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in §5107, Appendix D of this Subpart. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria. [49 CFR 192.463(a)]

B. If amphoteric metals are included in a buried or submerged pipeline containing a metal or different anodic potential: [49 CFR 192.463(b)]

1. the amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or [49 CFR 192.463(b)(1)]

2. the entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meet the requirements of §5107, Appendix D of this Subpart for amphoteric metals. [49 CFR 192.463(b)(2)]

C. The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe. [49 CFR 192.463(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 9:236 (April 1983), amended LR 10:528 (July 1984), LR 30:1253 (June 2004).

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

A. Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §2115. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period. [49 CFR 192.465(a)]

B. Cathodic protection rectifiers and impressed current power sources must be periodically inspected as follows: [49 CFR 192.465(b)]

1. Each cathodic protection rectifier or impressed current power source must be inspected 6 times each

calendar year, but with intervals not exceeding 2 1/2 months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier. [49 CFR 192.465(b)(1)]

2. After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months. [49 CFR 192.465(b)(2)]

C. Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding two and one-half months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months. [49 CFR 192.465(c)]

D. Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring. Remedial action must be completed within a time period determined by the operator based on an evaluation of the degree of hazard created by the nature of the deficiency but in no case longer than 90 days from the date the deficiency was discovered, or within a time period as may be approved by the commissioner. [49 CFR 192.465(d)]

E. After the initial evaluation required by of §2107.B and C and §2109.B, each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this Chapter in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. [49 CFR 192.465(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 9:236 (April 1983), amended LR 10:528 (July 1984), LR 27:1545 (September 2001), LR 30:1253 (June 2004), LR 38:116 (January 2012), LR 47:1144 (August 2021).

§2119. External Corrosion Control: Electrical Isolation [49 CFR 192.467]

A. Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit. [49 CFR 192.467(a)]

B. One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control. [49 CFR 192.467(b)]

C. Except for unprotected copper inserted in a ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing. [49 CFR 192.467(c)]

D. Inspection and electrical tests must be made to assure that electrical isolation is adequate. [49 CFR 192.467(d)]

E. An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing. [49 CFR 192.467(e)]

F. Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices. [49 CFR 192.467(f)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:236 (April 1983), amended LR 10:528 (July 1984), LR 30:1254 (June 2004).

§2121. External Corrosion Control: Test Stations [49 CFR 192.469]

A. Each pipeline under cathodic protection required by this Chapter must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection. [49 CFR 192.469]

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

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

§2123. External Corrosion Control: Test Leads [49 CFR 192.471]

A. Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive. [49 CFR 192.471(a)]

B. Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe. [49 CFR 192.471(b)]

C. Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire. [49 CFR 192.471(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 9:236 (April 1983), amended LR 10:529 (July 1984), LR 30:1254 (June 2004).

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

A. Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents. [49 CFR 192.473(a)]

B. Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures. [49 CFR 192.473(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 9:236 (April 1983), amended LR 10:529 (July 1984), LR 30:1254 (June 2004).

§2127. Internal Corrosion Control: General [49 CFR 192.475]

A. Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion. [49 CFR 192.475(a)]

B. Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found: [49 CFR 192.475(b)]

1. the adjacent pipe must be investigated to determine the extent of internal corrosion; [49 CFR 192.475(b)(1)]

2. replacement must be made to the extent required by the applicable Subsections of §§2137, 2139, or 2141; and [49 CFR 192.475(b)(2)]

3. steps must be taken to minimize the internal corrosion. [49 CFR 192.475(b)(3)]

C. Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m^3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders. [49 CFR 192.475(c)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:237 (April 1983), amended LR 10:529 (July 1984), LR 20:446 (April 1994), LR 24:1311 (July 1998), LR 27:1545 (September 2001), LR 30:1254 (June 2004).

§2128. Internal Corrosion Control: Design and Construction of Transmission Line [49 CFR 192.476]

A. Design and construction. Except as provided in subsection B of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must: [49 CFR 192.476(a)]

1. be configured to reduce the risk that liquids will collect in the line; [49 CFR 192.476(a)(1)]

2. have effective liquid removal features whenever the configuration would allow liquids to collect; and [49 CFR 192.476(a)(2)]

3. allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion. [49 CFR 192.476(a)(3)]

B. Exceptions to applicability. The design and construction requirements of Subsection A of this Section do not apply to the following: [49 CFR 192.476(b)]

1. offshore pipeline; and [49 CFR 192.476(b)(1)]

2. pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007. [49 CFR 192.476(b)(2)]

C. Change to existing transmission line. When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate. [49 CFR 192.476(c)]

D. Records. An operator must maintain records demonstrating compliance with this Section. Provided the records show why incorporating design features addressing paragraph A.1, A.2, or A.3 of this Section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records. [49 CFR 192.476(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 35:2806 (December 2009).

§2129. Internal Corrosion Control: Monitoring [49 CFR 192.477]

A. If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding seven and one-half months. [49 CFR 192.477]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:237 (April 1983), amended LR 10:529 (July 1984), LR 30:1255 (June 2004).

§2131. Atmospheric Corrosion Control: General [49 CFR 192.479]

A. Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under Subsection C of this Section. [49 CFR 192.479(a)]

B. Coating material must be suitable for the prevention of atmospheric corrosion. [49 CFR 192.479(b)]

C. Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will: [49 CFR 192.479(c)]

1. only be a light surface oxide; or [49 CFR 192.479(c)(1)]

2. not affect the safe operation of the pipeline before the next scheduled inspection. [49 CFR 192.479(c)(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 9:237 (April 1983), amended LR 10:529 (July 1984), LR 30:1255 (June 2004).

§2133. Atmospheric Corrosion Control: Monitoring [49 CFR 192.481]

A. Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows. [49 CFR 192.481(a)]

If the pipeline is located:	Then the frequency of inspection is:
Onshore other than a service line	At least once every 3 calendar years, but with intervals not exceeding 39 months.
Onshore service line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in Subsection D of this Section.
Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

B. During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water. [49 CFR 192.481(b)]

C. If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by §2131. [49 CFR 192.481(c)]

D. If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months. [49 CFR 192.481(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 9:237 (April 1983), amended LR 10:529 (July 1984), LR 30:1255 (June 2004), LR 47:1145 (August 2021).

§2135. Remedial Measures: General [49 CFR 192.483]

A. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of §2113. [49 CFR 192.483(a)]

B. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this Chapter. [49 CFR 192.483(b)]

C. Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this Chapter. [49 CFR 192.483(c)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:237 (April 1983), amended LR 10:529 (July 1984), LR 30:1255 (June 2004).

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

A. General Corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this Subsection. [49 CFR 192.485(a)]

B. Localized Corrosion Pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits. [49 CFR 192.485(b)]

C. Under Subsections A and B of this Section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G (incorporated by reference, see §507) or the procedure in PRCI PR 3-805 (R-STRENG) (incorporated by reference, see §507). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures. [49 CFR 192.485(c)]

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

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

§2139. Remedial Measures: Distribution Lines Other Than Cast Iron or Ductile Iron Lines [49 CFR 192.487]

A. General Corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this Subsection. [49 CFR 192.487(a)]

B. Localized Corrosion Pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired. [49 CFR 192.487(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 9:237 (April 1983), amended LR 10:529 (July 1984), LR 27:1545 (September 2001), LR 30:1256 (June 2004).

§2141. Remedial Measures: Cast Iron and Ductile Iron Pipelines [49 CFR 192.489]

A. General Graphitization. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result, must be replaced. [49 CFR 192.489(a)]

B. Localized Graphitization. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result, must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage. [49 CFR 192.489(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 9:237 (April 1983), amended LR 10:529 (July 1984), LR 30:1256 (June 2004).

§2142. Direct Assessment [49 CFR 192.490]

A. Each operator that uses direct assessment as defined in §3303 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process [49 CFR 192.490].

Threat	Standard[1]
External corrosion	§3325[2]
Internal corrosion in pipelines that transport dry gas.	§3327
Stress corrosion cracking	§3329

[1]For lines not subject to Chapter 33 of this Subpart, the terms "covered segment" and "covered pipeline segment" in §§3325, 3327, and 3329 refer to the pipeline segment on which direct assessment is performed.

[2]In §3325B, the provision regarding detection of coating damage applies only to pipelines subject to Chapter 33 of this Subpart.

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 33:480 (March 2007).

§2143. Corrosion Control Records [49 CFR 192.491]

A. Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode. [49 CFR 192.491(a)]

B. Each record or map required by Subsection A of this Section must be retained for as long as the pipeline remains in service. [49 CFR 192.491(b)]

C. Each operator shall maintain a record of each test, survey, or inspection required by this Section in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least five years with the following exceptions: [49 CFR 192.491(c)]

1. Operators must retain records related to §§ 2117.A and E and 2127.B for as long as the pipeline remains in service. [49 CFR 192.491(c)(1)]

2. Operators must retain records of the two most recent atmospheric corrosion inspections for each distribution service line that is being inspected under the interval in §2133.A. [49 CFR 192.491(c)(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 9:237 (April 1983), amended LR 10:530 (July 1984), LR 24:1311 (July 1998), LR 30:1256 (June 2004), LR 47:1145 (August 2021).

§2145. In-Line Inspection of Pipelines [49 CFR 192.493]

A. When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102, (incorporated by reference, see §507). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable. [49 CFR 192.493]

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 46:1587 (November 2020).

Chapter 23. Test Requirements [49 CFR Part 192 Subpart J]

§2301. Scope [49 CFR 192.501]

A. This Chapter prescribes minimum leak-test and strength-test requirements for pipelines. [49 CFR 192.501]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:237 (April 1983), amended LR 10:530 (July 1984), LR 30:1256 (June 2004).

§2303. General Requirements [49 CFR 192.503]

A. No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until: [49 CFR 192.503(a)]

1. it has been tested in accordance with this Chapter and §2719 to substantiate the maximum allowable operating pressure; and [49 CFR 192.503(a)(1)]

2. each potentially hazardous leak has been located and eliminated. [49 CFR 192.503(a)(2)]

B. The test medium must be liquid, air, natural gas, or inert gas that is: [49 CFR 192.503(b)]

1. compatible with the material of which the pipeline is constructed; [49 CFR 192.503(b)(1)]

2. relatively free of sedimentary materials; and [49 CFR 192.503(b)(2)]

3. except for natural gas, nonflammable. [49 CFR 192.503(b)(3)]

C. Except as provided in §2305.A, if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply. [49 CFR 192.503(c)]

Class Location	Maximum Hoop Stress Allowed as Percentage of SMYS	
	Natural Gas	Air or Inert Gas
1	80	80
2	30	75
3	30	50
4	30	40

D. Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this Chapter, but each non-welded joint must be leak tested at not less than its operating pressure. [49 CFR 192.503(d)]

E. If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of component certifies that: [49 CFR 192.503(e)]

1. the component was tested to at least the pressure required for the pipeline to which it is being added; [49 CFR 192.503(e)(1)]

2. the component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or [49 CFR 192.503(e)(2)]

3. the component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in §1103. [49 CFR 192.503(e)(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 9:237 (April 1983), amended LR 10:530 (July 1984), LR 30:1256 (June 2004), LR 44:1041 (June 2018).

§2305. Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of 30 Percent or More of SMYS [49 CFR 192.505]

A. Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this Section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium. [49 CFR 192.505(a)]

B. In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station, must be tested to at least Class 3 location test requirements. [49 CFR 192.505(b)]

C. Except as provided in Subsection D of this Section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least eight hours. [49 CFR 192.505(c)]

D. For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation strength test must be conducted by maintaining the pressure at or above the test pressure for at least four hours. [49 CFR 192.505(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 9:238 (April 1983), amended LR 10:530 (July 1984), LR 27:1545 (September 2001), LR 30:1256 (June 2004), LR 31:684 (March 2005), LR 44:1041 (June 2018).

§2306. Transmission Lines: Spike Hydrostatic Pressure Test [49 CFR 192.506]

A. Spike Test Requirements. Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this Section. [49 CFR 192.506(a)]

1. The test must use water as the test medium. [49 CFR 192.506(a)(1)]

2. The baseline test pressure must be as specified in the applicable Paragraphs of §2719.A.2 or §2720.A.2, whichever applies. [49 CFR 192.506(a)(2)]

3. The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least eight hours as specified in §2305. [49 CFR 192.506(a)(3)]

4. After the test pressure stabilizes at the baseline pressure and within the first two hours of the eight-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100 percent SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes. [49 CFR 192.506(a)(4)]

B. Other Technology or Other Technical Evaluation Process. Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with §518 and must include the following information: [49 CFR 192.506(b)]

1. descriptions of the technology or technologies to be used for all tests, examinations, and assessments; [49 CFR 192.506(b)(1)]

2. procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered; [49 CFR 192.506(b)(2)]

3. data requirements, including original design, maintenance and operating history, anomaly or flaw characterization; [49 CFR 192.506(b)(3)]

4. assessment techniques and acceptance criteria; [49 CFR 192.506(b)(4)]

5. remediation methods for assessment findings; [49 CFR 192.506(b)(5)]

6. spike hydrostatic pressure test monitoring and acceptance procedures, if used; [49 CFR 192.506(b)(6)]

7. procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and [49 CFR 192.506(b)(7)]

8. evidence of a review of all procedures and assessments by a qualified technical subject matter expert. [49 CFR 192.506(b)(8)]

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 46:1588 (November 2020).

§2307. Test Requirements for Pipelines to Operate at a Hoop Stress Less Than 30 Percent of SMYS and at or above 100 psi (689 kPa) Gauge [49 CFR 192.507]

A. Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 psi (689 kPa) gage must be tested in accordance with the following. [49 CFR 192.507]

1. The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested. [49 CFR 192.507(a)]

2. If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium: [49 CFR 192.507(b)]

a. a leak test must be made at a pressure between 100 psi (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or [49 CFR 192.507(b)(1)]

b. the line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS. [49 CFR 192.507(b)(2)]

3. The pressure must be maintained at or above the test pressure for at least one hour. [49 CFR 192.507(c)]

4. For fabricated units and short sections of pipe, for which a post installation test is impractical, a pre-installation hydrostatic pressure test must be conducted in accordance with the requirements of this Section. [49 CFR 192.507(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 9:238 (April 1983), amended LR 10:530 (July 1984), LR 27:1545 (September 2001), LR 30:1257 (June 2004), LR. 47:1145 (August 2021).

§2309. Test Requirements for Pipelines to Operate below 100 psi (689 kPa) Gauge [49 CFR 192.509]

A. Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 psi (689 kPa) gage must be leak tested in accordance with the following. [49 CFR 192.509]

1. The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested. [49 CFR 192.509(a)]

2. Each main that is to be operated at less than 1 psi (6.9 kPa) gage must be tested to at least 10 psi (69 kPa) gage and each main to be operated at or above 1 psi (6.9 kPa) gage must be tested to at least 90 psi (621 kPa) gage. [49 CFR 192.509(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 9:238 (April 1983), amended LR 10:530 (July 1984), LR 27:1546 (September 2001), LR 30:1257 (June 2004).

§2311. Test Requirements for Service Lines [49 CFR 192.511]

A. Each segment of a service line (other than plastic) must be leak tested in accordance with this Section before being placed in service. If feasible, the service-line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service. [49 CFR 192.511(a)]

B. Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 psi (6.9 kPa) gage but not more than 40 psi (276 kPa) gage must be given a leak test at a pressure of not less than 50 psi (345 kPa) gage. [49 CFR 192.511(b)]

C. Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 psi (276 kPa) gage must be tested to at least 90 psi (621 kPa) gage, except that each segment of the steel service line stressed to 20 percent or more of SMYS must be tested in accordance with §2307 of this Chapter. [49 CFR 192.511(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 9:238 (April 1983), amended LR 10:530 (July 1984), LR 27:1546 (September 2001), LR 30:1257 (June 2004).

§2313. Test Requirements for Plastic Pipelines [49 CFR 192.513]

A. Each segment of a plastic pipeline must be tested in accordance with this Section. [49 CFR 192.513(a)]

B. The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested. [49 CFR 192.513(b)]

C. The test pressure must be at least 150 percent of the maximum operating pressure or 50 psi (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under §921, at a temperature not less than the pipe temperature during the test. [49 CFR 192.513(c)]

D. During the test, the temperature of thermoplastic material may not be more than 100°F (38°C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater. [49 CFR 192.513(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 9:238 (April 1983), amended LR 10:530 (July 1984), LR 24:1312 (July 1998), LR 27:1546 (September 2001), LR 30:1257 (June 2004), LR 46:1588 (November 2020).

§2315. Environmental Protection and Safety Requirements [49 CFR 192.515]

A. In conducting tests under this Chapter, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure. [49 CFR 192.515(a)]

B. The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment. [49 CFR 192.515(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 9:238 (April 1983), amended LR 10:531 (July 1984), LR 30:1258 (June 2004).

§2317. Records [49 CFR 192.517]

A. An operator must make, and retain for the useful life of the pipeline, a record of each test performed under §§2305, 2306 and 2307. The record must contain at least the following information: [49 CFR 192.517(a)]

1. the operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used; [49 CFR 192.517(a)(1)]

2. test medium used; [49 CFR 192.517(a)(2)]

3. test pressure; [49 CFR 192.517(a)(3)]

4. test duration; [49 CFR 192.517(a)(4)]

5. pressure recording charts, or other record of pressure readings; [49 CFR 192.517(a)(5)]

6. elevation variations, whenever significant for the particular test; [49 CFR 192.517(a)(6)]

7. leaks and failures noted and their disposition. [49 CFR 192.517(a)(7)]

B. Each operator must maintain a record of each test required by §§2309, 2311, and 2313 for at least five years. [49 CFR 192.517(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 9:238 (April 1983), amended LR 10:531 (July 1984), LR 30:1258 (June 2004), LR 46:1588 (November 2020).

Chapter 25. Uprating [Subpart K]

§2501. Scope [49 CFR 192.551]

A. This Chapter prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines. [49 CFR 192.551]

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 9:239 (April 1983), amended LR 10:531 (July 1984), LR 30:1258 (June 2004).

§2503. General Requirements [49 CFR 192.553]

A. Pressure Increases. Whenever the requirements of this Chapter require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled, and in accordance with the following. [49 CFR 192.553(a)]

1. At the end of each incremental increase, the pressure must be held constant while the entire segment of the pipeline that is affected is checked for leaks. [49 CFR 192.553(a)(1)]

2. Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous. [49 CFR 192.553(a)(2)]

B. Records. Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this Chapter, of all work performed, and of each pressure test conducted, in connection with the uprating. [49 CFR 192.553(b)]

C. Written Plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this Chapter is complied with. [49 CFR 192.553(c)]

D. Limitation on Increase in Maximum Allowable Operating Pressure. Except as provided in §2505.C, a new maximum allowable operating pressure established under this Chapter may not exceed the maximum that would be allowed under §§2719 and 2721 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (§905) is unknown, the MAOP may be increased as provided in §2719.A.1. [49 CFR 192.553(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 9:239 (April 1983), amended LR 10:531 (July 1984), LR 24:1312 (July 1998), LR 30:1258 (June 2004).

§2505. Uprating to a Pressure That Will Produce a Hoop Stress of 30 Percent or More of SMYS in Steel Pipelines [49 CFR 192.555]

A. Unless the requirements of this Section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure. [49 CFR 192.555(a)]

B. Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall: [49 CFR 192.555(b)]

1. review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this Subpart; and [49 CFR 192.555(b)(1)]

2. make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure. [49 CFR 192.555(b)(2)]

C. After complying with Subsection B of this Section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under §2719, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation). [49 CFR 192.555(c)]

D. After complying with Subsection B of this Section, an operator that does not qualify under Subsection C of this Section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met. [49 CFR 192.555(d)]

1. The segment of pipeline is successfully tested in accordance with the requirements of this Subpart for a new line of the same material in the same location. [49 CFR 192.555(d)(1)]

2. An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if: [49 CFR 192.555(d)(2)]

a. it is impractical to test it in accordance with the requirements of this Subpart; [49 CFR 192.555(d)(2)(i)]

b. the new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and [49 CFR 192.555(d)(2)(ii)]

c. the operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this Subpart. [49 CFR 192.555(d)(2)(iii)]

E. Where a segment of pipeline is uprated in accordance with Subsection C or Paragraph D.2 of this Section, the increase in pressure must be made in increments that are equal to: [49 CFR 192.555(e)]

1. 10 percent of the pressure before the uprating; or [49 CFR 192.555(e)(1)]

2. 25 percent of the total pressure increase, whichever produces the fewer number of increments. [49 CFR 192.555(e)(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 9:239 (April 1983), amended LR 10:531 (July 1984), LR 20:446 (April 1994), LR 30:1258 (June 2004).

§2507. Uprating: Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than 30 Percent of SMYS: Plastic, Cast Iron, and Ductile Iron Pipelines [49 CFR 192.557]

A. Unless the requirements of this Section have been met, no person may subject: [49 CFR 192.557(a)]

1. a segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or [49 CFR 192.557(a)(1)]

2. a plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure. [49 CFR 192.557(a)(2)]

B. Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall: [49 CFR 192.557(b)]

1. review the design, operating, and maintenance history of the segment of pipeline; [49 CFR 192.557(b)(1)]

2. make a leakage survey (if it has been more than one year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous; [49 CFR 192.557(b)(2)]

3. make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure; [49 CFR 192.557(b)(3)]

4. reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation; [49 CFR 192.557(b)(4)]

5. isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and [49 CFR 192.557(b)(5)]

6. if the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure. [49 CFR 192.557(b)(6)]

C. After complying with Subsection B of this Section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 psi (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of Paragraph B.6 of this Section apply, there must be at least two approximately equal incremental increases. [49 CFR 192.557(c)]

D. If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed. [49 CFR 192.557(d)]

1. In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill. [49 CFR 192.557(d)(1)]

2. Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three places where the cover is most likely to be greatest and shall use the greatest cover measured. [49 CFR 192.557(d)(2)]

3. Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table. [49 CFR 192.557(d)(3)]

	Allowance (inches)(millimeters)		
	Cast Iron Pipe		
Pipe Size (inches) (millimeters)	Pit Cast Pipe	Centrifugally Cast Pipe	Ductile Iron Pipe
3 to 8 (76 to 203)	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)	0.09 (2.29)		

4. For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of 11,000 psi (76 Mpa) gage and a modulus of rupture of 31,000 psi (214 Mpa) gage. [49 CFR 192.557(d)(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 9:239 (April 1983), amended LR 10:531 (July 1984), LR 18:857 (August 1992), LR 27:1546 (September 2001), LR 30:1259 (June 2004).

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

§2701. Scope [49 CFR 192.601]

A. This Chapter prescribes minimum requirements for the operation of pipeline facilities. [49 CFR 192.601]

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 9:240 (April 1983), amended LR 10:532 (July 1984), LR 30:1260 (June 2004).

§2703. General Provisions [49 CFR 192.603]

A. No person may operate a segment of pipeline unless it is operated in accordance with this Subpart. [49 CFR 192.603(a)]

B. Each operator shall keep records necessary to administer the procedures established under §2705. [49 CFR 192.603(b)]

C. The administrator or the state agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant state procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety. [49 CFR 192.603(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 9:240 (April 1983), amended LR 10:532 (July 1984), LR 18:857 (August 1992), LR 21:821 (August 1995), LR 24:1312 (July 1998), LR 30:1260 (June 2004), LR 44:1041 (June 2018).

§2705. Procedural Manual for Operations, Maintenance, and Emergencies [49 CFR 192.605]

A. General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted. [49 CFR 192.605(a)]

B. Maintenance and Normal Operations. The manual required by Subsection A of this Section must include procedures for the following, if applicable, to provide safety during maintenance and operations: [49 CFR 192.605(b)]

1. operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this Chapter and Chapter 29 of this Subpart; [49 CFR 192.605(b)(1)]

2. controlling corrosion in accordance with the operations and maintenance requirements of Chapter 21 of this Subpart; [49 CFR 192.605(b)(2)]

3. making construction records, maps, and operating history available to appropriate operating personnel; [49 CFR 192.605(b)(3)]

4. gathering of data needed for reporting incidents under Chapter 3 of Subpart 2 of this Part in a timely and effective manner; [49 CFR 192.605(b)(4)]

5. starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this Subpart, plus the build-up allowed for operation of pressure-limiting and control devices; [49 CFR 192.605(b)(5)]

6. maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service; [49 CFR 192.605(b)(6)]

7. starting, operating and shutting down gas compressor units; [49 CFR 192.605(b)(7)]

8. periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found; [49 CFR 192.605(b)(8)]

9. taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line; [49 CFR 192.605(b)(9)]

10. systematic and routine testing and inspection of pipe-type or bottle-type holders including: [49 CFR 192.605(b)(10)]

a. provision for detecting external corrosion before the strength of the container has been impaired; [49 CFR 192.605(b)(10)(i)]

b. periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and [49 CFR 192.605(b)(10)(ii)]

c. periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity; [49 CFR 192.605(b)(10)(iii)]

11. responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under §2715.A.3 specifically apply to these reports. [49 CFR 192.605(b)(11)]

12. implementing the applicable control room management procedures required by §2731. [49 CFR 192.605(b)(12)]

C. Abnormal Operation. For transmission lines, the manual required by Subsection A of this Section must include procedures for the following to provide safety when operating design limits have been exceeded: [49 CFR 192.605(c)]

1. responding to, investigating, and correcting the cause of: [49 CFR 192.605(c)(1)]

a. unintended closure of valves or shutdowns; [49 CFR 192.605(c)(1)(i)]

b. increase or decrease in pressure or flow rate outside normal operating limits; [49 CFR 192.605(c)(1)(ii)]

c. loss of communications; [49 CFR 192.605(c)(1)(iii)]

d. operation of any safety device; and [49 CFR 192.605(c)(1)(iv)]

e. any other foreseeable malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property; [49 CFR 192.605(c)(1)(v)]

2. checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation; [49 CFR 192.605(c)(2)]

3. notifying responsible operator personnel when notice of an abnormal operation is received; [49 CFR 192.605(c)(3)]

4. periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found; [49 CFR 192.605(c)(4)]

5. the requirements of Subsection C do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system. [49 CFR 192.605(c)(5)]

D. Safety-Related Condition Reports. The manual required by Subsection A of this Section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §323 of this Part. [49 CFR 192.605(d)]

E. Surveillance, Emergency Response, and Accident Investigation. The procedures required by §§2713.A, 2715, and 2717 must be included in the manual required by Subsection A of this Section. [49 CFR 192.605(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 9:240 (April 1983), amended LR 10:532 (July 1984), LR 21:822 (August 1995), LR 30:1260 (June 2004), LR 38:116 (January 2012).

§2707. Verification of Pipeline Material Properties and Attributes: Onshore Steel Transmission Pipelines. [49 CFR 192.607]

A. Applicability. Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this Section. [49 CFR 192.607(a)]

B. Documentation of Material Properties and Attributes. Records established under this Section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this Section needed to meet the requirements of the ECA method at §2724.C.3 or the fracture mechanics requirements at §2912 must be maintained for the life of the pipeline. [49 CFR 192.607(b)]

C. Verification of Material Properties and Attributes. If an operator does not have traceable, verifiable, and complete records required by Subsection B of this Section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following. [49 CFR 192.607(c)]

1. For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location. [49 CFR 192.607(c)(1)]

2. For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L. [49 CFR 192.607(c)(2)]

3. Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes. [49 CFR 192.607(c)(3)]

4. If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness. [49 CFR 192.607(c)(4)]

5. Verification of material properties and attributes for non-line pipe components must comply with Subsection F of this Section. [49 CFR 192.607(c)(5)]

D. Special requirements for nondestructive Methods. Procedures developed in accordance with Subsection C of this Section for verification of material properties and attributes using nondestructive methods must: [49 CFR 192.607(d)]

1. use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage; [49 CFR 192.607(d)(1)]

2. conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and [49 CFR 192.607(d)(2)]

3. use test equipment that has been properly calibrated for comparable test materials prior to usage. [49 CFR 192.607(d)(3)]

E. Sampling Multiple Segments of Pipe. To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements. [49 CFR 192.607(e)]

1. The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds two years, those segments cannot be considered as the same vintage for the purpose of defining a population under this Section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous. [49 CFR 192.607(e)(1)]

2. For each population defined according to Paragraph E.1 of this Section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, in situ evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to §2714, until completion of the lesser of the following: [49 CFR 192.607(e)(2)]

a. one excavation per mile rounded up to the nearest whole number; or [49 CFR 192.607(e)(2)(i)]

b. 150 excavations if the population is more than 150 miles. [49 CFR 192.607(e)(2)(ii)]

3. Prior tests conducted for a single excavation according to the requirements of Subsection C of this Section may be counted as one sample under the sampling requirements of this Subsection E. [49 CFR 192.607(e)(3)]

4. If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95 percent confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with §518. [49 CFR 192.607(e)(4)]

5. An operator may use an alternative statistical sampling approach that differs from the requirements specified in Paragraph E.2 of this Section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95 percent confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with §518. [49 CFR 192.607(e)(5)]

F. Components. For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with Subsection C of this Section for establishing and documenting the ANSI rating or pressure rating [in accordance with ASME/ANSI B16.5 (incorporated by reference, see §507)]. [49 CFR 192.607(f)]

1. Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline. [49 CFR 192.607(f)(1)]

2. Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are: [49 CFR 192.607(f)(2)]

a. larger than 2 inches in nominal outside diameter, [49 CFR 192.607(f)(2)(i)]

b. material grades of 42,000 psi (Grade X - 42) or greater, or [49 CFR 192.607(f)(2)(ii)]

c. appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures. [49 CFR 192.607(f)(2)(iii)]

3. Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination. [49 CFR 192.607(f)(3)]

G. Uprating. The material properties determined from the destructive or nondestructive tests required by this Section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of 24,000 psi in accordance with §907.B.2. [49 CFR 192.607(g)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 46:1588 (November 2020).

§2709. Change in Class Location: Required Study [49 CFR 192.609]

A. Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at a hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine: [49 CFR 192.609]

1. the present class location for the segment involved; [49 CFR 192.609(a)]

2. the design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this Subpart; [49 CFR 192.609(b)]

3. the physical condition of the segment to the extent it can be ascertained from available records; [49 CFR 192.609(c)]

4. the operating and maintenance history of the segment; [49 CFR 192.609(d)]

5. the maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and [49 CFR 192.609(e)]

6. the actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area. [49 CFR 192.609(f)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:240 (April 1983), amended LR 10:532 (July 1984), LR 30:1261 (June 2004).

§2711. Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure [49 CFR 192.611]

A. If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements. [49 CFR 192.611(a)]

1. If the segment involved has been previously tested in place for a period of not less than 8 hours: [49 CFR 192.611(a)(1)]

a. The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations. [49 CFR 192.611(a)(1)(i)]

b. The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §2720, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations. [49 CFR 192.611(a)(1)(ii)]

2. The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this Subpart for new segments of pipelines in the existing class location. [49 CFR 192.611(a)(2)]

3. The segment involved must be tested in accordance with the applicable requirements of Chapter 23 of this Subpart, and its maximum allowable operating pressure must then be established according to the following criteria. [49 CFR 192.611(a)(3)]

a. The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations. [49 CFR 192.611(a)(3)(i)]

b. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations. [49 CFR 192.611(a)(3)(ii)]

c. For pipeline operating at an alternative maximum allowable operating pressure per §2720, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations. [49 CFR 192.611(a)(3)(iii)]

B. The maximum allowable operating pressure confirmed or revised in accordance with this Section, may not exceed the maximum allowable operating pressure established before the confirmation or revision. [49 CFR 192.611(b)]

C. Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this Section does not preclude the application of §§2503 and 2505. [49 CFR 192.611(c)]

D. Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §2709 must be completed within 24 months of the change in class location. Pressure reduction under Subsections A.1 or A.2 of this Section within the 24-month period does not preclude establishing a maximum allowable operating pressure under Subsection A.3 of this Section at a later date. [49 CFR 192.611(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 9:241 (April 1983), amended LR 10:533 (July 1984), LR 18:858 (August 1992), LR 30:1261 (June 2004), LR 31:684 (March 2005), LR 35:2806 (December 2009).

§2712. Underwater Inspection and Reburial of Pipelines in the Gulf of Mexico and Its Inlets [49 CFR 192.612]

A. Each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005. [49 CFR 192.612(a)]

B. Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk. [49 CFR 192.612(b)]

C. If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall: [49 CFR 192.612(c)]

1. promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802, as well as Louisiana Pipeline Safety (225) 342-5505 (day or night), of the location and, if available, the geographic coordinates of that pipeline; [49 CFR 192.612(c)(1)]

2. promptly, but not later than seven days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and [49 CFR 192.612(c)(2)]

3. within six months after discovery, or not later than November 1 of the following year if the six month period is later than November 1 of the year of discovery, bury the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation: [49 CFR 192.612(c)(3)]

a. an operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial; [49 CFR 192.612(c)(3)(i)]

b. if an operator cannot obtain required state or federal permits in time to comply with this Section, it must notify OPS; specify whether the required permit is state or federal; and, justify the delay. [49 CFR 192.612(c)(3)(ii)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 18:858 (August 1992), LR 27:1546 (September 2001), LR 30:1262 (June 2004), LR 31:684 (March 2005).

§2713. Continuing Surveillance [49 CFR 192.613]

A. Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions. [49 CFR 192.613(a)]

B. If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §2719.A and B. [49 CFR 192.613(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 9:241 (April 1983), amended LR 10:533 (July 1984), LR 30:1262 (June 2004).

§2714. Damage Prevention Program [49 CFR 192.614]

A. Except as provided in Subsection D and E of this Section, each operator of a buried pipeline shall carry out, in accordance with this Section a written program to prevent damage to that pipeline by excavation activities. For the purpose of this Section, the term *excavation activities* include excavation, blasting, boring, tunneling, backfilling, the removal of above ground structures by either explosive or mechanical means, and other earth moving operations. [49 CFR 192.614(a)]

B. An operator may comply with any of the requirements of Subsection C of this Section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this Section. However, an operator must perform the duties of Paragraph C.3 of this Section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this Section, a one-call system is considered a *qualified one-call system* if it meets the requirements of Paragraph B.1 or B.2 of this Section: [49 CFR 192.614(b)]

1. the state has adopted a one-call damage prevention program under §198.37 of CFR 49; or [49 CFR 192.614(b)(1)]

2. the one-call system: [49 CFR 192.614(b)(2)]

a. is operated in accordance with §198.39 of CFR 49; [49 CFR 192.614(b)(2)(i)]

b. provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and [49 CFR 192.614(b)(2)(ii)]

c. assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline. [49 CFR 192.614(b)(2)(iii)]

C. The damage prevention program required by Subsection A of this Section must, at a minimum: [49 CFR 192.614(c)]

1. include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located; [49 CFR 192.614(c)(1)]

2. provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in Paragraph C.1 of this Section of the following as often as needed to make them aware of the damage prevention program: [49 CFR 192.614(c)(2)]

a. the program's existence and purpose; and [49 CFR 192.614(c)(2)(i)]

b. how to learn the location of underground pipelines before excavation activities are begun; [49 CFR 192.614(c)(2)(ii)]

3. provide a means of receiving and recording notification of planned excavation activities; [49 CFR 192.614(c)(3)]

4. if the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings; [49 CFR 192.614(c)(4)]

5. provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins; [49 CFR 192.614(c)(5)]

6. provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities: [49 CFR 192.614(c)(6)]

a. the inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and [49 CFR 192.614(c)(6)(i)]

b. in the case of blasting, any inspection must include leakage surveys. [49 CFR 192.614(c)(6)(ii)]

D. A damage prevention program under this Section is not required for the following pipelines: [49 CFR 192.614(d)]

1. pipelines located offshore; [49 CFR 192.614(d)(1)]

2. pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995; [49 CFR 192.614(d)(2)]

3. pipelines to which access is physically controlled by the operator. [49 CFR 192.614(d)(3)]

E. Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following: [49 CFR 192.614(e)]

1. the requirements of Subsection A of this Section that the damage prevention program be written; and [49 CFR 192.614(e)(1)]

2. the requirements of Paragraph C.1 and C.2 of this Section. [49 CFR 192.614(e)(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 9:241 (April 1983), amended LR 10:533 (July 1984), LR 24:1312 (July 1998), LR 27:1547 (September 2001), LR 30:1262 (June 2004).

§2715. Emergency Plans [49 CFR 192.615]

A. Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following: [49 CFR 192.615(a)]

1. receiving, identifying, and classifying notices of events which require immediate response by the operator; [49 CFR 192.615(a)(1)]

2. establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials; [49 CFR 192.615(a)(2)]

3. prompt and effective response to a notice of each type of emergency, including the following: [49 CFR 192.615(a)(3)]

a. gas detected inside or near a building; [49 CFR 192.615(a)(3)(i)]

b. fire located near or directly involving a pipeline facility; [49 CFR 192.615(a)(3)(ii)]

c. explosion occurring near or directly involving a pipeline facility; [49 CFR 192.615(a)(3)(iii)]

d. natural disaster; [49 CFR 192.615(a)(3)(iv)]

4. the availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency; [49 CFR 192.615(a)(4)]

5. actions directed toward protecting people first and then property; [49 CFR 192.615(a)(5)]

6. emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property; [49 CFR 192.615(a)(6)]

7. making safe any actual or potential hazard to life or property; [49 CFR 192.615(a)(7)]

8. notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency; [49 CFR 192.615(a)(8)]

9. safely restoring any service outage; [49 CFR 192.615(a)(9)]

10. beginning action under §2717, if applicable, as soon after the end of the emergency as possible. [49 CFR 192.615(a)(10)]

11. actions required to be taken by a controller during an emergency in accordance with §2731. [49 CFR 192.615(a)(11)]

B. Each operator shall: [49 CFR 192.615(b)]

1. furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under Subsection A of this Section as necessary for compliance with those procedures; [49 CFR 192.615(b)(1)]

2. train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective; [49 CFR 192.615(b)(2)]

3. review employee activities to determine whether the procedures were effectively followed in each emergency. [49 CFR 192.615(b)(3)]

C. Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to: [49 CFR 192.615(c)]

1. learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency; [49 CFR 192.615(c)(1)]

2. acquaint the officials with the operator's ability in responding to a gas pipeline emergency; [49 CFR 192.615(c)(2)]

3. identify the types of gas pipeline emergencies of which the operator notifies the officials; and [49 CFR 192.615(c)(3)]

4. plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property. [49 CFR 192.615(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).

§2716. Public Awareness [49 CFR 192.616]

A. Except for an operator of a master meter or petroleum gas system covered under Subsection J of this Section, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (Incorporated by Reference, see §507). [49 CFR 192.616(a)]

B. The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities, Except as stated in Paragraph B.1 [49 CFR 192.616(b)].

1. Regulatory inspections are not an acceptable alternative to conducting an annual audit for measuring program implementation as mentioned in API RP 1162 section 8.3.

C. The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety [49 CFR 192.616(c)].

D. The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on (49 CFR 192.616(d)]:

1. use of a one-call notification system prior to excavation and other damage prevention activities [49 CFR 192.616(d)(1)];

2. possible hazards associated with unintended releases from a gas pipeline facility [49 CFR 192.616(d)(2)];

3. physical indications that such a release may have occurred [49 CFR 192.616(d)(3)];

4. steps that should be taken for public safety in the event of a gas pipeline release [49 CFR 192.616(d)(4)]; and

5. procedures for reporting such an event [49 CFR 192.616(d)(5)].

E. The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations [49 CFR 192.616(e)].

F. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas [49 CFR 192.616(f)].

G. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area [49 CFR 192.616(g)].

H. Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter or petroleum gas system covered under Subsection J of this Section must complete development of its written procedure by June 13, 2008. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate state agency. [49 CFR 192.616(h)]

I. The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies [49 CFR 192.616(i)].

J. Unless the operator transports gas as a primary activity, the operator of a master meter or petroleum gas system is not required to develop a public awareness program as prescribed in Subsections A through G of this Section. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter or petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include: [49 CFR 192.616(j)]

1. a description of the purpose and reliability of the pipeline; [49 CFR 192.616(j)(1)]

2. an overview of the hazards of the pipeline and prevention measures used; [49 CFR 192.616(j)(2)]

3. information about damage prevention; [49 CFR 192.616(j)(3)]

4. how to recognize and respond to a leak; and [49 CFR 192.616(j)(4)]

5. how to get additional information. [49 CFR 192.616(j)(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, LR 21:823 (August 1995), amended LR 30:1264 (June 2004), LR 33:480 (March 2007), LR 35:2807 (December 2009), 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. [49 CFR 192.617]

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. No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under Subsection C, D, or E of this Section, or the lowest of the following: [49 CFR 192.619(a)]

1. the design pressure of the weakest element in the segment, determined in accordance with Chapter 9 and 11 of this Subpart. However, for steel pipe in pipelines being converted under §514 or uprated under Chapter 25 of this Subpart, if any variable necessary to determine the design pressure under the design formula (§905) is unknown, one of the following pressures is to be used as design pressure: [49 CFR 192.619(a)(1)]

a. 80 percent of the first test pressure that produces yield under Section N5 of Appendix N of ASME B31.8 (incorporated by reference, see §507), reduced by the appropriate factor in Subparagraph A.2.b of this Section [49 CFR 192.619(a)(1)(i)]; or

b. if the pipe is 12 3/4 in. (324 mm) or less in outside diameter and is not tested to yield under this Subsection, 200 psi (1379 kPa) gage; [49 CFR 192.619(a)(1)(ii)]

2. the pressure obtained by dividing the pressure to which the pipeline segment was tested after construction as follows: [49 CFR 192.619(a)(2)]

a. for plastic pipe in all locations, the test pressure is divided by a factor of 1.5; [49 CFR 192.619(a)(2)(i)]

b. for steel pipe operated at 100 psi (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table to Subparagraph A.2.b. [49 CFR 192.619(a)(2)(ii)]

Table 1 to Subparagraph A.2.b

Factors[1], Segment

Class Location	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under CFR §192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1]For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

[2]For a component with a design pressure established in accordance with §1113.A or B installed after July 14, 2004, the factor is 1.3.

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	March 15, 2006, or	5 years preceding

Pipeline Segment	Pressure Date	Test Date
that first became subject to this Subpart (other than §2712) after April 13, 2006. —Onshore transmission line that was a gathering line not subject to this Subpart before March 15, 2006.	date line becomes subject to this Subpart, whichever is later.	applicable date in second column.
Offshore gathering lines.	July 1, 1976	July 1, 1971
All other pipelines.	July 1, 1970	July 1, 1965

4. the pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with §2707, if applicable, and the history of the segment, particularly known corrosion and the actual operating pressure. [49 CFR 192.619(a)(4)]

B. No person may operate a segment to which Paragraph A.4 of this Section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §1155. [49 CFR 192.619(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)].

D. The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §2720.B may elect to operate the segment at a maximum allowable operating pressure determined under §2720.A. [49 CFR 192.619(d)]

E. Notwithstanding the requirements in Subsections A through D of this Section, operators of onshore steel transmission pipelines that meet the criteria specified in §2724.A must establish and document the maximum allowable operating pressure in accordance with §2724. [49 CFR 192.619(e)]

F. Operators of onshore steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with Subsections A through E of this Section as follows: [49 CFR 192.619(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 192.607(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 192.607(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 192.607(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).

§2720. Alternative Maximum Allowable Operating Pressure for Certain Steel Pipelines [49 CFR 192.620]

A. *How does an operator calculate the alternative maximum allowable operating pressure?* An operator calculates the alternative maximum allowable operating pressure by using different factors in the same formulas used for calculating maximum allowable operating pressure under §2719.A as follows: [49 CFR 192.620(a)]

1. In determining the alternative design pressure under §905, use a design factor determined in accordance with §911.B, C, or D or, if none of these Subsections apply, in accordance with the following table: [49 CFR 192.620(a)(1)]

Class Location	Alternative design factor (F)
1	0.80
2	0.67
3	0.56

a. For facilities installed prior to December 22, 2008, for which §911.B, C, or D applies, use the following design factors as alternatives for the factors specified in those Subsections: §911.B–0.67 or less; 911.C and D–0.56 or less. [49 CFR 192.620(a)(1)(i)]

2. The alternative maximum allowable operating pressure is the lower of the following: [49 CFR 192.620(a)(2)]

a. the design pressure of the weakest element in the pipeline segment, determined under Chapters 9 and 11 of this Subpart; [49 CFR 192.620(a)(2)(i)]

b. the pressure obtained by dividing the pressure to which the pipeline segment was tested after construction by a factor determined in the following table: [49 CFR 192.620(a)(2)(ii)]

Class Location	Alternative Test Factor
1	1.25
2	[1]1.50
3	1.50

1 For Class 2 alternative maximum allowable operating pressure segments installed prior to December 22, 2008, the alternative test factor is 1.25.

B. *When may an operator use the alternative maximum allowable operating pressure calculated under Subsection A of this Section?* An operator may use an alternative maximum allowable operating pressure calculated under subsection A of this Section if the following conditions are met: [49 CFR 192.620(b)]

1. The pipeline segment is in a Class 1, 2, or 3 location; [49 CFR 192.620(b)(1)]

2. The pipeline segment is constructed of steel pipe meeting the additional design requirements in §912; [49 CFR 192.620(b)(2)]

3. A supervisory control and data acquisition system provides remote monitoring and control of the pipeline segment. The control provided must include monitoring of pressures and flows, monitoring compressor start-ups and shut-downs, and remote closure of valves per Subparagraph D.1.c of this Section; [49 CFR 192.620(b)(3)]

4. The pipeline segment meets the additional construction requirements described in §1728; [49 CFR 192.620(b)(4)]

5. The pipeline segment does not contain any mechanical couplings used in place of girth welds; [49 CFR 192.620(b)(5)]

6. If a pipeline segment has been previously operated, the segment has not experienced any failure during normal operations indicative of a systemic fault in material as determined by a root cause analysis, including metallurgical examination of the failed pipe. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operation at the alternative MAOP. An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and [49 CFR 192.620(b)(6)]

7. At least 95 percent of girth welds on a segment that was constructed prior to December 22, 2008, must have been non-destructively examined in accordance with §1323.B and C. [49 CFR 192.620(b)(7)]

C. *What is an operator electing to use the alternative maximum allowable operating pressure required to do?* If an operator elects to use the alternative maximum allowable operating pressure calculated under subsection A of this Section for a pipeline segment, the operator must do each of the following. [49 CFR 192.620(c)]

1. For pipelines already in service, notify the PHMSA pipeline safety regional office where the pipeline is in service of its election with respect to a segment at least 180 days before operating at the alternative MAOP. For new pipelines, notify the PHMSA pipeline safety regional office of planned alternative MAOP design and operation at least 60 days prior to the earliest start date of either pipe manufacturing or construction activities. An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state. [49 CFR 192.620(c)(1)]

2. Certify, by signature of a senior executive officer of the company, as follows: [49 CFR 192.620(c)(2)]

a. the pipeline segment meets the conditions described in Subsection B of this Section; and [49 CFR 192.620(c)(2)(i)]

b. the operating and maintenance procedures include the additional operating and maintenance requirements of Subsection D of this Section; and [49 CFR 192.620(c)(2)(ii)]

c. the review and any needed program upgrade of the damage prevention program required by Clause D.1.d.v of this Section has been completed. [49 CFR 192.620(c)(2)(iii)]

3. Send a copy of the certification required by Paragraph C.2 of this Section to each PHMSA pipeline safety regional office where the pipeline is in service 30 days prior to operating at the alternative MAOP. An operator must also send a copy to a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state. [49 CFR 192.620(c)(3)]

4. For each pipeline segment, do one of the following: [49 CFR 192.620(c)(4)]

a. perform a strength test as described in §2305 at a test pressure calculated under Subsection A of this Section; or [49 CFR 192.620(c)(4)(i)]

b. for a pipeline segment in existence prior to December 22, 2008, certify, under Paragraph C.2 of this Section, that the strength test performed under §2305 was conducted at a test pressure calculated under Subsection A of this Section, or conduct a new strength test in accordance with Subparagraph C.4.a of this Section. [49 CFR 192.620(c)(4)(ii)]

5. Comply with the additional operation and maintenance requirements described in Subsection D of this Section. [49 CFR 192.620(c)(5)]

6. If the performance of a construction task associated with implementing alternative MAOP that occurs after December 22, 2008, can affect the integrity of the pipeline segment, treat that task as a “covered task”, notwithstanding the definition in §3101.B and implement the requirements of Chapter 31 as appropriate. [49 CFR 192.620(c)(6)]

7. Maintain, for the useful life of the pipeline, records demonstrating compliance with Subsections B, C.6, and D of this Section. [49 CFR 192.620(c)(7)]

8. A Class 1 and Class 2 pipeline location can be upgraded one class due to class changes per §2711.A.3.a. All class location changes from Class 1 to Class 2 and from Class 2 to Class 3 must have all anomalies evaluated and remediated per: The ``original pipeline class grade'' §2720.D.1.k anomaly repair requirements; and all anomalies with a wall loss equal to or greater than 40 percent must be excavated and remediated. Pipelines in Class 4 may not operate at an alternative MAOP. [49 CFR 192.620(c)(8)]

D. What additional operation and maintenance requirements apply to operation at the alternative maximum allowable operating pressure? In addition to compliance with other applicable safety standards in this Part, if an operator establishes a maximum allowable operating pressure for a pipeline segment under Subsection A of this Section, an operator must comply with the additional operation and maintenance requirements as follows. [49 CFR 192.620(d)]

1. To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas (a–k): Take the following additional steps: [49 CFR 192.620(d)]

a. identifying and evaluating threats. Develop a threat matrix consistent with §3317 to do the following: [49 CFR 192.620(d)(1)]

i. identify and compare the increased risk of operating the pipeline at the increased stress level under this Section with conventional operation; and [49 CFR 192.620(d)(1)(i)]

ii. describe and implement procedures used to mitigate the risk; [49 CFR 192.620(d)(1)(ii)]

b. notifying the public: [49 CFR 192.620(d)(2)]

i. recalculate the potential impact circle as defined in §3303 to reflect use of the alternative maximum operating pressure calculated under Subsection A of this Section and pipeline operating conditions; and [49 CFR 192.620(d)(2)(i)]

ii. in implementing the public education program required under §2716, perform the following: [49 CFR 192.620(d)(2)(ii)]

(a). include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and [49 CFR 192.620(d)(2)(ii)(A)]

(b). include information about the integrity management activities performed under this Section within the message provided to the audience; [49 CFR 192.620(d)(2)(ii)(B)]

c. responding to an emergency in an area defined as a high consequence area in §3303: [49 CFR 192.620(d)(3)]

i. ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under Clause D.1.b.i of this Section; [49 CFR 192.620(d)(3)(i)]

ii. if personnel response time to mainline valves on either side of the high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control; [49 CFR 192.620(d)(3)(ii)]

iii. remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream; [49 CFR 192.620(d)(3)(iii)]

iv. a line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control; [49 CFR 192.620(d)(3)(iv)]

d. protecting the right-of-way: [49 CFR 192.620(d)(4)]

i. patrol the right-of-way at intervals not exceeding 45 days, but at least 12 times each calendar year, to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline: [49 CFR 192.620(d)(4)(i)]

ii. develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement; [49 CFR 192.620(d)(4)(ii)]

iii. if observed conditions indicate the possible loss of cover, perform a depth of cover study and replace cover as necessary to restore the depth of cover or apply alternative means to provide protection equivalent to the originally-required depth of cover; [49 CFR 192.620(d)(4)(iii)]

iv. use line-of-sight line markers satisfying the requirements of §2907.D except in agricultural areas, large water crossings or swamp, steep terrain, or where prohibited by Federal Energy Regulatory Commission orders, permits, or local law; [49 CFR 192.620(d)(4)(iv)]

v. review the damage prevention program under §2714.A in light of national consensus practices, to ensure the program provides adequate protection of the right-of-way. Identify the standards or practices considered in the review, and meet or exceed those standards or practices by incorporating appropriate changes into the program; [49 CFR 192.620(d)(4)(v)]

vi. develop and implement a right- of-way management plan to protect the pipeline segment from damage due to excavation activities; [49 CFR 192.620(d)(4)(vi)]

e. controlling internal corrosion: [49 CFR 192.620(d)(5)]

i. develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents; [192.620(d)(5)(i)]

ii. at points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and gas quality monitoring equipment. [49 CFR 192.620(d)(5)(ii)]

iii. Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling. [49 CFR 192.620(d)(5)(iii)]

iv. use cleaning pigs and sample accumulated liquids. Use inhibitors when corrosive gas or liquids are present. [49 CFR 192.620(d)(5)(iv)]

v. address deleterious gas stream constituents as follows: [49 CFR 192.620(d)(5)(v)] (a). limit carbon dioxide to 3 percent by volume; [49 192.620(d)(5)(v)(A)]

(b). allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and [49 CFR 192.620(d)(5)(v)(B)]

(c). limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas, where the hydrogen sulfide is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points; [49 CFR 192.620(d)(5)(v)(C)]

vi. review the program at least quarterly based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents; [49 CFR 192.620(d)(5)(vi)]

f. controlling interference that can impact external corrosion: [49 CFR 192.620(d)(6)]

i. prior to operating an existing pipeline segment at an alternate maximum allowable operating pressure calculated under this section, or within six months after placing a new pipeline segment in service at an alternate maximum allowable operating pressure calculated under this section, address any interference currents on the pipeline segment; [49 CFR 192.620(d)(6)(i)]

ii. to address interference currents, perform the following: [49 CFR 192.620(d)(6)(ii)]

(a). conduct an interference survey to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected; {49 CFR 192.620(d)(6)(ii)(A)]

(b). analyze the results of the survey; and [49 CFR 192.620(d)(6)(ii)(B)]

(c). take any remedial action needed within 6 months after completing the survey to protect the pipeline segment from deleterious current; [49 CFR 192.620(d)(6)(ii)(C)]

g. confirming external corrosion control through indirect assessment: [49 CFR 192.620(d)(7)]

i. within six months after placing the cathodic protection of a new pipeline segment in operation, or within six months after certifying a segment under §2720.C.1 of an existing pipeline segment under this Section, assess the adequacy of the cathodic protection through an indirect method such as close- interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG); [49 CFR 192.620(d)(7)(i)]

ii. remediate any construction damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35 percent for DCVG or 50 dB[mu]v for ACVG) under section 4 of NACE RP-0502-2002 (incorporated by reference, see §507); [49 CFR 192.620(d)(7)(ii)]

iii. within six months after completing the baseline internal inspection required under Subparagraph D.1.i of this Section, integrate the results of the indirect assessment required under Clause D.1.g.i of this Section with the results of the baseline internal inspection and take any needed remedial actions; [49 CFR 192.620(d)(7)(iii)]

iv. for all pipeline segments in high consequence areas, perform periodic assessments as follows: [49 CFR 192.620(d)(7)(iv)]

(a). conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under Chapter 33 of this Subpart; [49 CFR 192.620(d)(7)(iv)(A)]

(b). locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area, if practicable; [49 CFR 192.620(d)(7)(iv)(B)]

(c). integrate the results with those of the baseline and periodic assessments for integrity done under Subparagraphs D.1.i and D.1.j of this Section; [49 CFR 192.620(d)(7)(iv)(C)]

h. controlling external corrosion through cathodic protection: [49 CFR 192.620(d)(8)]

i. if an annual test station reading indicates cathodic protection below the level of protection required in Chapter 21 of this Subpart, complete remedial action within six months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service demonstrating that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state; and [49 CFR 192.620(d)(8)(i)]

ii. after remedial action to address a failed reading, confirm restoration of adequate corrosion control by a close interval survey on either side of the affected test station to the next test station unless the reason for the failed reading is determined to be a rectifier connection or power input problem that can be remediated and otherwise verified; [49 CFR 192.620(d)(8)(ii)]

iii. if the pipeline segment has been in operation, the cathodic protection system on the pipeline segment must have been operational within 12 months of the completion of construction; [49 CFR 192.620(d)(8)(iii)]

i. conducting a baseline assessment of integrity; [49 CFR 192.620(d)(9)]

i. except as provided in Clause D.1.i.iii of this Section, for a new pipeline segment operating at the new alternative maximum allowable operating pressure, perform a baseline internal inspection of the entire pipeline segment as follows: [49 CFR 192.620(d)(9)(i)]

(a). assess using a geometry tool after the initial hydrostatic test and backfill and within six months after placing the new pipeline segment in service; and [49 CFR 192.620(d)(9)(i)(A)]

(b). assess using a high resolution magnetic flux tool within three years after placing the new pipeline segment in service at the alternative maximum allowable operating pressure; [49 CFR 192.620(d)(9)(i)(B)]

ii. except as provided in Clause D.1.i.iii of this Section, for an existing pipeline segment, perform a baseline internal assessment using a geometry tool and a high resolution magnetic flux tool before, but within two years prior to, raising pressure to the alternative maximum allowable operating pressure as allowed under this Section; [49 CFR 192.620(d)(9)(ii)]

iii. if headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a pipeline segment operating at alternative maximum allowable operating pressure cannot accommodate a geometry tool and a high resolution magnetic flux tool, use direct assessment (per §3325, §3327 and/or §3329) or pressure testing (per Chapter 23 of this Subpart) to assess that portion; [49 CFR 192.620(d)(9)(iii)]

j. conducting periodic assessments of integrity: [49 CFR 192.620(d)(10)]

i. determine a frequency for subsequent periodic integrity assessments as if all the alternative maximum allowable operating pressure pipeline segments were covered by Chapter 33 of this Subpart; and [49 CFR 192.620(d)(10)(i)]

ii. conduct periodic internal inspections using a high resolution magnetic flux tool on the frequency determined under Clause D.1.j.i of this Section; or [49 CFR 192.620(d)(10)(ii)]

iii. use direct assessment (per §3325, §3327 and/ or §3329) or pressure testing (per Chapter 23 of this Subpart) for periodic assessment of a portion of a segment to the extent permitted for a baseline assessment under Clause D.1.i.iii of this Section;

k. making repairs: [49 CFR 192.620(d)(11)]

i. perform the following when evaluating an anomaly: [49 CFR 192.620(d)(11)(i)]

(a). use the most conservative calculation for determining remaining strength or an alternative validated calculation based on pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature: and [49 CFR 192.620(d)(11)(i)(A)]

(b). take into account the tolerances of the tools used for the inspection; [49 CFR 192.620(d)(11)(i)(B)]

ii. repair a defect immediately if any of the following apply: [49 CFR 192.620(d)(11)(ii)]

(a). the defect is a dent discovered during the baseline assessment for integrity under Subparagraph D.1.i of this Section and the defect meets the criteria for immediate repair in §1709.B; [49 CFR 192.620(d)(11)(ii)(A)]

(b). the defect meets the criteria for immediate repair in §3333.D; [49 CFR 192.620(d)(11)(ii)(B)]

(c). the alternative maximum allowable operating pressure was based on a design factor of 0.67 under Subsection A of this Section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure; [49 CFR 192.620(d)(11)(ii)(C)]

(d). the alternative maximum allowable operating pressure was based on a design factor of 0.56 under Subsection A of this Section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure; [49 CFR 192.620(11)(ii)(D)]

iii. if Clause D.1.k.ii of this Section does not require immediate repair, repair a defect within one year if any of the following apply: [49 CFR 192.620(d)(11)(iii)]

(a). the defect meets the criteria for repair within one year in §3333.D; [49 CFR 192.620(d)(11)(iii)(A)]

(b). the alternative maximum allowable operating pressure was based on a design factor of 0.80 under Subsection A of this Section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure; [49 CFR 192.620(d)(11)(iii)(B)]

(c). the alternative maximum allowable operating pressure was based on a design factor of 0.67 under Subsection A of this Section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure; [49 CFR 192.620(d)(11)(iii)(C)]

(d). the alternative maximum allowable operating pressure was based on a design factor of 0.56 under Subsection A of this Section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure; [49 CFR 192.620(d)(11)(iii)(D)]

iv. evaluate any defect not required to be repaired under Clause D.1.k.ii or iii of this Section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re- inspect within that interval. [49 CFR 192.620(d)(11)(iv)]

E. Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure? Notwithstanding the required capacity of pressure relieving and limiting stations otherwise required by §1161, if an operator establishes a maximum allowable operating pressure for a pipeline segment in accordance with Subsection A of this Section, an operator must: [49 CFR 192.620(e)]

1. provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and [49 CFR 192.620(e)(1)]

2. develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system. [49 CFR 192.620(e)(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 35:2807 (December 2009), amended LR 38:117 (January 2012), repromulgated LR 38:828 (March 2012), amended LR 44:1041 (June 2018).

§2721. Maximum Allowable Operating Pressure: High-Pressure Distribution Systems [49 CFR 192.621]

A. No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable: [49 CFR 192.621(a)]

1. the design pressure of the weakest element in the segment, determined in accordance with Chapter 9 and 11 of this Subpart; [49 CFR 192.621(a)(1)]

2. 60 psi (414 kPa) gage, for a segment of a distribution system otherwise designated to operate at over 60 psi (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of §1157.C; [49 CFR 192.621(a)(2)]

3. 25 psi (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints; [49 CFR 192.621(a)(3)]

4. the pressure limits to which a joint could be subjected without the possibility of its parting; [49 CFR 192.621(a)(4)]

5. the pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures. [49 CFR 192.621(a)(5)]

B. No person may operate a segment of pipeline to which Paragraph A.5 of this Section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §1155. [49 CFR 192.621(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 9:242 (April 1983), amended LR 10:535 (July 1984), LR 30:1264 (June 2004).

§2723. Maximum and Minimum Allowable Operating Pressure: Low-Pressure Distribution Systems [49 CFR 192.623]

A. No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment. [49 CFR 192.623(a)]

B. No person may operate a low-pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured. [49 CFR 192.623(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 9:243 (April 1983), amended LR 10:535 (July 1984), LR 30:1265 (June 2004).

§2724. Maximum Allowable Operating Pressure Reconfirmation: Onshore Steel Transmission Pipelines [49 CFR 192.624]

A. Applicability. Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this Section if either of the following conditions are met: [49 CFR 192.624(a)]

1. Records necessary to establish the MAOP in accordance with §2719.A.2, including records required by §2317.A, are not traceable, verifiable, and complete and the pipeline is located in one of the following locations: [49 CFR 192.624(a)(1)]

a. a high consequence area as defined in § 3303; or [49 CFR 192.624(a)(1)(i)]

b. a Class 3 or Class 4 location. [49 CFR 192.624(a)(1)(ii)]

2. The pipeline segment's MAOP was established in accordance with §2719.C, the pipeline segment's MAOP is greater than or equal to 30 percent of the specified minimum yield strength, and the pipeline segment is located in one of the following areas: [49 CFR 192.624(a)(2)]

a. a high consequence area as defined in §3303; [49 CFR 192.624(a)(2)(i)]

b. a Class 3 or Class 4 location; or [49 CFR 192.607(a)(2)(ii)]

c. a moderate consequence area as defined in §503, if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools. [49 CFR 192.624(a)(2)(iii)]

B. Procedures and Completion Dates. Operators of a pipeline subject to this Section must develop and document procedures for completing all actions required by this Section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of §2724.A, and for performing a spike test or material verification in accordance with §§2306 and 2707, if applicable. All actions required by this Section must be completed according to the following schedule. [49 CFR 192.624(b)]

1. Operators must complete all actions required by this Section on at least 50 percent of the pipeline mileage by July 3, 2028. [49 CFR 192.624(b)(1)]

2. Operators must complete all actions required by this Section on 100 percent of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed four years after the pipeline segment first meets a condition of §2724.A (e.g., due to a location becoming a high consequence area), whichever is later. [49 CFR 192.624(b)(2)]

3. If operational and environmental constraints limit an operator from meeting the deadlines in §2724, the operator may petition for an extension of the completion deadlines by up to 1 year, upon submittal of a notification in accordance with §518. The notification must include an up-to-date plan for completing all actions in accordance with this Section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety. [49 CFR 192.624(b)(3)]

C. Maximum allowable operating pressure determination. Operators of a pipeline segment meeting a condition in Subsection A of this Section must reconfirm its MAOP using one of the following methods. [49 CFR 192.624(c)]

1. Method 1: Pressure test. Perform a pressure test and verify material properties records in accordance with §2707 and the following requirements. [49 CFR 192.624(c)(1)]

a. Pressure Test. Perform a pressure test in accordance with Chapter 23 of this Subpart. The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in §2719.A.2.b. [49 CFR 192.624(c)(1)(i)]

b. Material Properties Records. Determine if the following material properties records are documented in traceable, verifiable, and complete records: Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength). [49 CFR 192.624(c)(1)(ii)]

c. Material Properties Verification. If any of the records required by Subparagraph C.1.b of this Section are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with §2707. An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with §2707. [49 CFR 192.624(c)(1)(iii)]

2. Method 2: Pressure Reduction. Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the five years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in §2719.A.2.b. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during a continuous 30-day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (i.e., the location-specific operating pressure at each location). [49 CFR 192.624(c)(2)]

a. Where the pipeline segment has had a class location change in accordance with §2711, and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows. [49 CFR 192.624(c)(2)(i)]

i. For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the five years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4. [49 CFR 192.624(c)(2)(i)(A)]

ii. For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the five years preceding October 1, 2019, divided by 2.00. [49 CFR 192.624(c)(2)(i)(B)]

b. Future uprating of the pipeline segment in accordance with Chapter 25 is allowed if the MAOP is established using Method 2. [49 CFR 192.624(c)(2)(ii)]

c. If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with §518 no later than seven calendar days after establishing the reduced MAOP. The notification must include the following details: [49 CFR 192.624(c)(2)(iii)]

i. descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in § 2724.C.2; [49 CFR 192.624(c)(2)(iii)(A)]

ii. the fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 2912; [49 CFR 192.624(c)(2)(iii)(B)]

iii. justification that establishing MAOP by another method allowed by this Section is impractical; [49 CFR 192.624(c)(2)(iii)(C)]

iv. justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance § 2707, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and [49 CFR 192.624(c)(2)(iii)(D)]

v. planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts. [49 CFR 192.624(c)(2)(iii)(E)]

3. Engineering Critical Assessment (ECA). Conduct an ECA in accordance with §2732. [49 CFR 192.624(c)(3)]

4. Method 4: Pipe Replacement. Replace the pipeline segment in accordance with this Part. [49 CFR 192.624(c)(4)]

5. Method 5: Pressure reduction for pipeline segments with small potential impact radius. pipelines with a potential impact radius (PIR) less than or equal to 150 feet may establish the MAOP as follows: [49 CFR 192.624(c)(5)]

a. reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during 5 years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (i.e., the location specific operating pressure at each location); [49 CFR 192.624(c)(5)(i)]

b. Conduct patrols in accordance with §2905.A and C and conduct instrumented leakage surveys in accordance with §2906 at intervals not to exceed those in the following table 1 to §2724.C.5.b: [49 CFR 192.624(c)(5)(ii)]

Table 1 to §2724.C.5.b		
Class Locations	**Patrols**	**Leakage Surveys**
Class 1 and Class 2	3 1⁄2 months, but at least four times each calendar year	3 1⁄2 months, but at least four times each calendar year.
Class 3 and Class 4	3 months, but at least six times each calendar year .	3 months, but at least six times each calendar year.

c. Under Method 5, future uprating of the pipeline segment in accordance with Chapter 25 is allowed. [49 CFR 192.624(c)(5)(iii)]

6. Method 6: Alternative Technology. Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with §518. The notification must include descriptions of the following details: [49 CFR 192.624(c)(6)]

a. the technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated; [49 CFR 192.624(c)(6)(i)]

b. procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered; [49 CFR 192.624(c)(6)(ii)]

c. pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization; [49 CFR 192.624(c)(6)(iii)]

d. assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength; [49 CFR 192.624(c)(6)(iv)]

e. if any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with Section § 2912; [49 CFR 192.624(c)(6)(v)]

f. operational monitoring procedures; [49 CFR 192.624(c)(6)(vi)]

g. methodology and criteria used to justify and establish the MAOP; and [49 CFR 192.624(c)(6)(vii)]

h. documentation of the operator's process and procedures used to implement the use of the alternative technology, including any records generated through its use. [49 CFR 192.624(c)(6)(viii)]

D. Records. An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this Section for the life of the pipeline. [49 CFR 192.624(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 46:1590 (November 2020).

§2725. Odorization of Gas [49 CFR 192.625]

A. No person engaged in the business of handling, storing, selling, or distributing natural and other toxic or combustible odorless gases, except liquefied petroleum gases, shall operate a gathering, distribution or transmission pipeline, unless the gas is malodorized in accordance with this regulation.

B. Natural gas or any toxic or combustible odorless gas, in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell at any point in the line where odorization is required. [49 CFR 192.625(a)]

C. Natural gas, or any toxic or combustible odorless gas, in a gathering or transmission line in a Class 3 or Class 4 location must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell at any point in the line where odorization is required, unless: [49 CFR 192.625(b)]

1. at least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location; [49 CFR 192.625(b)(1)]

2. the line transports gas to any of the following facilities: [49 CFR 192.625(b)(2)]

a. an underground storage field; [49 CFR 192.625(b)(2)(i)]

b. a gas processing plant; [49 CFR 192.625(b)(2)(ii)]

c. a gas dehydration plant; or [49 CFR 192.625(b)(2)(iii)]

d. an industrial plant using gas in a process where the presence of an odorant: [49 CFR 192.625(b)(2)(iv)]

i. makes the end product unfit for the purpose for which it is intended; [49 CFR 192.625(b)(2)(iv)(A)]

ii. reduces the activity of a catalyst; or [49 CFR 192.625(b)(2)(iv)(B)]

iii. reduces the percentage completion of a chemical reaction; [49 CFR 192.625(b)(2)(iv)(C)]

3. in the case of a lateral line which transports gas to a distribution center or industrial complex, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or [49 CFR 192.625(b)(3)]

4. the combustible gas is hydrogen intended for use as a feedstock in a manufacturing process. [49 CFR 192.625(b)(4)]

D. In the case of a farm tap location on a gathering, transmission or distribution system, it shall be the responsibility of the person(s) selling natural gas to the end user through such farm tap to odorize the natural gas in accordance with this regulation.

E. If gas is delivered into facilities which would be exempt by Subsection C, and this exempt gas is also being used in one of the facilities for space heating, refrigeration, water heating, cooking and other domestic uses, or if such gas is used for furnishing heat, or air conditioning for office or living quarters, the end user of such gas shall malodorize it in accordance with these regulations.

F. In the concentrations in which it is used, the malodorant in combustible gases must comply with the following. [49 CFR 192.625(c)]

1. The malodorant may not be deleterious to persons, materials, or pipe. [49 CFR 192.625(c)(1)]

2. The products of combustion from the malodorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed. [49 CFR 192.625(c)(2)]

G. The malodorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight. [49 CFR 192.625(d)]

H. Equipment for malodorization must introduce the malodorant without wide variations in the level of malodorant. The method of using malodorant and the containers and equipment used are subject to the approval of the commissioner of conservation and must meet the following requirements. [49 CFR 192.625(e)]

1. Malodorant must be detectable as specified in Subsection B at the most remote locations in the system.

2. Odorizing equipment may be of the wick type for systems handling 10,000 MCF/year or less. For systems handling over 10,000 MCF/year, absorption by-pass or liquid injection type must be used.

3. By-pass type odorizers must be equipped with a differential valve or orifice to create a differential sufficient to cause a flow of gas across the odorizer at minimum flow.

4. The flow through the odorizer is to be controlled by means of a flow control or metering valve located on the inlet side of the odorizer. The size of the valve shall be large enough to deliver sufficient by-passed gas across the odorizer during maximum flow periods to assure adequate odorization.

5. At the request of any gas company or affected person or upon the request of the Commissioner of Conservation, the Office of Conservation shall determine, after examination of any gas having a natural malodorant, the necessary rate of injection of additional malodorant, if any, which shall be necessary to meet the requirements of Subsection B.

6. The person subject to these rules must provide sufficient test points within each distribution system for use by the commissioner's staff to check the adequacy of odorization within the system. The test points must be of 1/4 inch threaded tap with pressure not to exceed 5 psi and located at remote locations approved by the commissioner.

I. Sampling Requirements

1. To assure the proper concentration of odorant in accordance with this Section, each operator (excluding farm taps) must conduct quarterly sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Farm taps must be sampled twice a calendar year, at least 6 months apart not to exceed 7.5 months. Operators of master meter systems and farm taps may comply with this requirement by: [49 CFR 192.625(f)]

a. receiving written verification from their gas source that the gas has the proper concentration of odorant (excluding farm taps); and [49 CFR 192.625(f)(1)]

b. conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant. [49 CFR 192.625(f)(2)]

2. Each person subject to these rules (excluding "master meter systems") shall record and retain on file for review by the Office of Conservation the following information:

a. the kind or kinds of malodorant agents introduced into such gas during the sampling period;

b. the quantity of each kind of malodorant agent used during each quarter. Reports on usage of odorant shall be made annually for farm taps; and

c. the quantity of gas odorized by each malodorant agent used during each quarter. Farm taps are exempt from this requirement.

3. In the event a person subject to these regulations shall fail to record and retain on file an odorization report or an odorization report which on its face shows non-compliance, the person may be put on remedial status after written notice of such status and be required to report odorization monthly within 30 days after the close of each month or for such other interval and for such period of time as shall be necessary to remedy the deficiencies in his odorization report or reports.

J. Persons who fail to comply with the provisions of this Part after January 1, 1983, shall be subject to the penalty provision contained in Act 754 in Louisiana Revised Statutes, Title 33:4525 or Louisiana Revised Statutes, Title 40:1896. The penalty specified in the cited provisions is $1,000 for each day of non-compliance therewith.

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 9:243 (April 1983), amended LR 10:535 (July 1984), LR 20:447 (April 1994), LR 21:823 (August 1995), LR 24:1312 (July 1998), LR 27:1548 (September 2001), LR 30:1265 (June 2004), LR 46:1592 (November 2020).

§2727. Tapping Pipelines under Pressure [49 CFR 192.627]

A. Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps. [49 CFR 192.627]

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 9:244 (April 1983), amended LR 10:536 (July 1984), LR 30:1266 (June 2004).

§2729. Purging of Pipelines [49 CFR 192.629]

A. When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas. [49 CFR 192.629(a)]

B. When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air. [49 CFR 192.629(b)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, LR 9:244 (April 1983), amended LR 10:536 (July 1984), LR 30:1266 (June 2004).

§2731. Control Room Management. [49 CFR 192.631]

A. General [49 CFR 192.631(a)]

1. This Section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this Section, except that for each control room where an operator's activities are limited to either or both of: [49 CFR 192.631(a)(1)]

a. distribution with less than 250,000 services; or [49 CFR 192.631(a)(1)(i)]

b. transmission without a compressor station, the operator must have and follow written procedures that implement only Subsections D (regarding fatigue), I (regarding compliance validation), and J (regarding compliance and deviations) of this Section. [49 CFR 192.631(a)(1)(ii)]

2. The procedures required by this Section must be integrated, as appropriate, with operating and emergency procedures required by §§2705 and 2715. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by Subsections and Paragraphs B, C.5, D.2, D.3, F and G of this Section must be implemented no later than October 1, 2011. The procedures required by Paragraphs C.1 through C.4, D.1, D.4, and E must be implemented no later than August 1, 2012. The training procedures required by Subsection H must be implemented no later than August 1, 2012, except that any training required by another Paragraph of this Section must be implemented no later than the deadline for that Paragraph. [49 CFR 192.631(a)(2)]

B. Roles and responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following: [49 CFR 192.631(b)]

1. a controller's authority and responsibility to make decisions and take actions during normal operations; [49 CFR 192.631(b)(1)]

2. a controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others; [49 CFR 192.631(b)(2)]

3. a controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others; [49 CFR 192.631(b)(3)]

4. a method of recording controller shift-changes and any hand-over of responsibility between controllers; and [49 CFR 192.631(b)(4)]

5. The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller. [49 CFR 192.631(b)(5)]

C. Provide Adequate Information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following: [49 CFR 192.631(c)]

1. implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference, see §507) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used; [49 CFR 192.631(c)(1)]

2. conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays; [49 CFR 192.631(c)(2)]

3. test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months; [49 CFR 192.631(c)(3)]

4. test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and [49 CFR 192.631(c)(4)]

5. establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged. [49 CFR 192.631(c)(5)]

D. Fatigue Mitigation. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined: [49 CFR 192.631(d)]

1. establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep; [49 CFR 192.631(d)(1)]

2. educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue; [49 CFR 192.631(d)(2)]

3. train controllers and supervisors to recognize the effects of fatigue; and [49 CFR 192.631(d)(3)]

4. establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility. [49 CFR 192.631(d)(4)]

E. Alarm Management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to: [49 CFR 192.631(e)]

1. review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations; [49 CFR 192.631(e)(1)]

2. identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities; [49 CFR 192.631(e)(2)]

3. verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed 15 months; [49 CFR 192.631(e)(3)]

4. review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan; [49 CFR 192.631(e)(4)]

5. monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and [49 CFR 192.631(e)(5)]

6. address deficiencies identified through the implementation of Paragraphs E.1 through E.5 of this Section. [49 CFR 192.631(e)(6)]

F. Change Management. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following: [49 CFR 192.631(f)]

1. establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration; [49 CFR 192.631(f)(1)]

2. require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and [49 CFR 192.631(f)(2)]

3. seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes. [49 CFR 192.631(f)(3)]

G. Operating Experience. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following: [49 CFR 192.631(g)]

1. review incidents that must be reported pursuant to Subpart 2 of this Part to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to: [49 CFR 192.631(g)(1)]

a. controller fatigue; [49 CFR 192.631(g)(1)(i)]

b. field equipment; [49 CFR 192.631(g)(1)(ii)]

c. the operation of any relief device; [49 CFR 192.631(g)(1)(iii)]

d. procedures; [49 CFR 192.631(g)(1)(iv)]

e. SCADA system configuration; and [49 CFR 192.631(g)(1)(v)]

f. SCADA system performance; [49 CFR 192.631(g)(1)(vi)]

2. include lessons learned from the operator's experience in the training program required by this Section. [49 CFR 192.631(g)(2)]

H. Training. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements: [49 CFR 192.631(h)]

1. responding to abnormal operating conditions likely to occur simultaneously or in sequence; [49 CFR 192.631(h)(1)]

2. use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions; [49 CFR 192.631(h)(2)]

3. training controllers on their responsibilities for communication under the operator's emergency response procedures; [49 CFR 192.631(h)(3)]

4. training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; [49 CFR 192.631(h)(4)]

5. for pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; [49 CFR 192.631(h)(5)]

6. control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018. [49 CFR 192.631(h)(6)]

I. Compliance Validation. Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a state, to the appropriate state agency. [49 CFR 192.631(i)]

J. Compliance and Deviations. An operator must maintain for review during inspection: [49 CFR 192.631(j)]

1. records that demonstrate compliance with the requirements of this Section; and [49 CFR 192.631(j)(1)]

2. documentation to demonstrate that any deviation from the procedures required by this Section was necessary for the safe operation of a pipeline facility. [49 CFR 192.631(j)(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 38:119 (January 2012), amended LR 44:1041 (June 2018).

§2732. Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore Steel Transmission Pipelines. [49 CFR 192.632]

A. When an operator conducts an MAOP reconfirmation in accordance with §2724.C.3 "Method 3" using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this Section. The ECA must assess: threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline. [49 CFR 192.632]

B. ECA Analysis [49 CFR 192.632(a)]

1. The material properties required to perform an ECA analysis in accordance with this Section are as follows: diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this Section are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with §2707. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this Section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by Chapter 21 of this Subpart, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§2717, 2910, and Chapter 33 of this Subpart. [49 CFR 192.632(a)(1)]

2. The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows. [49 CFR 192.632(a)(2)]

a. The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with § 2912. [49 CFR 192.632(a)(2)(i)]

b. The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, see §507) or R-STRENG (incorporated by reference, see §507) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth). [49 CFR 192.632(a)(2)(ii)]

c. When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented. [49 CFR 192.632(a)(2)(iii)]

d. If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using §2707. [49 CFR 192.632(a)(2)(iv)]

3. The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process. [49 CFR 192.632(a)(3)]

4. The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in §2719.A.2.b. [49 CFR 192.632(a)(4)]

C. Assessment to determine defects remaining in the pipe. An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with Subsection A of this Section. [49 CFR 192.632(b)]

1. An operator may use a previous pressure test that complied with Chapter 23 to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of Chapter 23 of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in accordance with §2912. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re- assessment interval in accordance with the methodology in §2912. [49 CFR 192.632(b)(1)]

2. Operators may use an inline inspection program in accordance with Subsection C of this Section. [49 CFR 192.632(b)(2)]

3. Operators may use "other technology" if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use "other technology" in the ECA, it must notify PHMSA in advance of using the other technology in accordance with §518. The "other technology" notification must have: [49 CFR 192.632(b)(3)]

a. descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and [49 CFR 192.632(b)(3)(i)]

b. procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered. [49 CFR 192.632(b)(3)(ii)]

D. In-line Inspection. An inline inspection (ILI) program to determine the defects remaining the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking. [49 CFR 192.632(c)]

1. If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots. [49 CFR 192.632(c)(1)]

2. If the pipeline has had a reportable incident, as defined in §303, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this Section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses. [49 CFR 192.632(c)(2)]

3. Inline inspection must be performed in accordance with §2145. [49 CFR 192.632(c)(3)]

4. An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to

conduct additional in-field examinations, reanalyze ILI data, or both. [49 CFR 192.632(c)(4)]

5. Interpretation and evaluation of assessment results must meet the requirements of §§2910, 2913, and Chapter 33 of this Subpart, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations. [49 CFR 192.632(c)(5)]

6. Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§2913 and 3333. [49 CFR 192.632(c)(6)]

E. Defect remaining life. If any pipeline segment contains cracking or may be susceptible to cracking or crack- like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with §2912. [49 CFR 192.632(d)]

F. Records. An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this Section for the life of the pipeline. [49 CFR 192.632(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 46:1593 (November 2020).

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

§2901. Scope [49 CFR 192.701]

A. This Chapter prescribes minimum requirements for maintenance of pipeline facilities. [49 CFR 192.701]

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 9:244 (April 1983), amended LR 10:536 (July 1984), LR 30:1266 (June 2004).

§2903. General [49 CFR 192.703]

A. No person may operate a segment of pipeline, unless it is maintained in accordance with this Chapter. [49 CFR 192.703(a)]

B. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. [49 CFR 192.703(b)]

C. Hazardous leaks must be repaired promptly. [49 CFR 192.703(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 9:244 (April 1983), amended LR 10:536 (July 1984), LR 30:1266 (June 2004).

§2905. Transmission Lines: Patrolling [49 CFR 192.705]

A. Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation. [49 CFR 192.705(a)]

B. The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table. [49 CFR 192.705(b)]

Maximum Interval between Patrols		
Class Location of Line	**At Highway and Railroad Crossings**	**At All Other Locations**
1, 2	7-1/2 months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3	4-1/2 months; but at least four times each calendar year.	7-1/2 months; but at least twice each calendar year.
4	4-1/2 months; but at least four times each calendar year.	4-1/2 months; but at least four times each calendar year.

C. Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way. [49 CFR 192.705(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 9:244 (April 1983), amended LR 10:536 (July 1984), LR 20:447 (April 1994), LR 24:1313 (July 1998), LR 27:1548 (September 2001), LR 30:1266 (June 2004).

§2906. Transmission Lines: Leakage Surveys [49 CFR 192.706]

A. Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §2725 without an odor or odorant, leakage surveys using leak detector equipment must be conducted: [49 CFR 192.706]

1. in Class 3 locations, at intervals not exceeding seven and one-half months, but at least twice each calendar year; and [49 CFR 192.706(a)]

2. in Class 4 locations, at intervals not exceeding four and one-half months, but at least four times each calendar year. [49 CFR 192.706(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 9:244 (April 1983), amended LR 10:536 (July 1984), LR:21:823 (August 1995), LR 30:1267 (June 2004).

§2907. Line Markers for Mains and Transmission Lines [49 CFR 192.707]

A. Buried Pipelines. Except as provided in Subsection B of this Section, a line marker must be placed and maintained as close as practical over each buried main and transmission line: [49 CFR 192.707(a)]

1. at each crossing of a public road and railroad; and [49 CFR 192.707(a)(1)]

2. wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference. [49 CFR 192.707(a)(2)]

B. Exceptions for Buried Pipelines. Line markers are not required for the following pipelines: [49 CFR 192.707(b)]

1. mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water; [49 CFR 192.707(b)(1)]

2. mains in Class 3 or Class 4 locations where a damage prevention program is in effect under §2714; [49 CFR 192.707(b)(2)]

3. transmission lines in Class 3 or 4 locations until March 20, 1996; or [49 CFR 192.707(b)(3)]

4. transmission lines in Class 3 or 4 locations where placement of a line marker is impractical. [49 CFR 192.707(b)(4)]

C. Pipelines Aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located above-ground in an area accessible to the public. [49 CFR 192.707(c)]

D. Marker Warning. The following must be written legibly on a background of sharply contrasting color on each line marker: [49 CFR 192.707(d)]

1. the word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with 1/4 inch (6.4 millimeters) stroke; [49 CFR 192.707(d)(1)]

2. the name of the operator and telephone number (including area code) where the operator can be reached at all times. [49 CFR 192.707(d)(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 9:244 (April 1983), amended LR 10:536 (July 1984), LR 24:1313 (July 1998), LR 27:1548 (September 2001), LR 30:1267 (June 2004).

§2909. Transmission Lines: Record Keeping [49 CFR 192.709]

A. Each operator shall maintain the following records for transmission lines for the periods specified. [49 CFR 192.709]

1. The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service. [49 CFR 192.709(a)]

2. The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least five years. However, repairs generated by patrols, surveys, inspections, or tests required by Chapters 27 and 29 of this Subpart must be retained in accordance with Paragraph A.3 of this Section. [49 CFR 192.709(b)]

3. A record of each patrol, survey, inspection, and test required by Chapters 27 and 29 of this Subpart must be retained for at least five years or until the next patrol, survey, inspection, or test is completed, whichever is longer. [49 CFR 192.709(c)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:245 (April 1983), amended LR 10:537 (July 1984), LR 24:1313 (July 1998), LR 30:1267 (June 2004).

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

A. Applicability

1. This Section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30 percent of the specified minimum yield strength and are located in: [49 CFR 192.710(a)]

a. a Class 3 or Class 4 location; or [49 CFR 192.710(a)(1)]

b. a moderate consequence area as defined in §503, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (i.e., "smart pig"). [49 CFR 192.710(a)(2)]

2. This Section does not apply to a pipeline segment located in a high consequence area as defined in §3303. [49 CFR 192.710(a)(3)]

B. General [49 CFR 192.710(b)]

1. Initial Assessment. An operator must perform initial assessments in accordance with this Section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of

§2910.A (e.g., due to a change in class location or the area becomes a moderate consequence area), whichever is later. [49 CFR 192.710(b)(1)]

2. Periodic Reassessment. An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety. [49 CFR 192.710(b)(2)]

3. Prior Assessment. An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the Chapter 33 requirements of Part VIII for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in Paragraph B.2 of this Section calculated from the date of the prior assessment. [49 CFR 192.710(b)(3)]

4. MAOP Verification. An integrity assessment conducted in accordance with the requirements of §2724.C for establishing MAOP may be used as an initial assessment or reassessment under this Section. [49 CFR 192.710(b)(4)]

C. Assessment Method. The initial assessments and the reassessments required by Subsection B of this Section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods. [49 CFR 192.710(c)]

1. internal inspection. Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (e.g., dents, gouges and grooves), material cracking and crack- like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with §2145; [49 CFR 192.710(c)(1)]

2. pressure test. Pressure test conducted in accordance with Chapter 23 of this Subpart. The use of Chapter 23 pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage; [49 CFR 192.710(c)(2)]

3. spike hydrostatic pressure test. A spike hydrostatic pressure test conducted in accordance with §2306. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects; [49 CFR 192.710(c)(3)]

4. direct examination. Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non- destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI); [49 CFR 192.710(c)(4)]

5. guided wave ultrasonic testing. guided wave ultrasonic testing (GWUT) as described in Appendix F; [49 CFR 192.710(c)(5)]

6. direct assessment. Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 3323 and with the applicable requirements specified in §§ 3325, 3327 and 3329; or [49 CFR 192.710(c)(6)]

7. other technology. Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with §518. [49 CFR 192.710(c)(7)]

D. Data Analysis. An operator must analyze and account for the data obtained from an assessment performed under Subsection C of this Section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies. [49 CFR 192.710(d)]

E. Discovery of Condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that 180 days is impracticable. [49 CFR 192.710(e)]

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

G. Analysis of Information. An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in Subsections A through F of this Section. [49 CFR 192.710(g)]

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

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

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

A. Temporary Repairs. Each operator shall take immediate temporary measures to protect the public whenever: [49 CFR 192.711(a)]

1. a leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and [49 CFR 192.711(a)(1)]

2. it is not feasible to make a permanent repair at the time of discovery. [49 CFR 192.711(a)(2)]

B. Permanent Repairs. An operator must make permanent repairs on its pipeline system according to the following.[49 CFR 192.711(b)]

1. Non Integrity Management Repairs. The operator must make permanent repairs as soon as feasible. [49 CFR 192.711(b)(1)]

2. Integrity Management Repairs. When an operator discovers a condition on a pipeline covered under Chapter 33-Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by §3333.D. [49 CFR 192.711(b)(2)]

C. Welded Patch. Except as provided in §2917.A.2.c, no operator may use a welded patch as a means of repair. [49 CFR 192.711(c)]

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

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

§2912. Analysis of Predicted Failure Pressure [49 CFR 192.712]

A. Applicability. Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this Section. [49 CFR 192.712(a)]

B. Corrosion Metal Loss. When analyzing corrosion metal loss under this Section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, see §507); R-STRENG (incorporated by reference, see §507); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result. [49 CFR 192.712(b)]

C. Reserved [49 CFR 192.712(c)]

D. Cracks and Crack-Like Defects [49 CFR 192.712(d)]

1. Crack Analysis Models. When analyzing cracks and crack-like defects under this Section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other). [49 CFR 192.712(d)(1)]

2. Analysis for Crack Growth and Remaining Life. If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure. [49 CFR 192.712(d)(2)]

a. When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in Paragraph E.2 of this Section must be used. [49 CFR 192.712(d)(2)(i)]

b. Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other). [49 CFR 192.712(d)(2)(ii)]

c. An operator must re-evaluate the remaining life of the pipeline before 50 percent of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50 percent of the remaining life calculated in the most recent evaluation has expired. [49 CFR 192.712(d)(2)(iii)]

3. Cracks that Survive Pressure Testing. For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the

methods in Paragraph D.1 of this Section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value: [49 CFR 192.712(d)(3)]

a. Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer; [49 CFR 192.712(d)(3)(i)]

b. a conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in §2707; [49 CFR 192.712(d)(3)(ii)]

c. a full size equivalent Charpy v- notch upper-shelf toughness level of 120 ft.-lbs.; or [49 CFR 192.712(d)(3)(iii)]

d. other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with §518. [49 CFR 192.712(d)(3)(iv)]

E. Data. In performing the analyses of predicted or assumed anomalies or defects in accordance with this Section, an operator must use data as follows. [49 CFR 192.712(e)]

1. An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using in situ direct measurements. [49 CFR 192.712(e)(1)]

2. The analyses performed in accordance with this Section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through §2707. Until documented material properties are available, the operator shall use conservative assumptions as follows. [49 CFR 192.712(e)(2)]

a. Material Toughness. An operator must use one of the following for material toughness: [49 CFR 192.712(e)(2)(i)]

i. Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer; [49 CFR 192.712(e)(2)(i)(A)]

ii. a conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in §2707; [49 CFR 192.712(e)(2)(i)(B)]

iii. if the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects; [49 CFR 192.712(e)(2)(i)(C)]

iv. if the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or [49 CFR 192.712(e)(2)(i)(D)]

v. other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with §518 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions. [49 CFR 192.712(e)(2)(i)(E)]

b. Material Strength. An operator must assume one of the following for material strength: [49 CFR 192.712(e)(2)(ii)]

i. Grade A pipe (30,000 psi), or [49 CFR 192.712(e)(2)(ii)(A)]

ii. The specified minimum yield strength that is the basis for the current maximum allowable operating pressure. [49 CFR 192.712(e)(2)(ii)(B)]

c. Pipe Dimensions and Other Data. Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 2707, the operator must use values upon which the current MAOP is based. [49 CFR 192.712(e)(2)(iii)]

F. Review. Analyses conducted in accordance with this Section must be reviewed and confirmed by a subject matter expert. [49 CFR 192.712(f)]

G. Records. An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this Section. Records must document justifications, deviations, and determinations made for the following, as applicable: [49 CFR 192.712(g)]

1. the technical approach used for the analysis; [49 CFR 192.712(g)(1)]

2. all data used and analyzed; [49 CFR 192.712(g)(2)]

3. pipe and weld properties; [49 CFR 192.712(g)(3)]

4. procedures used; [49 CFR 192.712(g)(4)]

5. evaluation methodology used; [49 CFR 192.712(g)(5)]

6. models used; [49 CFR 192.712(g)(6)]

7. direct in situ examination data; [49 CFR 192.712(g)(7)]

8. in-line inspection tool run information evaluated, including any multiple in-line inspection tool runs; [49 CFR 192.712(g)(8)]

9. pressure test data and results; [49 CFR 192.712(g)(9)]

10. in-the-ditch assessments; [49 CFR 192.712(g)(10)]

11. all measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results; [49 CFR 192.712(g)(11)]

12. all finite element analysis results; [49 CFR 192.712(g)(12)]

13. the number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method; [49 CFR 192.712(g)(13)]

14. the predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods; [49 CFR 192.712(g)(14)]

15. safety factors used for fatigue life and/or predicted failure pressure calculations; [49 CFR 192.712(g)(15)]

16. reassessment time interval and safety factors; [49 CFR 192.712(g)(16)]

17. the date of the review; [49 CFR 192.712(g)(17)]

18. confirmation of the results by qualified technical subject matter experts; and [49 CFR 192.712(g)(18)]

19. approval by responsible operator management personnel. [49 CFR 192.712(g)(19)]

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

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

§2913. Transmission Lines: Permanent Field Repair of Imperfections and Damages [49 CFR 192.713]

A. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be: [49 CFR 192.713(a)]

1. removed by cutting out and replacing a cylindrical piece of pipe; or [49 CFR 192.713(a)(1)]

2. repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. [49 CFR 192.713(a)(2)]

B. Operating pressure must be at a safe level during repair operations. [49 CFR 192.713(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 9:245 (April 1983), amended LR 10:537 (July 1984), LR 27:1548 (September 2001), LR 30:1268 (June 2004).

§2915. Transmission Lines: Permanent Field Repair of Welds [49 CFR 192.715]

A. Each weld that is unacceptable under §1321(c) must be repaired as follows. [49 CFR 192.715]

1. If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of §1325. [49 CFR 192.715(a)]

2. A weld may be repaired in accordance with §1325 while the segment of transmission line is in service if: [49 CFR 192.715(b)]

a. the weld is not leaking; [49 CFR 192.715(b)(1)]

b. the pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and [49 CFR 192.715(b)(2)]

c. grinding of the defective area can be limited so that at least 1/8 inch (3.2 millimeters) thickness in the pipe weld remains. [49 CFR 192.715(b)(3)]

3. A defective weld which cannot be repaired in accordance with Paragraph 1 or 2 of this Section must be repaired by installing a full encirclement welded split sleeve of appropriate design. [49 CFR 192.715(c)]

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

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

§2917. Transmission Lines: Permanent Field Repair of Leaks [49 CFR 192.717]

A. Each permanent field repair of a leak on a transmission line must be made by: [49 CFR 192.717]

1. removing the leak by cutting out and replacing a cylindrical piece of pipe; or [49 CFR 192.717(a)]

2. repairing the leak by one of the following methods: [49 CFR 192.717(b)]

a. install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS; [49 CFR 192.717(b)(1)]

b. if the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp; [49 CFR 192.717(b)(2)]

c. if the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (276 Mpa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size; [49 CFR 192.717(b)(3)]

d. if the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design; [49 CFR 192.717(b)(4)]

e. apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. [49 CFR 192.717(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, LR 9:245 (April 1983), amended LR 10:537 (July 1984), LR 27:1549 (September 2001), LR 30:1268 (June 2004).

§2919. Transmission Lines: Testing of Repairs [49 CFR 192.719]

A. Testing of Replacement Pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed. [49 CFR 192.719(a)]

B. Testing of Repairs Made by Welding. Each repair made by welding in accordance with §§2913, 2915, and 2917 must be examined in accordance with §1321. [49 CFR 192.719(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 9:245 (April 1983), amended LR 10:537 (July 1984), LR 30:1268 (June 2004).

§2920. Distribution Systems: Leak Repair [49 CFR 192.720]

A. Mechanical leak repair clamps installed after January 22, 2019 may not be used as a permanent repair method for plastic pipe. [49 CFR 192.720]

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 46:1597 (November 2020).

§2921. Distribution Systems: Patrolling [49 CFR 192.721]

A. The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety. [49 CFR 192.721(a)]

B. Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled: [49 CFR 192.721(b)]

1. in business districts, at intervals not exceeding 4 1/2 months, but at least four times each calendar year; and [49 CFR 192.721(b)(1)]

2. outside business districts, at intervals not exceeding seven and one-half months, but at least twice each calendar year. [49 CFR 192.721(b)(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 9:245 (April 1983), amended LR 10:537 (July 1984), LR 24:1313 (July 1998), LR 30:1268 (June 2004).

§2923. Distribution Systems: Leakage Surveys [49 CFR 192.723]

A. Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this Section. [49 CFR 192.723(a)]

B. The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements. [49 CFR 192.723(b)]

1. A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year. [49 CFR 192.723(b)(1)]

2. A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months. However, for cathodically unprotected distribution lines subject to § 2117.E on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months [49 CFR 192.723(b)(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 9:245 (April 1983), amended LR 10:537 (July 1984), LR 21:823 (August 1995), LR 24:1313 (July 1998), LR 30:1269 (June 2004), LR 31:685 (March 2005), LR 33:481 (March 2007).

§2925. Test Requirements for Reinstating Service Lines [49 CFR 192.725]

A. Except as provided in Subsection B of this Section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated. [49 CFR 192.725(a)]

B. Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested. [49 CFR 192.725(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 9:245 (April 1983), amended LR 10:538 (July 1984), LR 30:1269 (June 2004).

§2927. Abandonment or Deactivation of Facilities [49 CFR 192.727]

A. Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this Section. [49 CFR 192.727(a)]

B. Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard. [49 CFR 192.727(b)]

C. Except for service lines, each inactive pipeline that is not being maintained under this Subpart must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard. [49 CFR 192.727(c)]

D. Whenever service to a customer is discontinued, one of the following must be complied with. [49 CFR 192.727(d)]

1. The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. [49 CFR 192.727(d)(1)]

2. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly. [49 CFR 192.727(d)(2)]

3. The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed. [49 CFR 192.727(d)(3)]

E. If air is used for purging, the operator shall insure that a combustible mixture is not present after purging. [49 CFR 192.727(e)]

F. Each abandoned vault must be filled with a suitable compacted material. [49 CFR 192.727(f)]

G. For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. [49 CFR 192.727(g)]

1. The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at http://www.npms.phmsa.dot.gov or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001; fax (202) 366-4566; e-mail: InformationResourcesManager@PHMSA.dot.gov.

2. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws. [49 CFR 192.727(g)(1)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 9:245 (April 1983), amended LR 10:538 (July 1984), LR 21:824 (August 1995), LR 27:1549 (September 2001), LR 30:1269 (June 2004), LR 33:481 (March 2007), LR 35:2811 (December 2009).

§2931. Compressor Stations: Inspection and Testing of Relief Devices, [49 CFR 192.731]

A. Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§2939 and 2943, and must be operated periodically to determine that it opens at the correct set pressure. [49 CFR 192.731(a)]

B. Any defective or inadequate equipment found must be promptly repaired or replaced. [49 CFR 192.731(b)]

C. Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly. [49 CFR 192.731(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 9:246 (April 1983), amended LR 10:538 (July 1984), LR 30:1270 (June 2004).

§2935. Compressor Stations: Storage of Combustible Materials [49 CFR 192.735]

A. Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building. [49 CFR 192.735(a)]

B. Aboveground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference, see §507). [49 CFR 192.735(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 9:246 (April 1983), amended LR 10:538 (July 1984), LR 30:1270 (June 2004), LR 44:1042 (June 2018).

§2936. Compressor Stations: Gas Detection [49 CFR 192.736]

A. Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is: [49 CFR 192.736(a)]

1. constructed so that at least 50 percent of its upright side area is permanently open; or [49 CFR 192.736(a)(1)]

2. located in an unattended field compressor station of 1,000 horsepower (746 kW) or less. [49 CFR 192.736(a)(2)]

B. Except when shutdown of the system is necessary for maintenance under Subsection C of this Section, each gas detection and alarm system required by this Section must: [49 CFR 192.736(b)]

1. continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and [49 CFR 192.736(b)(1)]

2. if that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger. [49 CFR 192.736(b)(2)]

C. Each gas detection and alarm system required by this Section must be maintained to function properly. The maintenance must include performance tests. [49 CFR 192.736(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 21:824 (August 1995), amended LR 27:1549 (September 2001), LR 30:1270 (June 2004).

§2939. Pressure Limiting and Regulating Stations: Inspection and Testing [49 CFR 192.739]

A. Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is [49 CFR 192.739(a)]:

1. in good mechanical condition [49 CFR 192.739(a)(1)];

2. adequate from the standpoint of capacity and reliability of operation for the service in which it is employed [49 CFR 192.739(a)(2)];

3. except as provided in Subsection B of this Section, set to control or relieve at the correct pressure consistent with the pressure limits of §1161.A and [49 CFR 192.739(a)(3)];

4. properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation [49 CFR 192.739(a)(4)].

B. For steel pipelines whose MAOP is determined under §2719(C), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows: [49 CFR 192.739(b)]

If the MAOP produces a hoop stress that is:	then the pressure limit is:
Greater than 72 percent of SMYS	MAOP plus 4 percent.
Unknown as a percentage of SMYS	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

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 10:538 (July 1984), LR 30:1270 (June 2004), LR 31:685 (March 2005), LR 33:482 (March 2007).

§2940. Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Production, Gathering, or Transmission Pipelines [49 CFR 192.740]

A. This Section applies, except as provided in Subsection C of this Section, to any service line directly connected to a transmission pipeline or regulated gathering pipeline as determined in §508 that is not operated as part of a distribution system. [49 CFR 192.740(a)]

B. Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every three calendar years, not exceeding 39 months, to determine that it is: [49 CFR 192.740(b)]

1. a controller's authority and responsibility to make decisions and take actions during normal operations; [49 CFR 192.740(b)(1)]

2. adequate from the standpoint of capacity and reliability of operation for the service in which it is employed; [49 CFR 192.740(b)(2)]

3. set to control or relieve at the correct pressure consistent with the pressure limits of § 192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and [49 CFR 192.740(b)(3)]

4. properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation. [49 CFR 192.740(b)(4)]

C. This Section does not apply to equipment installed on: [49 CFR 192.740(c)]

1. a service line that only serves engines that power irrigation pumps; [49 CFR 192.740(c)(1)]

2. a service line included in a distribution integrity management plan meeting the requirements of Chapter 35 of this Subpart; or [49 CFR 192.740(c)(2)]

3. a service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in §508 of this Subpart. [49 CFR 192.740(c)(3)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 44:1042 (June 2018), LR 46:1597 (November 2020), LR 47:1146 (August 2021), repromulgated LR.47:1332 (September 2021).

§2941. Pressure Limiting and Regulating Stations: Telemetering or Recording Gages, [49 CFR 192.741]

A. Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gages to indicate the gas pressure in the district. [49 CFR 192.741(a)]

B. On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gages in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions. [49 CFR 192.741(b)]

C. If there are indications of abnormally high- or low-pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions. [49 CFR 192.741(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 9:246 (April 1983), amended LR 10:538 (July 1984), LR 30:1270 (June 2004).

§2943. Pressure Limiting and Regulating Stations: Capacity of Relief Devices [49 CFR 192.743]

A. Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §2939.B, the capacity must be consistent with the pressure limits of §1161.A. This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations [49 CFR 192.743(a)].

B. If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient. [49 CFR 192.743(b)]

C. If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by Subsection A of this Section. [49 CFR 192.743(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 9:246 (April 1983), amended LR 10:538 (July 1984), LR 30:1271 (June 2004), LR 31:685 (March 2005), LR 33:482 (March 2007).

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

A. Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year. [49 CFR 192.745(a)]

B. Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve. [49 CFR 192.745(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 9:246 (April 1983), amended LR 10:539 (July 1984), LR 30:1271 (June 2004).

§2947. Valve Maintenance: Distribution Systems [49 CFR 192.747]

A. Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year. [49 CFR 192.747(a)]

B. Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve. [49 CFR 192.747(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 9:246 (April 1983), amended LR 10:539 (July 1984), LR 30:1271 (June 2004).

§2949. Vault Maintenance [49 CFR 192.749]

A. Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated. [49 CFR 192.749(a)]

B. If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired. [49 CFR 192.749(b)]

C. The ventilating equipment must also be inspected to determine that it is functioning properly. [49 CFR 192.749(c)]

D. Each vault cover must be inspected to assure that it does not present a hazard to public safety. [49 CFR 192.749(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 9:246 (April 1983), amended LR 10:539 (July 1984), LR 27:1549 (September 2001), LR 30:1271 (June 2004).

§2950. Launcher and Receiver Safety [49 CFR 192.750]

A. Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g. inspection tools, scrapers, or spheres), if pressure has not been relieved. [49 CFR 192.750]

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 46:1597 (November 2020).

§2951. Prevention of Accidental Ignition [49 CFR 192.751]

A. Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following: [49 CFR 192.751]

1. when a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided; [49 CFR 192.751(a)]

2. gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work; [49 CFR 192.751(b)]

3. post warning signs, where appropriate. [49 CFR 192.751(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 9:247 (April 1983), amended LR 10:539 (July 1984), LR 30:1271 (June 2004).

§2953. Caulked Bell and Spigot Joints [49 CFR 192.753]

A. Each cast-iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172 kPa) gage must be sealed with: [49 CFR 192.753(a)]

1. a mechanical leak clamp; or [49 CFR 192.753(a)(1)]

2. a material or device which: [49 CFR 192.753(a)(2)]

a. does not reduce the flexibility of the joint; [49 CFR 192.753(a)(2)(i)]

b. permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and [49 CFR 192.753(a)(2)(ii)]

c. seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §703.A.1 and A.2 and §1103. [49 CFR 192.753(a)(2)(iii)]

B. Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psi (172 kPa) gage or less and is exposed for any reason, must be sealed by a means other than caulking. [49 CFR 192.753(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 9:247 (April 1983), amended LR 10:539 (July 1984), LR 27:1549 (September 2001), LR 30:1271 (June 2004).

§2955. Protecting Cast-Iron Pipelines [49 CFR 192.755]

A. When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed: [49 CFR 192.755]

1. that segment of the pipeline must be protected, as necessary, against damage during the disturbance by: [49 CFR 192.755(a)]

a. vibrations from heavy construction equipment, trains, trucks, buses, or blasting; [49 CFR 192.755(a)(1)]

b. impact forces by vehicles; [49 CFR 192.755(a)(2)]

c. earth movement; [49 CFR 192.755(a)(3)]

d. apparent future excavations near the pipeline; or [49 CFR 192.755(a)(4)]

e. other foreseeable outside forces which may subject that segment of the pipeline to bending stress; [49 CFR 192.755(a)(5)]

2. as soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of §§1717.A, 1719, and 1911.B through D. [49 CFR 192.755(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 9:247 (April 1983), amended LR 10:539 (July 1984), LR 30:1272 (June 2004).

§2956. Joining Plastic Pipe by Heat Fusion; Equipment Maintenance and Calibration. [49 CFR 192.756]

A. Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints. [49 CFR 192.756]

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 46:1597 (November 2020).

Chapter 31. Operator Qualification [49 CFR Part 192 Subpart N]

§3101. Scope [49 CFR 192.801]

A. This Chapter prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility. [49 CFR 192.801(a)]

B. For the purpose of this Chapter, a covered task is an activity, identified by the operator, that: [49 CFR 192.801(b)]

1. is performed on a pipeline facility; [49 CFR 192.801(b)(1)]

2. is an operations or maintenance task; [49 CFR 192.801(b)(2)]

3. is performed as a requirement of this Part; and [49 CFR 192.801(b)(3)]

4. affects the operation or integrity of the pipeline. [49 CFR 192.801(b)(4)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 27:1550 (September 2001), amended LR 30:1272 (June 2004).

§3103. Definitions [49 CFR 192.803]

Abnormal Operating Condition—a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

1. indicate a condition exceeding design limits; or

2. result in a hazard(s) to persons, property, or the environment.

Evaluation—a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

1. written examination;

2. oral examination;

3. work performance history review;

4. observation during:

   a. performance on the job;

   b. on the job training; or

   c. simulations; or

5. other forms of assessment.

Qualified—that an individual has been evaluated and can:

1. perform assigned covered tasks; and

2. recognize and react to abnormal operating conditions.

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 27:1550 (September 2001), amended LR 30:1272 (June 2004).

§3105. Qualification Program [49 CFR 192.805]

A. Each operator shall have and follow a written qualification program. The program shall include provisions to: [49 CFR 192.805]

1. identify covered tasks; [49 CFR 192.805(a)]

2. ensure through evaluation that individuals performing covered tasks are qualified; [49 CFR 192.805(b)]

3. allow individuals that are not qualified pursuant to this Subpart to perform a covered task if directed and observed by an individual that is qualified; [49 CFR 192.805(c)]

4. evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Chapter 3 of this Part; [49 CFR 192.805(d)]

5. evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task; [49 CFR 192.805(e)]

6. communicate changes that affect covered tasks to individuals performing those covered tasks; [49 CFR 192.805(f)]

7. identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed [49 CFR 192.805(g)];

8. after December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities [49 CFR 192.805(h)]; and

9. After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if an operator significantly modifies the program after the administrator or state agency has verified that it complies with this Section. Notifications to PHMSA must be submitted in accordance with §518. [49 CFR 192.805(i)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 27:1550 (September 2001), amended LR 30:1272 (June 2004), LR 31:685 (March 2005), LR 33:482 (March 2007), LR 35:2811 (December 2009), LR 44:1042 (June 2018), LR 46:1597 (November 2020).

§3107. Recordkeeping [49 CFR 192.807]

A. Each operator shall maintain records that demonstrate compliance with this Subpart. [49 CFR 192.807]

1. Qualification records shall include: [49 CFR 192.807(a)]

a. identification of qualified individual(s); [49 CFR 192.807(a)(1)]

b. identification of the covered tasks the individual is qualified to perform; [49 CFR 192.807(a)(2)]

c. date(s) of current qualification; and [49 CFR 192.807(a)(3)]

d. qualification method(s). [49 CFR 192.807(a)(4]

2. Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years. [49 CFR 192.807(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, Pipeline Division, LR 27:1550 (September 2001), amended LR 30:1272 (June 2004).

§3109. General [49 CFR 192.809]

A. Operators must have a written qualification program by April 27, 2001. The program must be available for review by the administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency [49 CFR 192.809(a)].

B. Operators must complete the qualification of individuals performing covered tasks by October 28, 2002. [49 CFR 192.809(b)]

C. Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999. [49 CFR 192.809(c)]

D. After October 28, 2002, work performance history may not be used as a sole evaluation method. [49 CFR 192.809(d)]

E. After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation [49 CFR 192.809(e)].

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:501 et seq.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 27:1550 (September 2001), amended LR 30:1273 (June 2004), LR 33:482 (March 2007).

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

§3301. What Do the Regulations in this Chapter Cover? 49 CFR 192.901]

A. This Chapter prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this Part. For gas transmission pipelines constructed of plastic, only the requirements in §§3317, 3321, 3335 and 3337 apply. [49 CFR 192.901]

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 30:1273 (June 2004).

§3303. What Definitions Apply to this Chapter? [49 CFR 192.903]

A. The following definitions apply to this Chapter.

Assessment—the use of testing techniques as allowed in this Chapter to ascertain the condition of a covered pipeline segment.

Confirmatory Direct Assessment—an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered Segment or Covered Pipeline Segment—a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in §503.

Direct Assessment—an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

High Consequence Area—an area established by one of the methods described in Subparagraphs a or b as follows:

a. An *area* defined as:

i. a Class 3 location under §505; or

ii. a Class 4 location under §505; or

iii. any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

iv. any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

b. The area within a potential impact circle containing:

i. 20 or more buildings intended for human occupancy, unless the exception in Subparagraph d applies; or

ii. an identified site.

c. Where a potential impact circle is calculated under either method a. or b. to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy (see Figure E.I.A. in §5109 Appendix E).

d. If in identifying a high consequence area under Clause a.iii of this definition or Clause b.i of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to 20 x (660 feet) [or 200 meters]/ potential impact radius in feet [or meters]^2).

Identified Site—each of the following areas:

a. an outside area or open structure that is occupied by 20 or more persons on at least 50 days in any 12 month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility); or

b. a building that is occupied by 20 or more persons on at least five days a week for 10 weeks in any 12 month period. (The days and weeks need not be consecutive). Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks); or

c. a facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential Impact Circle—a circle of radius equal to the potential impact radius (PIR).

Potential Impact Radius (PIR)—the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69 * [square root of ($p*d^2$)], where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

NOTE: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use Section 3.2 of ASME/ANSI B31.8S incorporated by reference, see §507) to calculate the impact radius formula.

Remediation—a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

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 30:1273 (June 2004), amended LR 31:685 (March 2005), LR 33:483 (March 2007), LR 35:2811 (December 2009), LR 44:1042 (June 2018).

§3305. How Does an Operator Identify a High Consequence Area? [49 CFR 192.905]

A. General. To determine which segments of an operator's transmission pipeline system are covered by this Chapter, an operator must identify the high consequence areas. An operator must use Method a or b from the definition in §3303 to identify a *high consequence area*. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See §5109, Appendix E.I for guidance on identifying high consequence areas.) [49 CFR 192.905(a)]

B. Identified Sites. An operator must identify an identified site, for purposes of this Chapter, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials. If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites: [49 CFR 192.905(b)]

1. visible marking (e.g., a sign); or [49 CFR 192.905(b)(1)]

2. the site is licensed or registered by a federal, state, or local government agency; or [49 CFR 192.905(b)(2)]

3. the site is on a list (including a list on an internet web site) or map maintained by or available from a federal, state, or local government agency and available to the general public. [49 CFR 192.905(b)(3)]

C. Newly-Identified Areas. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §3303, the operator must complete the evaluation using Method (a) or (b). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified. [49 CFR 192.905(c)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1274 (June 2004).

§3307. What Must an Operator Do to Implement this Chapter? [49 CFR 192.907]

A. General. No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §3311 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program. [49 CFR 192.907(a)]

B. Implementation Standards. In carrying out this Chapter, an operator must follow the requirements of this Chapter and of ASME/ANSI B31.8S (incorporated by reference, see §507) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this Chapter and ASME/ANSI B31.8S, the requirements in this Chapter control [49 CFR 192.907(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, Pipeline Division, LR 30:1274 (June 2004), LR 33:483 (March 2007).

§3309. How Can an Operator Change Its Integrity Management Program? [49 CFR 192.909]

A. General. An operator must document any change to its program and the reasons for the change before implementing the change. [49 CFR 192.909(a)]

B. Notification. An operator must notify OPS, in accordance with §518, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide notification within 30 days after adopting this type of change into its program. [49 CFR 192.909(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, Pipeline Division, LR 30:1274 (June 2004), amended LR 31:686 (March 2005), LR 46:1598 (November 2020).

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

A. An operator's initial integrity management program begins with a framework (see §3307) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements: [(When indicated, refer to ASME/ANSI B31.8S (ibr, see §507) for more detailed information on the listed element.] [49 CFR 192.911]

1. an identification of all high consequence areas, in accordance with §3305; [49 CFR 192.911(a)]

2. a baseline assessment plan meeting the requirements of §§3319 and 3321; [49 CFR 192.911(b)]

3. an identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§3317) and to evaluate the merits of additional preventive and mitigative measures (§3335) for each covered segment; [49 CFR 192.911(c)]

4. a direct assessment plan, if applicable, meeting the requirements of §3323, and depending on the threat assessed, of §§3325, 3327, or 3329; [49 CFR 192.911(d)]

5. provisions meeting the requirements of §3333 for remediating conditions found during an integrity assessment; [49 CFR 192.911(e)]

6. a process for continual evaluation and assessment meeting the requirements of §3337; [49 CFR 192.911(f)]

7. if applicable, a plan for confirmatory direct assessment meeting the requirements of §3331; [49 CFR 192.911(g)].

8. provisions meeting the requirements of §3335 for adding preventive and mitigative measures to protect the high consequence area; [49 CFR 192.911(h)]

9. a performance plan as outlined in ASME/ANSI B31.8S, Section 9 that includes performance measures meeting the requirements of §3345; [49 CFR 192.911(i)]

10. record keeping provisions meeting the requirements of §3347; [49 CFR 192.911(j)]

11. a management of change process as outlined in ASME/ANSI B31.8S, Section 11; [49 CFR 192.911(k)]

12. a quality assurance process as outlined in ASME/ANSI B31.8S, Section 12; [49 CFR 192.911(l)]

13. a communication plan that includes the elements of ASME/ANSI B31.8S, Section 10, and that includes procedures for addressing safety concerns raised by: [49 CFR 192.911(m)]

a. OPS; and [49 CFR 192.911(m)(1)]

b. a state or local pipeline safety authority when a covered segment is located in a state where OPS has an interstate agent agreement; [49 CFR 192.911(m)(2)]

c. Office of Conservation—Pipeline Division for intrastate jurisdictional facilities;

14. procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to: [49 CFR 192.911(n)]

a. OPS; and [49 CFR 192.911(n)(1)]

b. a state or local pipeline safety authority when a covered segment is located in a state where OPS has an interstate agent agreement; [49 CFR 192.911(n)(2)]

c. Office of Conservation—Pipeline Division for intrastate jurisdictional facilities;

15. procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks; [49 CFR 192.911(o)]

16. a process for identification and assessment of newly-identified high consequence areas. (See §§3305 and 3321) [49 CFR 192.911(p)]

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§3313. When May an Operator Deviate Its Program from Certain Requirements of this Chapter? [49 CFR 192.913]

A. General. ASME/ANSI B31.8S (ibr, see §507) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in Subsection B of this Section may deviate from certain requirements in this Chapter, as provided in Subsection C of this Section. [49 CFR 192.913(a)]

B. Exceptional Performance. An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions. [49 CFR 192.913(b)]

1. To deviate from any of the requirements set forth in Subsection C of this Section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements: [49 CFR 192.913(b)(1)]

a. a comprehensive process for risk analysis; [49 CFR 192.913(b)(1)(i)]

b. all risk factor data used to support the program; [49 CFR 192.913(b)(1)(ii)]

c. a comprehensive data integration process; [49 CFR 192.913(b)(1)(iii)]

d. a procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this Chapter; [49 CFR 192.913(b)(1)(iv)]

e. a procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program; [49 CFR 192.913(b)(1)(v)]

f. a performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments; [49 CFR 192.913(b)(1)(vi)]

g. semi-annual performance measures beyond those required in §3345 that are part of the operator's performance plan [see §3311.9]. An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §3351 [49 CFR 192.913(b)(1)(vii)]; and

h. an analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments. [49 CFR 192.913(b)(1)(viii)]

2. In addition to the requirements for the performance-based plan, an operator must: [49 CFR 192.913(b)(2)]

a. have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment; [49 CFR 192.913(b)(2)(i)]

b. remediate all anomalies identified in the more recent assessment according to the requirements in §3333, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment. [49 CFR 192.913(b)(2)(ii)]

C. Deviation. Once an operator has demonstrated that it has satisfied the requirements of Subsection B of this Section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this Chapter only in the following instances. [49 CFR 192.913(c)]

1. The time frame for reassessment as provided in §3339 except that reassessment by some method allowed under this Chapter (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years. [49 CFR 192.913(c)(1)]

2. The time frame for remediation as provided in §3333 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment. [49 CFR 192.913(c)(2)]

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§3315. What Knowledge and Training Must Personnel Have to Carry Out an Integrity Management Program? [49 CFR 192.915]

A. Supervisory Personnel. The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible. [49 CFR 192.915(a)]

B. Persons Who Carry Out Assessments and Evaluate Assessment Results. The integrity management program must provide criteria for the qualification of any person: [49 CFR 192.915(b)]

1. who conducts an integrity assessment allowed under this Chapter; or [49 CFR 192.915(b)(1)]

2. who reviews and analyzes the results from an integrity assessment and evaluation; or [49 CFR 192.915(b)(2)]

3. who makes decisions on actions to be taken based on these assessments. [49 CFR 192.915(b)(3)]

C. Persons Responsible for Preventive and Mitigative Measures. The integrity management program must provide criteria for the qualification of any person: [49 CFR 192.915(c)]

1. who implements preventive and mitigative measures to carry out this Chapter, including the marking and locating of buried structures; or [49 CFR 192.915(c)(1)]

2. who directly supervises excavation work carried out in conjunction with an integrity assessment. [49 CFR 192.915(c)(2)]

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

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

1. time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking; [49 CFR 192.917(a)(1)]

2. static or resident threats, such as fabrication or construction defects; [49 CFR 192.917(a)(2)]

3. time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and [49 CFR 192.917(a)(3)]

4. human error. [49 CFR 192.917(a)(4)]

B. Data Gathering and Integration. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, Section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline [49 CFR 192.917(b)].

C. Risk Assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, Section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§3319, 3321, 3337), and to determine what additional preventive and mitigative measures are needed (§3335) for the covered segment. [49 CFR 192.917(c)]

D. Plastic Transmission Pipeline. An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in Sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe. [49 CFR 192.917(d)]

E. Actions to Address Particular Threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat. [49 CFR 192.917(e)]

1. Third Party Damage. An operator must utilize the data integration required in Subsection B of this Section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §3335 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §3321, or a reassessment under §3337, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of

third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration. [49 CFR 192.917(e)(1)]

2. Cyclic Fatigue. An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The analysis must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the analysis together with the criteria used to determine the significance of the threat(s) to the covered segment to prioritize the integrity baseline assessment or reassessment. Failure stress pressure and crack growth analysis of cracks and crack-like defects must be conducted in accordance with §2912. An operator must monitor operating pressure cycles and periodically, but at least every seven calendar years, with intervals not to exceed 90 months, determine if the cyclic fatigue analysis remains valid or if the cyclic fatigue analysis must be revised based on changes to operating pressure cycles or other loading conditions. [49 CFR 192.917(e)(2)]

3. Manufacturing and construction defects. An operator must analyze the covered segment to determine and account for the risk of failure from manufacturing and construction defects (including seam defects) in the covered segment. The analysis must account for the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of Chapter 23 of at least 1.25 times MAOP, and the covered segment has not experienced a reportable incident attributed to a manufacturing or construction defect since the date of the most recent Chapter 23 pressure test. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment: [49 CFR 192.917(e)(3)]

a. the pipeline segment has experienced a reportable incident, as defined in §303, since its most recent successful Chapter 23 pressure test, due to an original manufacturing-related defect, or a construction-, installation-, or fabrication-related defect; [49 CFR 192.917(e)(3)(i)]

b. MAOP increases; or [49 CFR 192.917(e)(3)(ii)]

c. the stresses leading to cyclic fatigue increase. [49 CFR 192.917(e)(3)(iii)]

4. Electric Resistance Welded (ERW) Pipe. If a covered pipeline segment contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0 as defined in §913, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure (including seam cracking and selective seam weld corrosion), or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years (including abnormal operation as defined in §2705.C, or MAOP has been increased, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis to estimate the remaining life of the pipe in accordance with § 2912. [49 CFR 192.917(e)(4)]

5. Corrosion. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §3331), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under Subpart 3 for testing and repair. [49 CFR 192.917(e)(5)]

6. Cracks. If an operator identifies any crack or crack-like defect (e.g., stress corrosion cracking or other environmentally assisted cracking, seam defects, selective seam weld corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar characteristics associated with the crack or crack-like defect. Similar characteristics may include operating and maintenance histories, material properties, and environmental characteristics. An operator must establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments that is consistent with the operator's established operating and maintenance procedures under this part for testing and repair. [49 CFR 192.917(e)(6)]

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§3319. What Must Be in the Baseline Assessment Plan [49 CFR 192.919]

A. An operator must include each of the following elements in its written baseline assessment plan: [49 CFR 192.919]

1. identification of the potential threats to each covered pipeline segment and the information supporting the threat identification (see §3317); [49 CFR 192.919(a)]

2. the methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment (see §3317). More than one method may be required to address all the threats to the covered pipeline segment; [49 CFR 192.919(b)]

3. a schedule for completing the integrity assessment of all covered segments, including, risk factors considered in establishing the assessment schedule; [49 CFR 192.919(c)]

4. if applicable, a direct assessment plan that meets the requirements of §3323, and depending on the threat to be addressed, of §§3325, 3327, or 3329; and [49 CFR 192.919(d)]

5. a procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks. [49 CFR 192.919(e)]

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§3321. How Is the Baseline Assessment to be Conducted [49 CFR 192.921]

A. Assessment Methods. An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See § 3317): [49 CFR 192.921(a)]

1. internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with §2145. In addition, an operator must analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies; [49 CFR 192.921(a)(1)];

2. pressure test conducted in accordance with Chapter 23 of this Subpart. The use of Chapter 23 pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, see §507) to justify an extended reassessment interval in accordance with § 3339. [49 CFR 192.921(a)(2)].

3. spike hydrostatic pressure test conducted in accordance with §2306. The use of spike hydrostatic pressure testing is appropriate for time- dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects; [49 CFR 192.921(a)(3)]

4. excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI); [49 CFR 192.921(a)(4)]

5. guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss; [49 CFR 192.921(a)(5)]

6. direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in §3323 and with the applicable requirements specified in §§3325, 3327 and 3329; or [49 CFR 192.921(a)(6)]

7. other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with §518. [49 CFR 192.921(a)(7)]

B. Prioritizing Segments. An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §3317. [49 CFR 192.921(b)]

C. Assessment for Particular Threats. In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §3317.E to address particular threats that it has identified. [49 CFR 192.921(c)]

D. Time Period. An operator must prioritize all the covered segments for assessment in accordance with §3317.C and Subsection B of this Section. An operator must assess at least 50 percent of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012. [49 CFR 192.921(d)]

E. Prior Assessment. An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this Chapter and subsequent remedial actions to address the conditions listed in §3333 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §3337 and §3339. [49 CFR 192.921(e)]

F. Newly-Identified Areas. When an operator identifies a new high consequence area (see §3305), an operator must complete the baseline assessment of the line pipe in the newly-identified high consequence area within 10 years from the date the area is identified. [49 CFR 192.921(f)]

G. Newly Installed Pipe. An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this Subpart within 10 years from the date the pipe is installed. An operator may conduct a pressure test in accordance with Paragraph A.2 of this Section, to satisfy the requirement for a baseline assessment [49 CFR 192.921(g)].

H. Plastic Transmission Pipeline. If the threat analysis required in §3317.D on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this Section and of §3317. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment. [49 CFR 192.921(h)]

I. Baseline assessments for pipeline segments with a reconfirmed MAOP. An integrity assessment conducted in accordance with the requirements of § 2724.C may be used as a baseline assessment under this Section. [49 CFR 192.921(i)]

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

A. General. An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this Chapter. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC). [49 CFR 192.923(a)]

B. Primary Method. An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in: [49 CFR 192.923(b)]

1. §3325 and ASME/ANSI B31.8S (incorporated by reference, see §507), section 6.4, and NACE SP0502 (incorporated by reference, see §507) if addressing external corrosion (EC). [49 CFR 192.923(b)(1)]

2. §3327 and ASME/ANSI B31.8S (incorporated by reference, see §507), section 6.4, appendix B2, if addressing internal corrosion (IC). [49 CFR 192.923(b)(2)]

3. §3329 and ASME/ANSI B31.8S (incorporated by reference, see §5070, appendix A3, if addressing stress corrosion cracking (SCC). [49 CFR 192.923(b)(3)]

C. Supplemental Method. An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §3331. [49 CFR 192.923(c)]

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§3325. What Are the Requirements for Using External Corrosion Direct Assessment (ECDA)? [49 CFR 192.925]

A. Definition. ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline. [49 CFR 192.925(a)]

B. General Requirements. An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this Section, in ASME/ANSI B31.8S (incorporated by reference, see §507), section 6.4, and in NACE SP0502 (incorporated by reference, see §507). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§3317.B) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §3317.E.1 [49 CFR 192.925(b)].

1. Pre-assessment. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 3, the plan's procedures for pre-assessment must include: [49 CFR 192.925(b)(1)]

a. provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and [49 CFR 192.925(b)(1)(i)]

b. the basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in appendix A of NACE SP0502, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method. [49 CFR 192.925(b)(1)(ii)]

2. Indirect Inspection. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 4, the plan's procedures for indirect inspection of the ECDA regions must include: [49 CFR 192.925(b)(2)]

a. provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; [49 CFR 192.925(b)(2)(i)]

b. criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected; [49 CFR 192.925(b)(2)(ii)]

c. criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and [49 CFR 192.925(b)(2)(iii)]

d. criteria for scheduling excavation of indications for each urgency level. [49 CFR 192.925(b)(2)(iv)]

3. Direct Examination. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 5, the plan's procedures for direct examination of indications from the indirect examination must include: [49 CFR 192.925(b)(3)]

a. provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; [49 CFR 192.925(b)(3)(i)]

b. criteria for deciding what action should be taken if either: [49 CFR 192.925(b)(3)(ii)]

i. corrosion defects are discovered that exceed allowable limits (section 5.5.2.2 of NACE SP0502; or [49 CFR 192.925(b)(3)(ii)(A)]

ii. root cause analysis reveals conditions for which ECDA is not suitable (section 5.6.2 of NACE SP0502; [49 CFR 192.925(b)(3)(ii)(B)]

c. criteria and notification procedures for any changes in the ECDA plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and [49 CFR 192.925(b)(3)(iii)]

d. criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502. [49 CFR 192.925(b)(3)(iv)]

4. Post Assessment and Continuing Evaluation. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include: [49 CFR 192.925(b)(4)]

a. measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and [49 CFR 192.925(b)(4)(i)]

b. criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §3339 (see appendix D of NACE SP0502. [49 CFR 192.925(b)(4)(ii)]

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

A. Definition. Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas. [49 CFR 192.927(a)]

B. General Requirements. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this Section and in ASME/ANSI B31.8S (incorporated by reference, see §507), Section 6.4 and Appendix B2. The ICDA process described in this Section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with §3321.A.4 or §3337.C.4 [49 CFR 192.927(b).]

C. The ICDA Plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring. [49 CFR 192.927(c)]

1. Preassessment. In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to: [49 CFR 192.927(c)(1)]

a. all data elements listed in Appendix A2 of ASME/ANSI B31.8S; [49 CFR 192.927(c)(1)(i)]

b. information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur (see Subsection A of this Section). This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline; [49 CFR 192.927(c)(1)(ii)]

c. operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and [49 CFR 192.927(c)(1)(iii)]

d. information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes. [49 CFR 192.927(c)(1)(iv)]

2. ICDA Region Identification. An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," (incorporated by reference, see §507). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas [49 CFR 192.927(c)(2)].

3. Identification of Locations for Excavation and Direct Examination. An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must: [49 CFR 192.927(c)(3)]

a. evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §3333; [49 CFR 192.927(c)(3)(i)]

b. as part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this Subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and [49 CFR 192.927(c)(3)(ii)]

c. evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §3333. [49 CFR 192.927(c)(3)(iii)]

4. Post-Assessment Evaluation and Monitoring. An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes: [49 CFR 192.927(c)(4)]

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

b. continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this Chapter, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §3333: [49 CFR 192.927(c)(4)(ii)]

i. conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or [49 CFR 192.927(c)(4)(ii)(A)]

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

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

a. criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process; [49 CFR 192.927(c)(5)(i)]

b. provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and [49 CFR 192.927(c)(5)(ii)]

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

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

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

B. General Requirements. An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for: [49 CFR 192.929(b)]

1. Data Gathering and Integration. An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (incorporated by reference, see §507), Appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, Appendix A3 [49 CFR 192.929(b)(1)];

2. Assessment Method. The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4. [49 CFR 192.929(b)(2)]

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§3331. How May Confirmatory Direct Assessment (CDA) Be Used? [49 CFR 192.931]

A. An operator using the confirmatory direct assessment (CDA) method as allowed in §3337 must have a plan that meets the requirements of this Section and of §3325 (ECDA) and §3327 (ICDA). [49 CFR 192.931]

1. Threats. An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion. [49 CFR 192.931(a)]

2. External Corrosion Plan. An operator's CDA plan for identifying external corrosion must comply with §3325 with the following exceptions. [49 CFR 192.931(b)]

a. The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application. [49 CFR 192.931(b)(1)]

b. The procedures for direct examination and remediation must provide that: [49 CFR 192.931(b)(2)]

(i) all immediate action indications must be excavated for each ECDA region; and [49 CFR 192.931(b)(2)(i)]

(ii) at least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region. [49 CFR 192.931(b)(2)(ii)]

3. Internal Corrosion Plan. An operator's CDA plan for identifying internal corrosion must comply with §3327 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region. [49 CFR 192.931(c)]

4. Defects Requiring Near-Term Remediation. If an assessment carried out under Paragraphs 2 or 3 of this Section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502 (incorporated by reference, see §507), sections 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with §3333 until the operator has completed reassessment using one of the assessment techniques allowed in §3337. [49 CFR 192.931(d)]

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

A. General Requirements. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. [49 CFR 192.933(a)]

1. Temporary Pressure Reduction. If an operator is unable to respond within the time limits for certain conditions specified in this Section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this Section using ASME/ANSI B31G (incorporated by reference, see §507); R - STRENG (incorporated by reference, see §507); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with §518 if it cannot meet the schedule for evaluation and remediation required under Subsection C of this Section and cannot provide safety through a temporary reduction in operating pressure or through another action. [49 CFR 192.933(a)(1)]

2. Long-Term Pressure Reduction. When a pressure reduction exceeds 365 days, an operator must notify PHMSA under §518 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. [49 CFR 192.933(a)(2)]

B. Discovery of Condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under Paragraphs D.1 through D.3 of this Section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable [49 CFR 192.933(b)].

C. Schedule for Evaluation and Remediation. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in Subsection D of this Section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §507), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. [49 CFR 192.933(c)]

D. Special Requirements for Scheduling Remediation. [49 CFR 192.933(d)]

1. Immediate Repair Conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with Subsection A of this Section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions: [49 CFR 192.933(d)(1)]

a. a calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, see §507), PRCI PR-3-0805 (R-STRENG) (incorporated by reference, see §507) or an alternative equivalent method of remaining strength calculation. [49 CFR 192.933(d)(1)(i)];

b. a dent that has any indication of metal loss, cracking or a stress riser; [49 CFR 192.933(d)(1)(ii)]

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

2. One-Year Conditions. Except for conditions listed in Paragraphs D.1 and D.3 of this Section, an operator must remediate any of the following within one year of discovery of the condition: [49 CFR 192.933(d)(2)]

a. a smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12); [49 CFR 192.933(d)(2)(i)]

b. a dent with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld. [49 CFR 192.933(d)(2)(ii)]

3. Monitored Conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation: [49 CFR 192.933(d)(3)]

a. a dent with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe); [49 CFR 192.933(d)(3)(i)]

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

c. a dent with a depth greater than 2 percent of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties. [49 CFR 192.933(d)(3)(iii)]

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

A. General Requirements. An operator must take additional measures beyond those already required by this Subpart to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment (see §3317). An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, see §507), Section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing automatic shut-off valves or remote control valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs [49 CFR 192.935(a)].

B. Third Party Damage and Outside Force Damage [49 CFR 192.935(b)]

1. Third Party Damage. An operator must enhance its damage prevention program, as required under §2714 of this Subpart, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum [49 CFR 192.935(b)(1)]:

a. using qualified personnel (see §3315) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work; [49 CFR 192.935(b)(1)(i)]

b. collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Subparts 1 and 2; [49 CFR 192.935(b)(1)(ii)]

c. participating in one-call systems in locations where covered segments are present; [49 CFR 192.935(b)(1)(iii)]

d. monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, see §507). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §3333 any indication of coating holidays or discontinuity warranting direct examination [49 CFR 192.935(b)(1)(iv)].

2. Outside Force Damage. If an operator determines that outside force (e.g., earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include increasing the frequency of aerial, foot or other methods of patrols; adding external protection; reducing external stress; relocating the line; or inline inspections with geospatial and deformation tools. [49 CFR 192.935(b)(2)]

C. 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. Pipelines Operating below 30 percent SMYS. An operator of a transmission pipeline operating below 30 percent SMYS located in a high consequence area must follow the requirements in Paragraphs D.1 and D.2 of this Section. An operator of a transmission pipeline operating below 30 percent SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in Paragraphs D.1, D.2 and D.3 of this Section [49 CFR 192.935(d)].

1. apply the requirements in Subparagraphs B.1.a and B.1.c of this Section to the pipeline; and [49 CFR 192.935(d)(1)]

2. either monitor excavations near the pipeline, or conduct patrols as required by §2905 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred; [49 CFR 192.935(d)(2)]

3. perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). [49 CFR 192.935(d)(3)]

E. Plastic Transmission Pipeline. An operator of a plastic transmission pipeline must apply the requirements in Subparagraphs B.1.a, B.1.c and B.1.d of this Section to the covered segments of the pipeline. [49 CFR 192.935(e)]

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§3337. What Is a Continual Process of Evaluation and Assessment to Maintain a Pipeline's Integrity? [49 CFR 192.937]

A. General. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §3339 and periodically evaluate the integrity of each covered pipeline segment as provided in Subsection B of this Section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §3321.E by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §3321.D by no later than seven years after the baseline assessment of that covered segment unless the evaluation under Subsection B of this Section indicates earlier reassessment. [49 CFR 192.937(a)]

B. Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §3317. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in §3317.D. For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§3317), and decisions about remediation (§3333) and additional preventive and mitigative actions (§3335). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats [49 CFR 192.937(b)].

C. Assessment Methods. In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment (see § 3317). [49 CFR 192.937(c)]:

1. internal inspection tools. When performing an assessment using an in- line inspection tool, an operator must comply with the following requirements: [49 CFR 192.937(c)(1)]

a. perform the in-line inspection in accordance with §2145; [49 CFR 192.937(c)(1)(i)]

b. select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (e.g. dents, gouges and grooves), material cracking and crack-like defects (e.g. stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible; and [49 CFR 192.937(c)(1)(ii)]

c. analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies; [49 CFR 192.937(c)(1)(iii)]

2. pressure test conducted in accordance with Chapter 23 of this Subpart. The use of pressure testing is appropriate for threats such as: Internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, see §507) to justify an extended reassessment interval in accordance with § 3339; [49 CFR 192.937(c)(2)]

3. spike hydrostatic pressure test in accordance with §2306. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as: Stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects; [49 CFR 192.937(c)(3)]

4. excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, or magnetic particle inspection (MPI); [49 CFR 192.937(c)(4)]

5. guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss; [49 CFR 192.937(c)(5)].

6. direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in §3323 and with the applicable requirements specified in §§3325, 3327, and 3329; [49 CFR 192.937(c)(6)].

7. other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with §518; or [49 CFR 192.937(c)(7]

8. confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with §3331. [49 CFR 192.937(c)(8)].

D. MAOP reconfirmation assessments. An integrity assessment conducted in accordance with the requirements of §2724.C may be used as a reassessment under this Section (see §3317). [49 CFR 192.937(d)]

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§3339. What Are the Required Reassessment Intervals? [49 CFR 192.939]

A. An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments. [49 CFR 192.939]

1. Pipelines operating at or above 30 percent SMYS. An operator must establish a reassessment interval for each covered segment operating at or above 30 percent SMYS in accordance with the requirements of this Section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the seven-calendar- year reassessment interval if the operator submits written notice to OPS, in accordance with §518, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than seven calendar years, the operator must, within the seven-calendar-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §3331. The table that follows this Section sets forth the maximum allowed reassessment intervals. [49 CFR 192.939(a)]

a. Pressure Test or Internal Inspection or Other Equivalent Technology. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by: [49 CFR 192.939(a)(1)]

i. basing the interval on the identified threats for the covered segment (see §3317) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §3317; or [49 CFR 192.939(a)(1)(i)]

ii. using the intervals specified for different stress levels of pipeline (operating at or above 30 percent SMYS) listed in ASME B31.8S (incorporated by reference, see §507), Section 5, Table 3. [49 CFR 192.939(a)(1)(ii)]

b. External Corrosion Direct Assessment. An operator that uses ECDA that meets the requirements of this Chapter must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, see §507) [49 CFR 192.939(a)(2)].

c. Internal Corrosion or SCC Direct Assessment. An operator that uses ICDA or SCCDA in accordance with the requirements of this Chapter must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, Section 5, Table 3: [49 CFR 192.939(a)(3)]

i. determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions; [49 CFR 192.939(a)(3)(i)]

ii. use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and [49 CFR 192.939(a)(3)(ii)]

iii. estimate the reassessment interval as half the time required for the largest defect to grow to a critical size. [49 CFR 192.939(a)(3)(iii)]

2. Pipelines operating below 30 percent SMYS. An operator must establish a reassessment interval for each covered segment operating below 30 percent SMYS in accordance with the requirements of this Section. The maximum reassessment interval by an allowable reassessment method is seven calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS in accordance with §518. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following: [49 CFR 192.939(b)]

a. reassessment by pressure test, internal inspection or other equivalent technology following the requirements in Paragraph A.1 of this Section except that the stress level referenced in Subparagraph A.1.b of this Section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with §3331, or a low stress reassessment in accordance with §3341; [49 CFR 192.939(b)(1)]

b. reassessment by ECDA following the requirements in Subparagraph 1.b of this Section; [49 CFR 192.939(b)(2)]

c. reassessment by ICDA or SCCDA following the requirements in Subparagraph 1.c of this Section; [49 CFR 192.939(b)(3)]

d. reassessment by confirmatory direct assessment at 7-year intervals in accordance with §3331, with reassessment by one of the methods listed in Subparagraphs A.2.a-c of this Section by year 20 of the interval; [49 CFR 192.939(b)(4)]

e. reassessment by the low stress assessment method at 7-year intervals in accordance with §3341 with reassessment by one of the methods listed in Paragraphs B.1 through B.3 of this Section by year 20 of the interval [49 CFR 192.939(b)(5)].

f. the following table sets forth the maximum reassessment intervals. Also refer to §5109, Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30 percent SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment [49 CFR 192.939(b)(6)].

Maximum Reassessment Interval			
Assessment Method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years (*)	15 years (*)	20 years (**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low stress reassessment	not applicable	not applicable	7 years + ongoing actions specified in §3341.

(*)A confirmatory direct assessment as described in §3331 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**)A low stress reassessment or confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

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 30:1283 (June 2004), amended LR 31:688 (March 2005), LR 33:486 (March 2007), LR 38:122 (January 2012), LR 44:1044 (June 2018), LR 46:1601 (November 2020).

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

A. General. An operator of a transmission line that operates below 30 percent SMYS may use the following method to reassess a covered segment in accordance with §3339. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§3319 and 3321. [49 CFR 192.941(a)]

B. External Corrosion. An operator must take one of the following actions to address external corrosion on the low stress covered segment. [49 CFR 192.941(b)]

1. Cathodically Protected Pipe. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (i.e., indirect examination tool/method) at least every seven years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. [49 CFR 192.941(b)(1)]

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

a. conduct leakage surveys as required by §2906 at 4-month intervals; and [49 CFR 192.941(b)(2)(i)]

b. every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. [49 CFR 192.941(b)(2)(ii)]

C. Internal Corrosion. To address the threat of internal corrosion on a covered segment, an operator must: [49 CFR 192.941(c)]

1. conduct a gas analysis for corrosive agents at least once each calendar year; [49 CFR 192.941(c)(1)]

2. conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and [49 CFR 192.941(c)(2)]

3. at least every seven years, integrate data from the analysis and testing required by Paragraphs C.1. and 2 with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions. [49 CFR 192.941(c)(3)]

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

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

§3343. When Can an Operator Deviate from These Reassessment Intervals? [49 CFR 192.943]

A. Waiver from Reassessment Interval in Limited Situations. In the following limited instances, OPS may allow a waiver from a reassessment interval required by §3339 if OPS finds a waiver would not be inconsistent with pipeline safety. [49 CFR 192.943(a)]

1. Lack of Internal Inspection Tools. An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment. [49 CFR 192.943(a)(1)]

2. Maintain Product Supply. An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval. [49 CFR 192.943(a)(2)]

B. How to Apply. If one of the conditions specified in Paragraph A.1 or 2 of this Section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known. [49 CFR 192.943(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, Pipeline Division, LR 30:1285 (June 2004), amended LR 31:689 (March 2005).

§3345. What Methods Must an Operator Use to Measure Program Effectiveness? [49 CFR 192.945]

A. General. An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, see §507 of this Subpart), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by §317 of this Part. [49 CFR 192.945(a)].

B. External Corrosion Direct Assessment. In addition to the general requirements for performance measures in Subsection A of this Section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §3325. [49 CFR 192.945 (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, Pipeline Division, LR 30:1285 (June 2004), amended LR 31:689 (March 2005), LR 33:487 (March 2007), amended LR 31:689 (March 2005), LR 33:487 (March 2007), LR 38:122 (January 2012).

§3347. What Records Must an Operator Keep? [49 CFR 192.947]

A. An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this Chapter. At minimum, an operator must maintain the following records for review during an inspection: [49 CFR 192.947]

1. a written integrity management program in accordance with §3307; [49 CFR 192.947(a)]

2. documents supporting the threat identification and risk assessment in accordance with §3317; [49 CFR 192.947(b)]

3. a written baseline assessment plan in accordance with §3319; [49 CFR 192.947(c)]

4. documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements; [49 CFR 192.947(d)]

5. documents that demonstrate personnel have the required training, including a description of the training program, in accordance with §3315; [49 CFR 192.947(e)]

6. schedule required by §3333 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule; [49 CFR 192.947(f)]

7. documents to carry out the requirements in §3323 through §3329 for a direct assessment plan; [49 CFR 192.947(g)]

8. documents to carry out the requirements in §3331 for confirmatory direct assessment; [49 CFR 192.947(h)]

9. verification that an operator has provided any documentation or notification required by this Chapter to be provided to OPS, and when applicable, a state authority with which OPS has an interstate agent agreement, and a state or local pipeline safety authority that regulates a covered pipeline segment within that state. [49 CFR 192.947(i)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1285 (June 2004).

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

A. An operator must file any report required by this Chapter electronically to the Pipeline and Hazardous Materials Safety Administration in accordance with § 307 of this Part. [49 CFR 192.951]

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

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

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

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

§3501. What definitions apply to this chapter? [49 CFR 192.1001]

A. The following definitions apply to this Subpart. [49 CFR 192.1001]

Excavation Damage—any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

Hazardous Leak—a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous.

Integrity Management Plan or *IM Plan*—a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this chapter.

Integrity Management Program or *IM Program*—an overall approach by an operator to ensure the integrity of its gas distribution system.

Mechanical Fitting—a mechanical device used to connect sections of pipe. The term "Mechanical fitting" applies only to:

a. stab type fittings;

b. nut follower type fittings;

c. bolted type fittings; or

d. other compression type fittings.

Small LPG Operator—an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

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 38:122 (January 2012).

§3503. What do the Regulations in this Chapter Cover? [49 CFR 192.1003]

A. General. Unless exempted in Subsection B of this Section this Chapter prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this Subpart, including liquefied petroleum gas systems. A gas distribution operator must follow the requirements in this Chapter. [49 CFR 192.1003(a)]

B. Exceptions. This subpart does not apply to: [49 CFR 192.1003(b)

1. Individual service lines directly connected to a production line or a gathering line other than a regulated onshore gathering line as determined in §508; [49 CFR 192.1003(b)(1)]

2. Individual service lines directly connected to either a transmission or regulated gathering pipeline and maintained in accordance with §2940.A and B; and [49 CFR 192.1003(b)(2)]

3. Master meter systems. [49 CFR 192.1003(b)(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 38:123 (January 2012), amended LR 44:1044 (June 2018), LR. 47:1146 (August 2021), repromulgated LR 47:1332 (September 2021).

§3505. What must a Gas Distribution Operator (other than a Small LPG Operator) do to Implement this Chapter? [49 CFR 192.1005]

A. No later than August 2, 2011 a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in §3507. [49 CFR 192.1005]

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 38:123 (January 2012), repromulgated LR 47:1146 (August 2021).

§3507. What are the Required Elements of an Integrity Management Plan? [49 CFR 192.1007]

A. A written integrity management plan must contain procedures for developing and implementing the following elements. [49 CFR 192.1007]

1. Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.[49 CFR 192.1007(a)]

a. Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline. [49 CFR 192.1007(a)(1)]

b. Consider the information gained from past design, operations, and maintenance. [49 CFR 192.1007(a)(2)]

c. Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities). [49 CFR 192.1007(a)(3)]

d. Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed. [49 CFR 192.1007(a)(4)]

e. Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed. [49 CFR 192.1007(a)(5)]

2. Identify Threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material, or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience. [49 CFR 192.1007(b)]

3. Evaluate and Rank Risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk. [49 CFR 192.1007(c)]

4. Identify and Implement Measures to Address Risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found). [49 CFR 192.1007(d)]

5. Measure Performance, Monitor Results, and Evaluate Effectiveness [49 CFR 192.1007(e)]

a. Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following: [49 CFR 192.1007(e)(1)]

i. number of hazardous leaks either eliminated or repaired as required by §2903.C of this Subpart (or total number of leaks if all leaks are repaired when found), categorized by cause; [49 CFR 192.1007(e)(1)(i)]

ii. number of excavation damages; [49 CFR 192.1007(e)(1)(ii)]

iii. number of excavation tickets (receipt of information by the underground facility operator from the notification center); [49 CFR 192.1007(e)(1)(iii)]

iv. total number of leaks either eliminated or repaired, categorized by cause; [49 CFR 192.1007(e)(1)(iv)]

v. number of hazardous leaks either eliminated or repaired as required by §2903.C (or total number of leaks if all leaks are repaired when found), categorized by material; and [49 CFR 192.1007(e)(1)(v)]

vi. any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat. [49 CFR 192.1007(e)(1)(vi)]

6. Periodic Evaluation and Improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations. [49 CFR 192.1007(f)]

7. Report Results. Report, on an annual basis, the four measures listed in Clauses 5.a.i through 5.a.iv of this Section, as part of the annual report required by §311 of this Part. An operator also must report the four measures to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline. [49 CFR 192.1007(g)]

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 38:123 (January 2012), amended LR. 47:1146 (August 2021).

§3511. What records must an operator keep? [49 CFR 192.1011]

A. An operator must maintain records demonstrating compliance with the requirements of this chapter for at least 10 years. The records must include copies of superseded integrity management plans developed under this chapter. [49 CFR 192.1011]

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).

§3513. When may an operator deviate from required periodic inspections under this subpart? [49 CFR 192.1013]

A. An operator may propose to reduce the frequency of periodic inspections and tests required in this Subpart on the basis of the engineering analysis and risk assessment required by this Chapter. [49 CFR 192.1013(a)]

B. An operator must submit its proposal to the PHMSA Associate Administrator for Pipeline Safety or, in the case of an intrastate pipeline facility regulated by the State, the appropriate state agency. The applicable oversight agency may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety. [49 CFR 192.1013(b)]

C. An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections. [49 CFR 192.1013(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 38:124 (January 2012).

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

A. General. No later than August 2, 2011 a small LPG operator must develop and implement an IM program that includes a written IM plan as specified in Subsection B of this Section. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines. [49 CFR 192.1015(a)]

B. Elements. A written integrity management plan must address, at a minimum, the following elements. [49 CFR 192.1015(b)]

1. Knowledge. The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities). [49 CFR 192.1015(b)(1)]

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

3. Rank Risks. The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat. [49 CFR 192.1015(b)(3)]

4. Identify and Implement Measures to Mitigate Risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline. [49 CFR 192.1015(b)(4)]

5. Measure Performance, Monitor Results, and Evaluate Effectiveness. The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes. [49 CFR 192.1015(b)(5)]

6. Periodic Evaluation and Improvement. The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five years. The operator must consider the results of the performance monitoring in these evaluations. [49 CFR 192.1015(b)(6)]

C. Records. The operator must maintain, for a period of at least 10 years, the following records: [49 CFR 192.1015(c)]

1. a written IM plan in accordance with this Section, including superseded IM plans; [49 CFR 192.1015(c)(1)]

2. documents supporting threat identification; and [49 CFR 192.1015(c)(2)]

3. documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program. [49 CFR 192.1015(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).

Chapter 51. Appendices

§5101. Reserved.

Editor's Note: The text of this Section (§5101) has been moved to §507 of this Part.

§5103. Appendix B—Qualification of Pipe

I. Listed Pipe Specifications

A. Listed Pipe Specifications

1. API Spec 5L—Steel pipe, “API Specification for Line Pipe” (incorporated by reference, see § 507).

2. ASTM A53/A53M—Steel pipe, “Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-

Coated, Welded and Seamless" (incorporated by reference, see § 507).

3. ASTM A106/A-106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference, see § 507).

4. ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference, see § 507).

5. ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, see § 507).

6. ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion- Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, see § 507).

7. ASTM A672/A672M-09—Steel pipe, "Standard Specification for Electric-Fusion- Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, see § 507).

8. ASTM A691/A691M-09—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High Pressure Service at High Temperatures" (incorporated by reference, see § 507).

9. ASTM D2513"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see § 507).

10. ASTM D 2517-00—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, see § 507).

11. ASTM F2785-12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings" (PA-12) (incorporated by reference, see § 507).

12. ASTM F2817-10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference, see § 507).

13. ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings" (PA-11) (incorporated by reference, see § 507).

B. Other Listed Specifications for Components

1. ASME B16.40-2008 "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems" (incorporated by reference, see § 507).

2. ASTM D2513"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see § 507).

3. ASTM D 2517-00—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, see § 507).

4. ASTM F2785-12 "Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing, and Fittings" (PA-12) (incorporated by reference, see § 507).

5. ASTM F2945-12a "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing, and Fittings" (PA-11) (incorporated by reference, see § 507).

6. ASTM F1055-98 (2006) "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (incorporated by reference, see § 507).

7. ASTM F1924-12 "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing" (incorporated by reference, see § 507).

8. ASTM F1948-12 "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing" (incorporated by reference, see § 507).

9. ASTM F1973-13 "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems" (incorporated by reference, see § 507).

10. ASTM F 2600-09 "Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing" (incorporated by reference, see § 507).

11. ASTM F2145-13 "Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing" (incorporated by reference, see § 507).

12. ASTM F2767-12 "Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution" (incorporated by reference, see §507).

13. ASTM F2817-10 "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference, see §507).

II. Steel Pipe of Unknown or Unlisted Specification

A. Bending properties. For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53, except that the number of tests must be at least equal to the minimum required in Paragraph II.D of this appendix to determine yield strength.

B. Weldability. A girth weld must be made in the pipe by a welder who is qualified under Chapter 13 of this Subpart. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, see §507). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with Section IX of the ASME Boiler and Pressure Vessel Code (IBR, see §507). The same number of chemical tests must be made as are required for testing a girth weld.

C. Inspection. The pipe must be cleaned enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. Tensile properties. If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile test as set forth in API Specification 5L (incorporated by reference, see §507).

Number of Tensile Tests-All Sizes	
10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §705.C5(c).

III. Steel Pipe Manufactured before November 12, 1970, to Earlier Editions of Listed Specifications

Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in Section I of this Appendix, is qualified for use under this Part if the following requirements are met.

A. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. Similarity of Specification Requirements. The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in Section I of this Appendix:

1. physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties;

2. chemical properties of pipe and testing requirements to verify those properties.

C. Inspection or Test of Welded Pipe. On pipe with welded seams, one of the following requirements must be met.

1. The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards of acceptance or rejection and repair as a later edition of the specification listed in Section I of this Appendix.

2. The pipe must be tested in accordance with Chapter 23 of this Part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a Class I location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a Class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Chapter 23 of this Part, the test pressure must be maintained for at least eight hours.

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 10:541 (July 1984), amended LR 18:859 (August 1992), LR 27:1551, 1552 (September 2001), LR 30:1287 (June 2004), LR 31:689 (March 2005), LR 33:487 (March 2007), LR 35:2813 (December 2009), amended by the Department of Natural Resources, Office of Conservation, LR 38:125 (January 2012), LR 44:1045 (June 2018), LR 46:1601 (November 2020), repromulgated LR 47:1148 (August 2021).

§5105. Appendix C—Qualification of Welders for Low Stress Level Pipe

I. Basic Test

The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1/8-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. A welder who successfully passes a butt-weld qualification test under this Section shall be qualified to weld on all pipe diameters less than or equal to 12 inches.

II. Additional Tests for Welders of Service Line Connections to Mains

A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. Periodic Tests for Welders of Small Service Lines

Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows.

1. One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

2. The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in Subparagraph 1, of this Paragraph.

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 10:543 (July 1984), amended LR 18:860 (August 1992), LR 27:1552 (September 2001), LR 30:1288 (June 2004), LR 31:690 (March 2005).

§5107. Appendix D—Criteria for Cathodic Protection and Determination of Measurements

I. Criteria for Cathodic Protection

A. Steel, Cast Iron, and Ductile Iron Structures

1. A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-coppersulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with Sections II and IV of this Appendix.

2. A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with Sections II and IV of this Appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

3. A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with Sections III and IV of this Appendix.

4. A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with Section IV of this Appendix.

5. A net protective current from the electrolyte into the structure surface as measured by the earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. Aluminum Structures

1. Except as provided in Paragraphs 3 and 4. of this Paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current The voltage shift must be determined in accordance with Sections II and IV of this Appendix.

2. Except as provided in Paragraphs 3 and 4. of this Paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with Sections III and IV of this Appendix.

3. Notwithstanding the alternative minimum criteria in Paragraphs 1 and 2 of this Paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with Section IV of this Appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the build-up of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

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

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

D. Metals of Different Anodic Potentials. A negative (cathodic) voltage, measured in accordance with Section IV. of this Appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by Paragraphs 3 and 4 of Paragraph B of this Section, they must be electrically isolated with insulting flanges, or the equivalent.

II. Interpretation of Voltage Measurement

Voltage (IR) drops other than those across the structure electrolyte boundary must be considered for valid interpretation of the voltage measurement in Paragraphs A.1 and 2 and Paragraph B.1 of this Section I of this Appendix.

III. Determination of Polarization Voltage Shift

The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in Paragraphs A.3 and B.2 and C of Section I of this Appendix.

IV. Reference Half Cells

A. Except as provided in Paragraphs B and C of this Section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell Two commonly used reference half cells are listed below along with their voltage equivalent to -0.85 volt as referred to a saturated copper-copper sulfate half cell.

1. Saturated KC1 calomel half cell: -0.78 volt

2. Silver-silver chloride half cell used in sea water: -0.80 volt

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

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 10:544 (July 1984), amended LR 18:860 (August 1992), LR 27:1553 (September 2001), amended LR 30:1288 (June 2004).

§5109. Appendix E—Guidance on Determining High Consequence Areas and on Carrying out Requirements in the Integrity Management Rule

I. Guidance on Determining a High Consequence Area

To determine which segments of an operator's transmission pipeline system are covered for purposes of the integrity management program requirements, an operator must identify the high consequence areas. An operator must use Method (1) or (2) from the definition in §3303 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. (Refer to Figure E.I.A for a diagram of a high consequence area).

Determining High Consequence Area

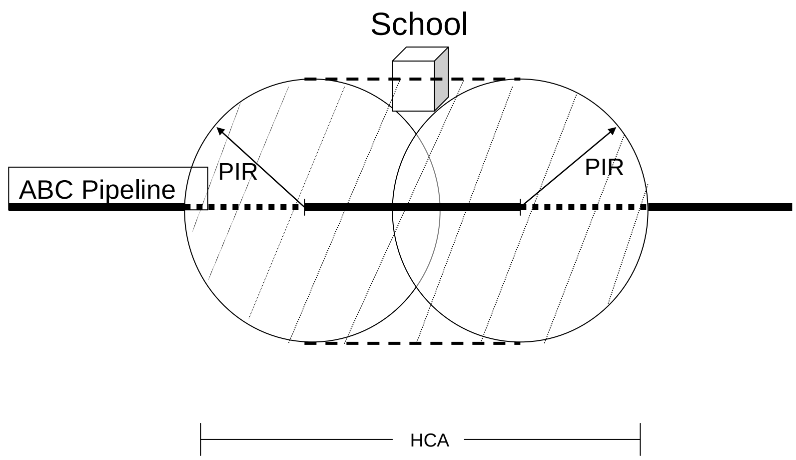

Figure E.I.A

II. Guidance on Assessment Methods and Additional Preventive and Mitigative Measures for Transmission Pipelines

1. Table E.II.1 gives guidance to help an operator implement requirements on additional preventive and mitigative measures for addressing time dependent and independent threats for a transmission pipeline operating below 30 percent SMYS not in an HCA (i.e., outside of potential impact circle) but located within a Class 3 or Class 4 Location.

2. Table E.II.2 gives guidance to help an operator implement requirements on assessment methods for addressing time dependent and independent threats for a transmission pipeline in an HCA.

3. Table E.II.3 gives guidance on preventative and mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30 percent SMYS, in HCAs.

Table E.II.1: Preventative and Mitigative Measures for Transmission Pipelines Operating below 30 Percent SMYS Not in an HCA but in a Class 3 or Class 4 Location			
	Existing Subpart 3 Requirements		(Column 4) Additional (to Subpart 3 requirements) Preventive and Mitigative Measures
(Column 1) Threat	(Column 2) Primary	(Column 3) Secondary	
External Corrosion	2107-(Gen. Post 1971) 2109-(Gen. Pre-1971) 2111-(Examination) 2113-(Ext. coating) 2115-(CP) 2117-(Monitoring) 2119-(Elect isolation) 2121-Test stations) 2123-(Test leads) 2125-(Interference) 2131-(Atmospheric) 2133-(Atmospheric) 2137-(Remedial) 2905-(Patrol) 2906-(Leak survey) 2911 (RepairBgen.) 2917-(RepairBperm.)	2703-(Gen Operation) 2713-(Surveillance)	For Cathodically Protected Transmission Pipeline: • Perform semi-annual leak surveys. For Unprotected Transmission Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impractical: • Perform quarterly leak surveys
Internal Corrosion	2127-(Gen IC), 2129-(IC monitoring) 2137-(Remedial), 2905-(Patrol) 2906-(Leak survey), 2911-(Repair B gen.) 2917-(Repair B perm.)	703(A)-(Materials) 2703-(Gen Operation) 2713-(Surveillance)	• Perform semi-annual leak surveys.

<table>
<tr><th colspan="4">Table E.II.1: Preventative and Mitigative Measures for Transmission Pipelines Operating below 30 Percent SMYS Not in an HCA but in a Class 3 or Class 4 Location</th></tr>
<tr><td>3rd Party Damage</td><td>903-(Gen. Design),
911-(Design factor)
1717-(Hazard prot),
1727-(Cover)
2714-(Dam. Prevent),
2716-(Public education)
2905-(Patrol),
2907-(Line markers)
2911-(Repair B gen.),
2917-(Repair B perm.)</td><td>2715B(Emerg. Plan)</td><td>• Participation in state one-call system,

• Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND

• Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.</td></tr>
</table>

<table>
<tr><th colspan="7">Table E.II.2 Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment intervals are maximum allowed.)</th></tr>
<tr><th></th><th colspan="6">Re-Assessment Requirements (see Note 3)</th></tr>
<tr><th></th><th colspan="2">At or above 50 Percent SMYS</th><th colspan="2">At or above 30 Percent SMYS up to 50 Percent SMYS</th><th colspan="2">Below 30 Percent SMYS</th></tr>
<tr><td>Baseline Assessment Method (see Note 3)</td><td>Max Re-Assessment Interval</td><td>Assessment Method</td><td>Max Re-Assessment Interval</td><td>Assessment Method</td><td>Max Re-Assessment Interval</td><td>Assessment Method</td></tr>
<tr><td rowspan="5">Pressure Testing</td><td>7</td><td>CDA</td><td>7</td><td>CDA</td><td rowspan="3">Ongoing</td><td>Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)</td></tr>
<tr><td>10</td><td>Pressure Test or ILI or DA</td><td></td><td></td><td></td></tr>
<tr><td></td><td rowspan="3">Repeat inspection cycle every 10 years</td><td>15 (see Note 1)</td><td>Pressure Test or ILI or DA (see Note 1)</td><td></td></tr>
<tr><td></td><td></td><td rowspan="2">Repeat inspection cycle every 15 years</td><td>20</td><td>Pressure Test or ILI or DA</td></tr>
<tr><td></td><td></td><td></td><td>Repeat inspection cycle every 20 years</td></tr>
<tr><td>In-Line Inspection</td><td>7</td><td>CDA</td><td>7</td><td>CDA</td><td rowspan="3">Ongoing</td><td>Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)</td></tr>
<tr><td rowspan="4"></td><td>10</td><td>ILI or DA or Pressure Test</td><td></td><td></td><td rowspan="2"></td></tr>
<tr><td></td><td rowspan="3">Repeat inspection cycle every 10 years</td><td>15 (see Note 1)</td><td>ILI or DA or Pressure Test (see Note 1)</td></tr>
<tr><td></td><td></td><td rowspan="2">Repeat inspection cycle every 15 years</td><td>20</td><td>ILI or DA or Pressure Test</td></tr>
<tr><td></td><td></td><td></td><td>Repeat inspection cycle every 20 years</td></tr>
<tr><td>Direct Assessment</td><td>7</td><td>CDA</td><td>7</td><td>CDA</td><td rowspan="3">Ongoing</td><td>Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)</td></tr>
<tr><td rowspan="4"></td><td>10</td><td>DA or ILI or Pressure Test</td><td></td><td></td><td rowspan="2"></td></tr>
<tr><td></td><td rowspan="3">Repeat inspection cycle every 10 years</td><td>15 (see Note 1)</td><td>DA or ILI or Pressure Test (see Note 1)</td></tr>
<tr><td></td><td></td><td rowspan="2">Repeat inspection cycle every 15 years</td><td>20</td><td>DA or ILI or Pressure Test</td></tr>
<tr><td></td><td></td><td></td><td>Repeat inspection cycle every 20 years</td></tr>
<tr><td colspan="7">Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S
Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M
Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe"</td></tr>
</table>

Table E.II.3

Preventative and Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate below 30 Percent SMYS, in HCAs

Threat	Existing Subpart 3 Requirements		Additional (to Subpart 3 requirements) Preventive and Mitigative Measures
	Primary	Secondary	
External Corrosion	2107-(Gen. Post 1971) 2109-(Gen. Pre-1971) 2111-(Examination) 2113-(Ext. coating) 2115-(CP) 2117-(Monitoring) 2119-(Elect isolation) 2121-Test stations) 2123-(Test leads) 2125-(Interference) 2131-(Atmospheric) 2133-(Atmospheric) 2137-(Remedial) 2905-(Patrol) 2906-(Leak survey) 2911-(RepairBgen.) 2917-(RepairBperm.)	2703-(Gen Oper) 2713-(Surveil)	For Cathodically Protected Trmn. Pipelines • Perform an electrical survey (i.e., indirect examination tool/method) at least every seven years. Results are to be utilized as part of an overall evaluation of the CP system and corrosion threat for the covered segment. Evaluation shall include consideration of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment. For Unprotected Trmn. Pipelines or for Cathodically Protected Pipe where Electrical Surveys are Impracticable • Conduct quarterly leak surveys AND • Every 1 1/2 years, determine areas of active corrosion by evaluation of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
Internal Corrosion	2127-(Gen IC) 2129-(IC monitoring) 2137-(Remedial) 2905-(Patrol) 2906-(Leak survey) 2911-(RepairBgen.) 2917-(RepairBperm.)	703(A)-(Materials) 2703-(Gen Oper) 2713-(Surveil)	• Obtain and review gas analysis data each calendar year for corrosive agents from transmission pipelines in HCAs, • Periodic testing of fluid removed from pipelines. Specifically, once each calendar year from each storage field that may affect transmission pipelines in HCAs, AND • At least every seven years, integrate data obtained with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records.
3rd Party Damage	903-(Gen. Design) 911-(Design factor) 1717-(Hazard prot) 1727-(Cover) 2714-(Dam. Prevent) 2716-(Public educat) 2905-(Patrol) 2909-(Line markers) 2911-(RepairBgen.) 2917-(RepairBperm.)	2715B(Emerg Plan)	• Participation in state one-call system, • Use of qualified operator employees and contractors to perform marking and locating of buried structures and in direct supervision of excavation work, AND • Either monitoring of excavations near operator's transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or Class 3 and 4 locations. Any indications of unreported construction activity would require a follow up investigation to determine if mechanical damage occurred.

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 30:1289 (June 2004), amended LR 31:690 (March 2005).

§5111. Appendix F—Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

This appendix defines criteria which must be properly implemented for use of guided wave ultrasonic testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered "other technology" as described by §§ 2910 .C.7, 3321.A.7, and 3337.C.7, for which OPS must be notified 90 days prior to use in accordance with §§ 3321.A.7 or 3337.C.7. GWUT in the "Go-No Go" mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested, or replaced prior to completing the integrity assessment on the carrier pipe.

I. Equipment and Software: Generation. The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.

II. Inspection Range. The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/ N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. Complete Pipe Inspection. To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double-ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. Sensitivity. The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

All defect indications in the "Go-No Go" mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. Wave Frequency. Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. Signal or Wave Type: Torsional and Longitudinal. Both torsional and longitudinal waves must be used and use must be documented.

VII. Distance Amplitude Correction (DAC) Curve and Weld Calibration. The distance amplitude correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross-sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. Dead Zone. The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B- scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. Near Field Effects. The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B- scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. Coating Type. Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the pipe, then another type of assessment method must be utilized.

XI. End Seal. When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator's corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. Weld Calibration to set DAC Curve. Accessible welds, along or outside the pipeline segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipeline segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible.

Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by a documented engineering analysis and evaluation.

XIII. Validation of Operator Training. Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

A. Equipment operation,

B. field data collection, and

C. data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment. A senior-level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior-level GWUT equipment operator must have additional training and experience, including training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see § 507).

XIV. Training and Experience Minimums for Senior Level GWUT Equipment Operators:

Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe

Training, qualification and experience in testing procedures and frequency determination

Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)

Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. Equipment: Traceable from vendor to inspection company. An operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XVI. Calibration Onsite. The GWUT equipment must be calibrated for performance in accordance with the manufacturer's requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated to a different casing or pipeline segment. If on-site diagnostics show a discrepancy with the manufacturer's requirements and specifications, testing must cease until the equipment can be restored to manufacturer's specifications.

XVII. Use on Shorted Casings (direct or electrolytic). GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (see § 192.605) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator's standard operating procedures.

XVIII. Direct examination of all indications above the detection sensitivity threshold. The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5 percent of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe or other GWUT application. If this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XIX. Timing of direct examination of all indications above the detection sensitivity threshold. Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

Required Response to GWUT Indications			
GWUT criterion	**Operating pressure less than or equal to 30% SMYS**	**Operating pressure over 30 and less than or equal to 50% SMYS**	**Operating pressure over 50% SMYS**
Over the detection sensitivity threshold (maximum of 5% CSA).	Replace or direct examination within 12 months, and instrumented leak survey once every 30 calendar days.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and maintain MAOP below the operating pressure at time of discovery.	Replace or direct examination within 6 months, instrumented leak survey once every 30 calendar days, and reduce MAOP to 80% of operating pressure at time of discovery.

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 46:1602 (November 2020).

Subpart 4. Drug and Alcohol Testing

Chapter 61. General [Part 199—Subpart A]

§6101. Scope [49 CFR 199.1]

A. This Subpart requires operators of pipeline facilities subject to LAC 43:XIII or LAC 33:V.Subpart 3 (49 CFR Part 192 and 195) to test covered employees for the presence of prohibited drugs and alcohol. [49 CFR 199.1]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 16:134 (February 1990), repromulgated LR 16:532 (June 1990), amended LR 18:852 (August 1992), LR 21:826 (August 1995), LR 27:1554 (September 2001), LR 30:1292 (June 2004).

§6102. Applicability [49 CFR 199.2]

A. This Subpart applies to pipeline operators' only with respect to employees located within the territory of the United States, including those employees located 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). [49 CFR 199.2(a)]

B. This Subpart does not apply to any person for whom compliance with LAC 43:XIII or LAC 33:V.Subpart 3 (49 CFR Part 192 and 195) would violate the domestic laws or policies of another country [49 CFR 199.2(b)].

C. This Subpart does not apply to covered functions performed on: [49 CFR 199.2(c)]

1. master meter systems, as defined in §303 of this Part; or [49 CFR 199.2(c)(1)]

2. pipeline systems that transport only petroleum gas or petroleum gas/air mixtures. [49 CFR 199.2(c)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

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§6103. Definitions [49 CFR 199.3]

A. As used in this Chapter:

Accident—an incident reportable under 49 CFR Part 191 involving gas pipeline facilities or LNG facilities, or an accident reportable under CFR Part 195 involving hazardous liquid pipeline facilities.

Administrator—the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

Covered Employee, Employee, or Individual to be Tested—a person who performs a covered function, including persons employed by operators, contractors engaged by operators, and persons employed by such contractors.

Covered Function—an operations, maintenance, or emergency-response function regulated by 49 CFR Part 192, 193, or 195 that is performed on a pipeline or on an LNG facility.

DOT Procedures—the "Procedures for Transportation Workplace Drug and Alcohol Testing Programs" published by the Office of the Secretary of Transportation in CFR Part 40.

Fail a Drug Test—the confirmation test result shows positive evidence of the presence under DOT procedures of a prohibited drug in an employee's system.

Operator—a person who owns or operates pipeline facilities subject to CFR Part 192, 193, or 195.

Pass a Drug Test—initial testing or confirmation testing under DOT procedures does not show evidence of the presence of a prohibited drug in a person's system.

Performs a Covered Function—includes actually performing, ready to perform, or immediately available to perform a covered function.

Positive Rate for Random Drug Testing—the number of verified positive results for random drug tests conducted under this Subpart plus the number of refusals of random drug tests required by this Subpart, divided by the total number of random drug tests results (i.e., positives, negatives, and refusals) under this Subpart.

Prohibited Drug—any of the substances specified in 49 CFR part 40.

Refuse to Submit, Refuse, or Refuse to Take—behavior consistent with DOT procedures concerning refusal to take a drug test of refusal to take an alcohol test.

State Agency—an agency of any of the several states, the District of Columbia, or Puerto Rico that participates under the pipeline safety laws. (49 U.S.C. 60101 et seq.)

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

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§6105. DOT Procedures [49 CFR 199.5]

A. The anti-drug and alcohol programs required by this Subpart must be conducted according to the requirements of this Subpart and the DOT procedures. Terms and concepts used in this Subpart have the same meaning as in the DOT procedures. Violations of DOT procedures with respect to anti-drug and alcohol programs required by this Subpart are violations of this Subpart. [49 CFR 199.5]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 16:134 (February 1990), repromulgated LR 16:533 (June 1990), amended LR 30:1292 (June 2004).

§6107. Stand-Down Waivers [49 CFR 199.7]

A. Each operator who seeks a waiver under 49 CFR §40.21 from the stand-down restriction must submit an application for waiver in duplicate to the Associate Administrator for Pipeline Safety, *Pipeline and Hazardous Materials Safety Administration*, U.S. Department of Transportation, 1200 New Jersey Avenue, SE, Washington, DC 20590-0001 [49 CFR 199.7(a)].

B. Each applicant must: [49 CFR 199.7(b)]

1. identify 49 CFR 40.21 as the rule from which the waiver is sought; [49 CFR 199.7(b)(1)]

2. explain why the waiver is requested and describe the employees to be covered by the waiver; [49 CFR 199.7(b)(2)]

3. contain the information required by 49 CFR §40.21 and any other information or arguments to support the waiver requested; and [49 CFR 199.7(b)(3)]

4. unless good cause is shown in the application, be submitted at least 60 days before the proposed effective date of the waiver. [49 CFR 199.7(b)(4)]

C. No public hearing or other proceeding is held directly on an application before its disposition under this Section. If the associate administrator determines that the application contains adequate justification, he or she grants the waiver. If the associate administrator determines that the application does not justify granting the waiver, he or she denies the application. The associate administrator notifies each applicant of the decision to grant or deny an application. [49 CFR 199.7(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 30:1293 (June 2004), amended LR 33:488 (March 2007), LR 35:2813 (December 2009).

§6109. Preemption of State and Local Laws [49 CFR 199.9]

A. Except as provided in Subsection B of this Section, this Subpart preempts any state or local law, rule, regulation, or order to the extent that: [49 CFR 199.9(a)]

1. compliance with both the state or local requirement and this Subpart is not possible; [49 CFR 199.9(a)(1)]

2. compliance with the state or local requirement is an obstacle to the accomplishment and execution of any requirement in this Subpart; or [49 CFR 199.9(a)(2)]

3. the state or local requirement is a pipeline safety standard applicable to interstate pipeline facilities. [49 CFR 199.9(a)(3)]

B. This Chapter shall not be construed to preempt provisions of state criminal law that impose sanctions for reckless conduct leading to actual loss of life, injury, or damage to property, whether the provisions apply specifically to transportation employees or employers or to the general public. [49 CFR 199.9(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:829 (August 1995), amended LR 30:1293 (June 2004).

Chapter 63. Drug Testing [49 CFR Part 192 Subpart B]

§6300. Purpose [49 CFR 199.100]

A. The purpose of this Chapter is to establish programs designed to help prevent accidents and injuries resulting from the use of prohibited drugs by employees who perform covered functions for operators of certain pipeline facilities subject to LAC 43:XIII, and LAC 33:V Subpart 3 [49 CFR Part 192, 193, or 195]. [49 CFR 199.100]

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§6301. Anti-Drug Plan [49 CFR 199.101]

A. Each operator shall maintain and follow a written anti-drug plan that conforms to the requirements of this Chapter and the DOT procedures. The plan must contain: [49 CFR 199.101(a)]

1. methods and procedures for compliance with all the requirements of this Chapter, including the employee assistance program; [49 CFR 199.101(a)(1)]

2. the name and address of each laboratory that analyzes the specimens collected for drug testing; and [49 CFR 199.101(a)(2)]

3. the name and address of the operator's medical review officer and, substance abuse professional; and [49 CFR 199.101(a)(3)]

4. procedures for notifying employees of the coverage and provisions of the plan. [49 CFR 199.101(a)(4)]

B. The administrator or the state agency that has submitted a current certification under the pipeline safety laws (49 U.S.C. 60101 et seq.) With respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant state procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety. [49 CFR 199.101(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

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§6303. Use of Persons Who Fail or Refuse a Drug Test [49 CFR 199.103]

A. An operator may not knowingly use as an employee any person who: [49 CFR 199.103(a)]

1. fails a drug test required by this Chapter and the medical review officer makes a determination under DOT procedures; or [49 CFR 199.103(a)(1)]

2. refuses to take a drug test required by this Chapter. [49 CFR 199.103(a)(2)]

B. Paragraph A.1 of this Section does not apply to a person who has: [49 CFR 199.103(b)]

1. passed a drug test under DOT procedures; [49 CFR 199.103(b)(1)]

2. been considered by the medical review officer in accordance with DOT procedures and been determined by a substance abuse professional to have successfully completed required education or treatment; and [49 CFR 199.103(b)(2)]

3. not failed a drug test required by this Chapter after returning to duty. [49 CFR 199.103(b)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 16:135 (February 1990), repromulgated LR 16:533 (June 1990), amended LR 30:1293 (June 2004).

§6305. Drug Tests Required [49 CFR 199.105]

A. Each operator shall conduct the following drug tests for the presence of a prohibited drug. [49 CFR 199.105]

1. Pre-Employment Testing. No operator may hire or contract for the use of any person as an employee unless that person passes a drug test or is covered by an anti-drug program that conforms to the requirements of this Chapter. [49 CFR 199.105(a)]

2. Post-Accident Testing [49 CFR 199.105(b)]

a. As soon as possible but no later than 32 hours after an accident, an operator must drug test each surviving covered employee whose performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may decide not to test under this Subparagraph but such a decision must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident. [49 CFR 199.105(b)(1)]

b. If a test required by this section is not administered within the 32 hours following the accident, the operator must prepare and maintain its decision stating the reasons why the test was not promptly administered. If a test required by Paragraph B.1 of this Section is not administered within 32 hours following the accident, the operator must cease attempts to administer a drug test and must state in the record the reasons for not administering the test. [49 CFR 199.105(b)(2)]

3. Random Testing [49 CFR 199.105(c)].

a. Except as provided in Subparagraph 3.b through d of this Subsection, the minimum annual percentage rate for random drug testing shall be 50 percent of covered employees. [49 CFR 199.105(c)(1)]

b. The administrator's decision to increase or decrease the minimum annual percentage rate for random drug testing is based on the reported positive rate for the entire industry. All information used for this determination is drawn from the drug MIS reports required by this Chapter. In order to ensure reliability of the data, the administrator considers the quality and completeness of the reported data, may obtain additional information or reports from operators, and may make appropriate modifications in calculating the industry positive rate. Each year, the administrator will publish in the *Federal Register* the minimum annual percentage rate for random drug testing of covered employees. The new minimum annual percentage rate for random drug testing will be applicable starting January 1 of the calendar year following publication. [49 CFR 199.105(c)(2)]

c. When the minimum annual percentage rate for random drug testing is 50 percent, the administrator may lower this rate to 25 percent of all covered employees if the administrator determines that the data received under the reporting requirements of §6319 for two consecutive calendar years indicate that the reported positive rate is less than 1 percent. [49 CFR 199.105(c)(3)]

d. When the minimum annual percentage rate for random drug testing is 25 percent, and the data received under the reporting requirements of §6319 for any calendar year indicate that the reported positive rate is equal to or greater than 1 percent, the administrator will increase the minimum annual percentage rate for random drug testing to 50 percent of all covered employees. [49 CFR 199.105(c)(4)]

e. The selection of employees for random drug testing shall be made by a scientifically valid method, such as a random number table or a computer-based random number generator that is matched with employees' social security numbers, payroll identification numbers, or other comparable identifying numbers. Under the selection process used, each covered employee shall have an equal chance of being tested each time selections are made. [49 CFR 199.105(c)(5)]

f. The operator shall randomly select a sufficient number of covered employees for testing during each calendar year to equal an annual rate not less than the minimum annual percentage rate for random drug testing determined by the administrator. If the operator conducts random drug testing through a consortium, the number of employees to be tested may be calculated for each individual operator or may be based on the total number of covered employees covered by the consortium who are subject to random drug testing at the same minimum annual percentage rate under this Chapter or any DOT drug testing rule. [49 CFR 199.105(c)(6)]

g. Each operator shall ensure that random drug tests conducted under this Chapter are unannounced and that the dates for administering random tests are spread reasonably throughout the calendar year. [49 CFR 199.105(c)(7)]

h. If a given covered employee is subject to random drug testing under the drug testing rules of more than one DOT agency for the same operator, the employee shall be subject to random drug testing at the percentage rate established for the calendar year by the DOT agency regulating more than 50 percent of the employee's function. [49 CFR 199.105(c)(8)]

i. If an operator is required to conduct random drug testing under the drug testing rules of more than one DOT agency, the operator may: [49 CFR 199.105(c)(9)]

i. establish separate pools for random selection, with each pool containing the covered employees who are subject to testing at the same required rate; or [49 CFR 199.105(c)(9)(i)]

ii. randomly select such employees for testing at the highest percentage rate established for the calendar year by any DOT agency to which the operator is subject. [49 CFR 199.105(c)(9)(ii)]

4. Testing Based on Reasonable Cause. Each operator shall drug test each employee when there is reasonable cause to believe the employee is using a prohibited drug. The decision to test must be based on a reasonable and articulable belief that the employee is using a prohibited drug on the basis of specific, contemporaneous physical, behavioral, or performance indicators of probable drug use. At least two of the employee's supervisors, one of whom is trained in detection of the possible symptoms of drug use, shall substantiate and concur in the decision to test an employee. The concurrence between the two supervisors may be by telephone. However, in the case of operators with 50 or fewer employees subject to testing under this Chapter, only one supervisor of the employee trained in detecting possible drug use symptoms shall substantiate the decision to test. [49 CFR 199.105(d)]

5. Return-to-Duty. A covered employee who refuses to take or has a positive drug test may not return to duty in the covered function until the covered employee has complied with applicable provisions of DOT procedures concerning substance abuse professionals and the return-to-duty process. [49 CFR 199.105(e)]

6. Follow-Up Testing. A covered employee refuses to take or has a positive drug test shall be subject to unannounced follow-up drug tests administered by the operator following the covered employee's return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional, but shall consist of at least six tests in the first 12 months following the covered employee's return to duty. In addition, follow-up testing may include testing for alcohol as directed by the substance abuse professional, to be performed in accordance with 49 CFR Part 40. Follow-up testing shall not exceed 60 months from the date of the covered employee's return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substance abuse professional determines that such testing is no longer necessary. [49 CFR 199.105(f)]

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§6307. Drug Testing Laboratory [49 CFR 199.107]

A. Each operator shall use for the drug testing required by this Chapter only drug testing laboratories certified by the Department of Health and Human Services under the DOT procedures. [49 CFR 199.107(a)]

B. The drug testing laboratory must permit: [49 CFR 199.107(b)]

1. inspections by the operator before the laboratory is awarded a testing contract; and [49 CFR 199.107(b)(1)]

2. unannounced inspections, including examination of records, at any time, by the operator, the administrator, and if the operator is subject to state agency jurisdiction, a representative of that state agency. [49 CFR 199.107(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 16:135 (February 1990), repromulgated LR 16:534 (June 1990), amended LR 30:1295 (June 2004).

§6309. Review of Drug Testing Results [49 CFR 199.109]

A. MRO Appointment. Each operator shall designate or appoint a medical review officer (MRO). If an operator does not have a qualified individual on staff to serve as MRO, the operator may contract for the provision of MRO services as part of its anti-drug program. [49 CFR 199.109(a)]

B. MRO Qualifications. Each MRO must be a licensed physician who has the qualifications required by DOT procedures. [49 CFR 199.109(b)]

C. MRO Duties. The MRO must perform functions for the operator as required by DOT procedures. [49 CFR 199.109(c)]

D. MRO Reports. The MRO must report all drug test results to the operator in accordance with DOT procedure. [49 CFR 199.109(d)]

E. Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment or costs shall be made in accordance with the operator/employee agreements and operator/employee policies. [49 CFR 199.109(e)]

F. The operator shall ensure that a substance abuse professional, who determines that a covered employee requires assistance in resolving problems with drug abuse, does not refer the covered employee to the substance abuse professional's private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This Subsection does not prohibit a substance abuse professional from referring a covered employee for assistance provided through: [49 CFR 199.109(f)]

1. a public agency, such as state, parish, or municipality; [49 CFR 199.109(f)(1)]

2. the operator or a person under contract to provide treatment for drug problems on behalf of the operator; [49 CFR 199.109(f)(2)]

3. the sole source or therapeutically appropriate treatment under the employee's health insurance program; or [49 CFR 199.109(f)(3)]

4. the sole source of therapeutically appropriate treatment reasonably accessible to the employee. [49 CFR 199.109(f)(4)]

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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 16:135 (February 1990), repromulgated LR 16:534 (June 1990), amended LR 27:1554 (September 2001), LR 30:1295 (June 2004).

§6313. Employee Assistance Program [49 CFR 199.113]

A. Each operator shall provide an employee assistance program (EAP) for its employees and supervisory personnel who will determine whether an employee must be drug tested based on reasonable cause. The operator may establish the EAP as a part of its internal personnel services or the operator may contract with an entity that provides EAP services. Each EAP must include education and training on drug use. At the discretion of the operator, the EAP may include an opportunity for employee rehabilitation. [49 CFR 199.113(a)]

B. Education under each EAP must include at least the following elements: display and distribution of informational material; display and distribution of a community service hot-line telephone number for employee assistance; and display and distribution of the employer's policy regarding the use of prohibited drugs. [49 CFR 199.113(b)]

C. Training under each EAP for supervisory personnel who will determine whether an employee must be drug tested based on reasonable cause must include one 60-minute period of training on the specific, contemporaneous physical, behavioral, and performance indicators of probable drug use. [49 CFR 199.113(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 16:136 (February 1990), repromulgated LR 16:535 (June 1990), amended LR 30:1296 (June 2004).

§6315. Contractor Employees [49 CFR 199.115]

A. With respect to those employees who are contractors or employed by a contractor, an operator may provide by contract that the drug testing, education, and training required by this Chapter be carried out by the contractor provided: [49 CFR 199.115]

1. the operator remains responsible for ensuring that the requirements of this Chapter are complied with; and [49 CFR 199.115(a)]

2. the contractor allows access to property and records by the operator, the administrator, and if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purpose of monitoring the operator's compliance with the requirements of this Chapter. [49 CFR 199.115(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 16:136 (February

1990), repromulgated LR 16:535 (June 1990), amended LR 30:1296 (June 2004).

§6317. Recordkeeping [49 CFR 199.117]

A. Each operator shall keep the following records for the periods specified and permit access to the records as provided by Subsection B of this Section. [49 CFR 199.117(a)]

1. Records that demonstrate the collection process conforms to this Chapter must be kept for at least three years. [49 CFR 199.117(a)(1)]

2. Records of employee drug test that indicate a verified positive result, records that demonstrate compliance with the recommendations of a substance abuse professional, and MIS annual report data shall be maintained for a minimum of five years: [49 CFR 199.117(a)(2)]

a. the function performed by each employee who had a positive drug test; [49 CFR 199.117(a)(2)(i)]

b. the prohibited drugs which were used by an employee who had a positive drug test; [49 CFR 199.117(a)(2)(ii)]

c. the disposition of each employee who had a positive drug test or refused a drug test (e.g., termination, rehabilitation, removed from covered function, other). [49 CFR 199.117(a)(2)(iii)]

3. Records of employee drug test results that show employees passed a drug test must be kept for at least one year. [49 CFR 199.117(a)(3)]

4. Records confirming that supervisors and employees have been trained as required by this Chapter must be kept for at least three years. [49 CFR 199.117(a)(4)]

5. Records of decisions not to administer post-accident employee drug tests must be kept for at least 3 years [49 CFR 199.117(a)(5)]

B. Information regarding an individual's drug testing results or rehabilitation must be released upon written consent of the individual and as provided by DOT procedures. Statistical data related to drug testing and rehabilitation that is not name-specific and training records must be made available to the administrator or the representative of a state agency upon request. [49 CFR 199.117(b)]

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§6319. Reporting of Anti-Drug Testing Results [49 CFR 199.119]

A. Each large operator (having more than 50 covered employees) must submit an annual Management Information System (MIS) report to PHMSA of its anti-drug testing using the MIS form and instructions as required by 49 CFR part 40 (at §40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (https://portal.phmsa.dot.gov/phmsaportallanding) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA. [49 CFR 199.119(a)].

B. Each report required under this section must be submitted electronically at http://damis.dot.gov. An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal (https://portal.phmsa.dot.gov/phmsaportallanding). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received. [49 CFR 199.119(b)].

C. To calculate the total number of covered employees eligible for random testing throughout the year, as an operator, you must add the total number of covered employees eligible for testing during each random testing period for the year and divide that total by the number of random testing periods. Covered employees, and only covered employees, are to be in an employer's random testing pool, and all covered employees must be in the random pool. If you are an employer conducting random testing more often than once per month (e.g., you select daily, weekly, bi-weekly), you do not need to compute this total number of covered employees rate more than on a once per month basis. [49 CFR 199.119(c)]

D. As an employer, you may use a service agent (e.g., C/TPA) to perform random selections for you; and your covered employees may be part of a larger random testing pool of covered employees. However, you must ensure that the service agent you use is testing at the appropriate percentage established for your industry and that only covered employees are in the random testing pool. [49 CFR 199.119(d)]

E. Each operator that has a covered employee who performs multi-DOT agency functions (e.g., an employee performs pipeline maintenance duties and drives a commercial motor vehicle), count the employee only on the MIS report for the DOT agency under which he or she is randomly tested. Normally, this will be the DOT agency under which the employee performs more than 50 percent of his or her duties. Operators may have to explain the testing data for these employees in the event of a DOT agency inspection or audit. [49 CFR 199.119(e)]

F. A service agent (e.g., Consortia/Third Party Administrator as defined in 49 CFR Part 40) may prepare the MIS report on behalf of an operator. However, each report shall be certified by the operator's anti-drug manager or designated representative for accuracy and completeness. [49 CFR 199.119(f)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

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Chapter 65. Alcohol Misuse Prevention Program [49 CFR Part 192 Subpart C]

§6501. Purpose [49 CFR 199.200]

A. The purpose of this Chapter is to establish programs designed to help prevent accidents and injuries resulting from the misuse of alcohol by employees who perform covered functions for operators of certain pipeline facilities subject to LAC 43:XIII, and LAC 33:V Subpart 3 [Parts 192, 193, or 195]. [49 CFR 199.200]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:828 (August 1995), amended LR 30:1297 (June 2004).

§6502. Alcohol Misuse Plan [49 CFR 199.202]

A. Each operator must maintain and follow a written alcohol misuse plan that conforms to the requirements of this part and DOT procedures concerning alcohol testing programs. The plan shall contain methods and procedures for compliance with all the requirements of this Chapter, including required testing, recordkeeping, reporting, education and training elements. [49 CFR 199.202]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:828 (August 1995), amended LR 30:1297 (June 2004).

§6509. Other Requirements Imposed by Operators [49 CFR 199.209]

A. Except as expressly provided in this Chapter, nothing in this Chapter shall be construed to affect the authority of operators, or the rights of employees, with respect to the use or possession of alcohol, including authority and rights with respect to alcohol testing and rehabilitation. [49 CFR 199.209(a)]

B. Operators may, but are not required to, conduct pre-employment alcohol testing under this Subpart. Each operator that conducts pre-employment alcohol testing must: [49 CFR 199.209(b)]

1. conduct a pre-employment alcohol test before the first performance of covered functions by every covered employee (whether a new employee or someone who has transferred to a position involving the performance of covered functions); [49 CFR 199.209(b)(1)]

2. treat all covered employees the same for the purpose of pre-employment alcohol testing (i.e., you must not test some covered employees and not others); [49 CFR 199.209(b)(2)]

3. conduct the pre-employment tests after making a contingent offer of employment or transfer, subject to the employee passing the pre-employment alcohol test; [49 CFR 199.209(b)(3)]

4. conduct all pre-employment alcohol tests using the alcohol testing procedures in DOT procedures; and [49 CFR 199.209(b)(4)]

5. not allow any covered employee to begin performing covered functions unless the results of the employee's test indicates an alcohol concentration of less than 0.04. [49 CFR 199.209(b)(5)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:829 (August 1995), amended LR 30:1297 (June 2004).

§6511. Requirement for Notice [49 CFR 199.211]

A. Before performing an alcohol test under this Chapter, each operator shall notify a covered employee that the alcohol test is required by this Chapter. No operator shall falsely represent that a test is administered under this Chapter. [49 CFR 199.211]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:830 (August 1995), amended LR 30:1297 (June 2004).

§6515. Alcohol Concentration [49 CFR 199.215]

A. Each operator shall prohibit a covered employee from reporting for duty or remaining on duty requiring the performance of covered functions while having an alcohol concentration of 0.04 or greater. No operator having actual knowledge that a covered employee has an alcohol concentration of 0.04 or greater shall permit the employee to perform or continue to perform covered functions. [49 CFR 199.215]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:830 (August 1995), amended LR 30:1298 (June 2004).

§6517. On-Duty Use [49 CFR 199.217]

A. Each operator shall prohibit a covered employee from using alcohol while performing covered functions. No operator having actual knowledge that a covered employee is using alcohol while performing covered functions shall permit the employee to perform or continue to perform covered functions. [49 CFR 199.217]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:830 (August 1995), amended LR 30:1298 (June 2004).

§6519. Pre-Duty Use [49 CFR 199.219]

A. Each operator shall prohibit a covered employee from using alcohol within four hours prior to performing covered functions, or, if an employee is called to duty to respond to an emergency, within the time period after the employee has been notified to report for duty. No operator having actual knowledge that a covered employee has used alcohol within four hours prior to performing covered functions or within the time period after the employee has been notified to report for duty shall permit that covered employee to perform or continue to perform covered functions. [49 CFR 199.219]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:830 (August 1995), amended LR 30:1298 (June 2004).

§6521. Use Following an Accident [49 CFR 199.221]

A. Each operator shall prohibit a covered employee who has actual knowledge of an accident in which his or her performance of covered functions has not been discounted by the operator as a contributing factor to the accident from using alcohol for eight hours following the accident, unless he or she has been given a post-accident test under §6525.A, or the operator has determined that the employee's performance could not have contributed to the accident. [49 CFR 199.221]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:830 (August 1995), amended LR 30:1298 (June 2004).

§6523. Refusal to Submit to a Required Alcohol Test [49 CFR 199.223]

A. Each operator shall require a covered employee to submit to a post-accident alcohol test required under §6525.A.1, a reasonable suspicion alcohol test required under §6525.A.2, or a follow-up alcohol test required under §6525.A.4. No operator shall permit an employee who refuses to submit to such a test to perform or continue to perform covered functions. [49 CFR 199.223]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:830 (August 1995), amended LR 30:1298 (June 2004).

§6525. Alcohol Tests Required [49 CFR 199.225]

A. Each operator shall conduct the following types of alcohol tests for the presence of alcohol. [49 CFR 199.225]

1. Post-Accident [49 CFR 199.225(a)]

a. As soon as practicable following an accident, each operator must test each surviving covered employee for alcohol if that employee's performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. The decision not to administer a test under this section must be based on specific information that the covered employee's performance had no role in the cause(s) or severity of the accident. [49 CFR 199.225(a)(1)]

b. If a test required by this Section is not administered within two hours following the accident, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by Paragraph A.1 is not administered within eight hours following the accident, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test. [49 CFR 199.225(a)(2)(i)]

c. A covered employee who is subject to post-accident testing who fails to remain readily available for such testing, including notifying the operator or operator representative of his/her location if he/she leaves the scene of the accident prior to submission to such test, may be deemed by the operator to have refused to submit to testing. Nothing in this Section shall be construed to require the delay of necessary medical attention for injured people following an accident or to prohibit a covered employee from leaving the scene of an accident for the period necessary to obtain assistance in responding to the accident or to obtain necessary emergency medical care. [49 CFR 199.225(a)(3)]

2. Reasonable Suspicion Testing [49 CFR 199.225(b)]

a. Each operator shall require a covered employee to submit to an alcohol test when the operator has reasonable suspicion to believe that the employee has violated the prohibitions in this Chapter. [49 CFR 199.225(b)(1)]

b. The operator's determination that reasonable suspicion exists to require the covered employee to undergo an alcohol test shall be based on specific, contemporaneous, articulable observations concerning the appearance, behavior, speech, or body odors of the employee. The required observations shall be made by a supervisor who is trained in detecting the symptoms of alcohol misuse. The supervisor who makes the determination that reasonable suspicion exists shall not conduct the breath alcohol test on that employee. [49 CFR 199.225(b)(2)]

c. Alcohol testing is authorized by this Section only if the observations required by Subparagraph 2.b of this Section are made during, just preceding, or just after the period of the work day that the employee is required to be in compliance with this Chapter. A covered employee may be directed by the operator to undergo reasonable suspicion testing for alcohol only while the employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing covered functions. [49 CFR 199.225(b)(3)]

d.i. If a test required by this Section is not administered within two hours following the determination under Subparagraph 2.b of this Section, the operator shall prepare and maintain on file a record stating the reasons the test was not promptly administered. If a test required by this Section is not administered within eight hours following the determination under Subparagraph 2.b of this Section, the operator shall cease attempts to administer an alcohol test and shall state in the record the reasons for not administering the test. Records shall be submitted to PHMSA upon request of the administrator. [49 CFR 199.225(b)(4)(i)]

ii. Reserved.

iii. Notwithstanding the absence of a reasonable suspicion alcohol test under this Section, an operator shall not permit a covered employee to report for duty or remain on duty requiring the performance of covered functions while the employee is under the influence of or impaired by alcohol, as shown by the behavioral, speech, or performance indicators of alcohol misuse, nor shall an operator permit the covered employee to perform or continue to perform covered functions, until: [49 CFR 199.225(b)(4)(iii)]

(a). an alcohol test is administered and the employee's alcohol concentration measures less than 0.02; or [49 CFR 199.225(b)(4)(iii)(A)]

(b). the start of the employee's next regularly scheduled duty period, but not less than eight hours following the determination under Subparagraph 2.b of this Section that there is reasonable suspicion to believe that the employee has violated the prohibitions in this Chapter. [49 CFR 199.225(b)(4)(iii)(B)]

iv. Except as provided in Clause 2.d.ii, no operator shall take any action under this Chapter against a covered employee based solely on the employee's behavior and appearance in the absence of an alcohol test. This does not prohibit an operator with the authority independent of this Chapter from taking any action otherwise consistent with law. [49 CFR 199.225(b)(4)(iv)]

3. Return-to-Duty Testing. Each operator shall ensure that before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§6515-6523, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02. [49 CFR 199.225(c)]

4. Follow-Up Testing [49 CFR 199.225(d)]

a. Following a determination under §6543 that a covered employee is in need of assistance in resolving problems associated with alcohol misuse, each operator shall ensure that the employee is subject to unannounced follow-up alcohol testing as directed by a substance abuse professional in accordance with the provisions of §6543.C.2.b . [49 CFR 199.225(d)(1)]

b. Follow-up testing shall be conducted when the covered employee is performing covered functions; just before the employee is to perform covered functions; or just after the employee has ceased performing such functions. [49 CFR 199.225(d)(2)]

5. Retesting of Covered Employees with an Alcohol Concentration of 0.02 or Greater but Less Than 0.04. Each operator shall retest a covered employee to ensure compliance with the provisions of §6537, if an operator chooses to permit the employee to perform a covered function within eight hours following the administration of an alcohol test indicating an alcohol concentration of 0.02 or greater but less than 0.04. [49 CFR 199.225(e)]

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§6527. Retention of Records [49 CFR 199.227]

A. General Requirement. Each operator shall maintain records of its alcohol misuse prevention program as provided in this Section. The records shall be maintained in a secure location with controlled access. [49 CFR 199.227(a)]

B. Period of Retention. Each operator shall maintain the records in accordance with the following schedule. [49 CFR 199.227(b)]

1. Five Years. Records of employee alcohol test results with results indicating an alcohol concentration of 0.02 or greater, documentation of refusals to take required alcohol tests, calibration documentation, employee evaluation and referrals, and MIS annual report data shall be maintained for a minimum of five years. [49 CFR 199.227(b)(1)]

2. Two Years. Records related to the collection process (except calibration of evidential breath testing devices), and training shall be maintained for a minimum of two years. [49 CFR 199.227(b)(2)]

3. One Year. Records of all test results below 0.02 (as defined in 49 CFR Part 40) shall be maintained for a minimum of one year. [49 CFR 199.227(b)(3)]

4. Three years. Records of decisions not to administer post- accident employee alcohol tests must be kept for a minimum of three years. [49 CFR 199.227(b)(4)]

C. Types of Records. The following specific records shall be maintained: [49 CFR 199.227(c)]

1. records related to the collection process: [49 CFR 199.227(c)(1)]

a. collection log books, if used; [49 CFR 199.227(c)(1)(i)]

b. calibration documentation for evidential breath testing devices; [49 CFR 199.227(c)(1)(ii)]

c. documentation of breath alcohol technician training; [49 CFR 199.227(c)(1)(iii)]

d. documents generated in connection with decisions to administer reasonable suspicion alcohol tests; [49 CFR 199.227(c)(1)(iv)]

e. documents generated in connection with decisions on post-accident tests; [49 CFR 199.227(c)(1)(v)]

f. documents verifying existence of a medical explanation of the inability of a covered employee to provide adequate breath for testing; [49 CFR 199.227(c)(1)(vi)]

2. records related to test results: [49 CFR 199.227(c)(2)]

a. the operator's copy of the alcohol test form, including the results of the test; [49 CFR 199.227(c)(2)(i)]

b. documents related to the refusal of any covered employee to submit to an alcohol test required by this Chapter; [49 CFR 199.227(c)(2)(ii)]

c. documents presented by a covered employee to dispute the result of an alcohol test administered under this Chapter; [49 CFR 199.227(c)(2)(iii)]

3. records related to other violations of this chapter; [49 CFR 199.227(c)(3)]

4. records related to evaluations: [49 CFR 199.227(c)(4)]

a. records pertaining to a determination by a substance abuse professional concerning a covered employee's need for assistance; [49 CFR 199.227(c)(4)(i)]

b. records concerning a covered employee's compliance with the recommendations of the substance abuse professional; [49 CFR 199.227(c)(4)(ii)]

5. records related to the operator's MIS annual testing data; [49 CFR 199.227(c)(5)]

6. records related to education and training: [49 CFR 199.227(c)(6)]

a. materials on alcohol misuse awareness, including a copy of the operator's policy on alcohol misuse; [49 CFR 199.227(c)(6)(i)]

b. documentation of compliance with the requirements of §3335; [49 CFR 199.227(c)(6)(ii)]

c. documentation of training provided to supervisors for the purpose of qualifying the supervisors to make a determination concerning the need for alcohol testing based on reasonable suspicion; [49 CFR 199.227(c)(6)(iii)]

d. certification that any training conducted under this Chapter complies with the requirements for such training. [49 CFR 199.227(c)(6)(iv)]

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§6529. Reporting of Alcohol Testing Results [49 CFR 199.229]

A. Each large operator (having more than 50 covered employees) must submit an annual MIS report to PHMSA of its alcohol testing results using the MIS form and instructions as required by 49 CFR part 40 (at § 40.26 and appendix H to part 40), not later than March 15 of each year for the prior calendar year (January 1 through December 31). The Administrator may require by notice in the PHMSA Portal (https://portal.phmsa.dot.gov/phmsaportallanding) that small operators (50 or fewer covered employees), not otherwise required to submit annual MIS reports, to prepare and submit such reports to PHMSA. [49 CFR 199.229(a)]

B. Each operator that has a covered employee who performs multi-DOT agency functions (e.g., an employee performs pipeline maintenance duties and drives a commercial motor vehicle), count the employee only on the MIS report for the DOT agency under which he or she is tested. Normally, this will be the DOT agency under which the employee performs more than 50 percent of his or her duties. Operators may have to explain the testing data for these employees in the event of a DOT agency inspection or audit. [49 CFR 199.229(b)]

C. Each report required under this section must be submitted electronically at http://damis.dot.gov. An operator may obtain the user name and password needed for electronic reporting from the PHMSA Portal (https://portal.phmsa.dot.gov/phmsaportallanding). If electronic reporting imposes an undue burden and hardship, the operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE., Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov to make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received. [49 CFR 199.229(c)]

D. A service agent (e.g., Consortia/Third Party Administrator as defined in Part 40) may prepare the MIS report on behalf of an operator. However, each report shall be certified by the operator's anti-drug manager or designated representative for accuracy and completeness. [49 CFR 199.229(d)]

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§6531. Access to Facilities and Records [49 CFR 199.231]

A. Except as required by law or expressly authorized or required in this Chapter, no employer shall release covered employee information that is contained in records required to be maintained in §6527. [49 CFR 199.231(a)]

B. A covered employee is entitled, upon written request, to obtain copies of any records pertaining to the employee's use of alcohol, including any records pertaining to his or her alcohol tests. The operator shall promptly provide the records requested by the employee. Access to a employee's records shall not be contingent upon payment for records other than those specifically requested. [49 CFR 199.231(b)]

C. Each operator shall permit access to all facilities utilized in complying with the requirements of this Chapter to the secretary of transportation, any DOT agency, or a representative of a state agency with regulatory authority over the operator. [49 CFR 199.231(c)]

D. Each operator shall make available copies of all results for employer alcohol testing conducted under this Chapter and any other information pertaining to the operator's alcohol misuse prevention program, when requested by the secretary of transportation, any DOT agency with regulatory authority over the operator, or a representative of a state agency with regulatory authority over the operator. The information shall include name-specific alcohol test results, records, and reports. [49 CFR 199.231(d)]

E. When requested by the National Transportation Safety Board as part of an accident investigation, an operator shall disclose information related to the operator's administration of any post-accident alcohol tests administered following the accident under investigation. [49 CFR 199.231(e)]

F. An operator shall make records available to a subsequent employer upon receipt of the written request from the covered employee. Disclosure by the subsequent employer is permitted only as expressly authorized by the terms of the employee's written request. [49 CFR 199.231(f)]

G. An operator may disclose information without employee consent as provided by DOT procedures concerning certain legal proceedings. [49 CFR 199.231(g)]

H. An operator shall release information regarding a covered employee's records as directed by the specific, written consent of the employee authorizing release of the information to an identified person. Release of such information by the person receiving the information is permitted only in accordance with the terms of the employee's consent. [49 CFR 199.231(h)]

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§6533. Removal from Covered Function [49 CFR 199.233]

A. Except as provided in §§6539-6543, no operator shall permit any covered employee to perform covered functions if the employee has engaged in conduct prohibited by §§6515 through 6523 or an alcohol misuse rule of another DOT agency. [49 CFR 199.233]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:834 (August 1995), amended LR 30:1301 (June 2004).

§6535. Required Evaluation and Testing [49 CFR 199.235]

A. No operator shall permit a covered employee who has engaged in conduct prohibited by §§6515-6523 to perform covered functions unless the employee has met the requirements of §6543. [49 CFR 199.235]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:834 (August 1995), amended LR 30:1301 (June 2004).

§6537. Other Alcohol-Related Conduct [49 CFR 199.237]

A. No operator shall permit a covered employee tested under the provisions of §6525, who is found to have an alcohol concentration of 0.02 or greater but less than 0.04, to perform or continue to perform covered functions, until: [49 CFR 199.237(a)]

1. the employee's alcohol concentration measures less than 0.02 in accordance with a test administered under §6525.A.5; or [49 CFR 199.237(a)(1)]

2. the start of the employee's next regularly scheduled duty period, but not less than eight hours following administration of the test. [49 CFR 199.237(a)(2)]

B. Except as provided in Subsection A of this Section, no operator shall take any action under this Chapter against an employee based solely on test results showing an alcohol concentration less than 0.04. This does not prohibit an operator with authority independent of this Chapter from taking any action otherwise consistent with law. [49 CFR 199.237(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

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§6539. Operator Obligation to Promulgate a Policy on the Misuse of Alcohol [49 CFR 199.239]

A. General Requirements. Each operator shall provide educational materials that explain these alcohol misuse requirements and the operator's policies and procedures with respect to meeting those requirements. [49 CFR 199.239(a)]

1. The operator shall ensure that a copy of these materials is distributed to each covered employee prior to start of alcohol testing under this Chapter, and to each person subsequently hired for or transferred to a covered position. [49 CFR 199.239(a)(1)]

2. Each operator shall provide written notice to representatives of employee organizations of the availability of this information. [49 CFR 199.239(a)(2)]

B. Required Content. The materials to be made available to covered employees shall include detailed discussion of at least the following: [49 CFR 199.239(b)]

1. the identity of the person designated by the operator to answer covered employee questions about the materials; [49 CFR 199.239(b)(1)]

2. the categories of employees who are subject to the provisions of this Chapter; [49 CFR 199.239(b)(2)]

3. sufficient information about the covered functions performed by those employees to make clear what period of the work day the covered employee is required to be in compliance with this Chapter; [49 CFR 199.239(b)(3)]

4. specific information concerning covered employee conduct that is prohibited by this Chapter; [49 CFR 199.239(b)(4)]

5. the circumstances under which a covered employee will be tested for alcohol under this Chapter; [49 CFR 199.239(b)(5)]

6. the procedures that will be used to test for the presence of alcohol, protect the covered employee and the integrity of the breath testing process, safeguard the validity of the test results, and ensure that those results are attributed to the correct employee; [49 CFR 199.239(b)(6)]

7. the requirement that a covered employee submit to alcohol tests administered in accordance with this Chapter; [49 CFR 199.239(b)(7)]

8. an explanation of what constitutes a refusal to submit to an alcohol test and the attendant consequences; [49 CFR 199.239(b)(8)]

9. the consequences for covered employees found to have violated the prohibitions under this Chapter, including the requirement that the employee be removed immediately from covered functions, and the procedures under §6543; [49 CFR 199.239(b)(9)]

10. the consequences for covered employees found to have an alcohol concentration of 0.02 or greater but less than 0.04; [49 CFR 199.239(b)(10)]

11. information concerning the effects of alcohol misuse on an individual's health, work, and personal life; signs and symptoms of an alcohol problem (the employee's or a coworker's); and including intervening evaluating and resolving problems associated with the misuse of alcohol including intervening when an alcohol problem is suspected, confrontation, referral to any available EAP, and/or referral to management. [49 CFR 199.239(b)(11)]

C. Optional Provisions. The materials supplied to covered employees may also include information on additional operator policies with respect to the use or possession of alcohol, including any consequences for an employee found to have a specified alcohol level, that are based on the operator's authority independent of this Chapter. Any such additional policies or consequences shall be clearly described as being based on independent authority. [49 CFR 199.239(c)]

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§6541. Training for Supervisors [49 CFR 199.241]

A. Each operator shall ensure that persons designated to determine whether reasonable suspicion exists to require a covered employee to undergo alcohol testing under §6525.A.2 receive at least 60 minutes of training on the physical, behavioral, speech, and performance indicators of probable alcohol misuse. [49 CFR 199.241]

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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:834 (August 1995), amended LR 30:1302 (June 2004).

§6543. Referral, Evaluation, and Treatment [49 CFR 199.243]

A. Each covered employee who has engaged in conduct prohibited by §§6515-6523 of this Chapter shall be advised of the resources available to the covered employee in evaluating and resolving problems associated with the misuse of alcohol, including the names, addresses, and telephone numbers of substance abuse professionals and counseling and treatment programs. [49 CFR 199.243(a)]

B. Each covered employee who engages in conduct prohibited under §§6515-6523 shall be evaluated by a substance abuse professional who shall determine what assistance, if any, the employee needs in resolving problems associated with alcohol misuse. [49 CFR 199.243(b)]

C.1. Before a covered employee returns to duty requiring the performance of a covered function after engaging in conduct prohibited by §§6515-6523 of this Chapter, the employee shall undergo a return-to-duty alcohol test with a result indicating an alcohol concentration of less than 0.02. [49 CFR 199.243(c)(1)]

2. In addition, each covered employee identified as needing assistance in resolving problems associated with alcohol misuse: [49 CFR 199.243(c)(2)]

a. shall be evaluated by a substance abuse professional to determine that the employee has properly followed any rehabilitation program prescribed under Subsection B of this Section, and [49 CFR 199.243(c)(2)(i)]

b. shall be subject to unannounced follow-up alcohol tests administered by the operator following the employee's return to duty. The number and frequency of such follow-up testing shall be determined by a substance abuse professional, but shall consist of at least six tests in the first 12 months following the employee's return to duty. In addition, follow-up testing may include testing for drugs, as directed by the substance abuse professional, to be performed in accordance with 49 CFR Part 40. Follow-up testing shall not exceed 60 months from the date of the employee's return to duty. The substance abuse professional may terminate the requirement for follow-up testing at any time after the first six tests have been administered, if the substance abuse professional determines that such testing is no longer necessary. [49 CFR 199.243(c)(2)(ii)]

D. Evaluation and rehabilitation may be provided by the operator, by a substance abuse professional under contract with the operator, or by a substance abuse professional not affiliated with the operator. The choice of substance abuse professional and assignment of costs shall be made in accordance with the operator/employee agreements and operator/employee policies. [49 CFR 199.243(d)]

E. The operator shall ensure that a substance abuse professional who determines that a covered employee requires assistance in resolving problems with alcohol misuse does not refer the employee to the substance abuse professional's private practice or to a person or organization from which the substance abuse professional receives remuneration or in which the substance abuse professional has a financial interest. This Subsection does not prohibit a substance abuse professional from referring an employee for assistance provided through: [49 CFR 199.243(e)]

1. a public agency, such as a state, county, or municipality; [49 CFR 199.243(e)(1)]

2. the operator or a person under contract to provide treatment for alcohol problems on behalf of the operator; [49 CFR 199.243(e)(2)]

3. the sole source of therapeutically appropriate treatment under the employee's health insurance program; or [49 CFR 199.243(e)(3)]

4. the sole source of therapeutically appropriate treatment reasonably accessible to the employee. [49 CFR 199.243(e)(4)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:835 (August 1995), amended LR 30:1302 (June 2004).

§6545. Contractor Employees [49 CFR 199.245]

A. With respect to those covered employees who are contractors or employed by a contractor, an operator may provide by contract that the alcohol testing, training and education required by this Chapter be carried out by the contractor provided: [49 CFR 199.245(a)]

1. the operator remains responsible for ensuring that the requirements of this Chapter and 49 CFR Part 40 are complied with; and [49 CFR 199.245(b)]

2. the contractor allows access to property and records by the operator, the administrator, any DOT agency with regulatory authority over the operator or covered employee, and, if the operator is subject to the jurisdiction of a state agency, a representative of the state agency for the purposes of monitoring the operator's compliance with the requirements of this Chapter and 49 CFR Part 40. [49 CFR 199.245(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:751-757, redesignated as R.S. 30:701-707 and R.S. 30:501 et seq.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 21:835 (August 1995), amended LR 30:1302 (June 2004).

Subpart 5. Liquefied Natural Gas Facilities: Federal Safety Standards

Chapter 67. General [49 CFR Part 193—Subpart A]

§6701. Scope of Part [49 CFR 193.2001]

A. This part prescribes safety standards for LNG facilities used in the transportation of gas by pipeline that is subject to the pipeline safety laws (49 U.S.C. 60101 et seq.) and LAC 43:XIII.Subpart 3. [49 CFR 193.2001(a)]

B. This part does not apply to:

1. LNG facilities used by ultimate consumers of LNG or natural gas; [49 CFR 193.2001(b)(1)]

2. LNG facilities used in the course of natural gas treatment or hydrocarbon extraction which do not store LNG; [49 CFR 193.2001(b)(2)]

3. in the case of a marine cargo transfer system and associated facilities, any matter other than siting pertaining to the system or facilities between the marine vessel and the last manifold (or in the absence of a manifold, the last valve) located immediately before a storage tank; [49 CFR 193.2001(b)(3)]

4. any LNG facility located in navigable waters (as defined in Section 3(8) of the Federal Power Act [16 U.S.C. 796(8)]. [49 CFR 193.2001(b)(4)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1047 (June 2018).

§6705. Applicability [49 CFR 193.2005]

A. Regulations in this part governing siting, design, installation, or construction of LNG facilities (including material incorporated by reference in these regulations) do not apply to LNG facilities in existence or under construction when the regulations go into effect. [49 CFR 193.2005(a)]

B. If an existing LNG facility (or facility under construction before March 31, 2000 is replaced, relocated or significantly altered after March 31, 2000, the facility must comply with the applicable requirements of this part governing, siting, design, installation, and construction, except that:

1. the siting requirements apply only to LNG storage tanks that are significantly altered by increasing the original storage capacity or relocated; and [49 CFR 193.2005(b)(1)]

2. to the extent compliance with the design, installation, and construction requirements would make the replaced, relocated, or altered facility incompatible with the other facilities or would otherwise be impractical, the replaced, relocated, or significantly altered facility may be designed, installed, or constructed in accordance with the original specifications for the facility, or in another manner subject to the approval of the commissioner. [49 CFR 193.2005(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1047 (June 2018).

§6707. Definitions [49 CFR 193.2007]

A. As used in this part: [49 CFR 193.2007]

Commissioner—the commissioner of conservation or any person to whom he has delegated authority in the matter concerned.

Ambient Vaporizer—a vaporizer which derives heat from naturally occurring heat sources, such as the atmosphere, sea water, surface waters, or geothermal waters.

Cargo Transfer System—a component, or system of components functioning as a unit, used exclusively for transferring hazardous fluids in bulk between a tank car, tank truck, or marine vessel and a storage tank.

Component—any part, or system of parts functioning as a unit, including, but not limited to, piping, processing equipment, containers, control devices, impounding systems, lighting, security devices, fire control equipment, and communication equipment, whose integrity or reliability is necessary to maintain safety in controlling, processing, or containing a hazardous fluid.

Container—a component other than piping that contains a hazardous fluid.

Control System—a component, or system of components functioning as a unit, including control valves and sensing, warning, relief, shutdown, and other control devices, which is activated either manually or automatically to establish or maintain the performance of another component.

Controllable Emergency—an emergency where reasonable and prudent action can prevent harm to people or property.

Design Pressure—the pressure used in the design of components for the purpose of determining the minimum permissible thickness or physical characteristics of its various parts. When applicable, static head shall be included in the design pressure to determine the thickness of any specific part.

Determine—make an appropriate investigation using scientific methods, reach a decision based on sound engineering judgment, and be able to demonstrate the basis of the decision.

Dike—the perimeter of an impounding space forming a barrier to prevent liquid from flowing in an unintended direction.

Emergency—a deviation from normal operation, a structural failure, or severe environmental conditions that probably would cause harm to people or property.

Exclusion Zone—an area surrounding an LNG facility in which an operator or government agency legally controls all activities in accordance with LAC 43:XIII.6957 and LAC 43:XIII.6959 for as long as the facility is in operation.

Fail-Safe—a design feature which will maintain or result in a safe condition in the event of malfunction or failure of a power supply, component, or control device.

g—the standard acceleration of gravity of 9.806 meters per second^2 (32.17 feet per second^2).

Gas—except when designated as inert, means natural gas, other flammable gas, or gas which is toxic or corrosive.

Hazardous Fluid—gas or hazardous liquid.

Hazardous Liquid—LNG or a liquid that is flammable or toxic.

Heated Vaporizer—a vaporizer which derives heat from other than naturally occurring heat sources.

Impounding Space—a volume of space formed by dikes and floors which is designed to confine a spill of hazardous liquid.

Impounding System—includes an impounding space, including dikes and floors for conducting the flow of spilled hazardous liquids to an impounding space.

Liquefied Natural Gas or *LNG*—natural gas or synthetic gas having methane (CH_4) as its major constituent which has been changed to a liquid.

LNG Facility—a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas.

LNG Plant—an LNG facility or system of LNG facilities functioning as a unit.

m^3—a volumetric unit which is one cubic meter, 6.2898 barrels, 35.3147 $ft.^3$, or 264.1720 U.S. gallons, each volume being considered as equal to the other.

Maximum Allowable Working Pressure—the maximum gage pressure permissible at the top of the equipment, containers or pressure vessels while operating at design temperature.

Normal Operation—functioning within ranges of pressure, temperature, flow, or other operating criteria required by this part.

Operator—a person who owns or operates an LNG facility.

Person—any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association and includes any trustee, receiver, assignee, or personal representative thereof.

Pipeline Facility—new and existing piping, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

Piping—pipe, tubing, hoses, fittings, valves, pumps, connections, safety devices or related components for containing the flow of hazardous fluids.

Storage Tank—a container for storing a hazardous fluid.

Transfer Piping—a system of permanent and temporary piping used for transferring hazardous fluids between any of the following: Liquefaction process facilities, storage tanks, vaporizers, compressors, cargo transfer systems, and facilities other than pipeline facilities.

Transfer System—includes transfer piping and cargo transfer system.

Vaporization—an addition of thermal energy changing a liquid to a vapor or gaseous state.

Vaporizer—a heat transfer facility designed to introduce thermal energy in a controlled manner for changing a liquid to a vapor or gaseous state.

Waterfront LNG Plant—an LNG plant with docks, wharves, piers, or other structures in, on, or immediately adjacent to the navigable waters of the United States or Puerto Rico and any shore area immediately adjacent to those waters to which vessels may be secured and at which LNG cargo operations may be conducted.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1047 (June 2018).

§6709. Rules of Regulatory Construction [49 CFR 193.2009]

A. As used in this Part:

Includes—including but not limited to; [49CFR 193.2009(a)(1)]

May—is permitted to or is authorized to; [49 CFR 193.2009(a)(2)]

May Not—is not permitted to or is not authorized to; and [49 CFR 193.2009(a)(3)]

Shall or Must—used in the mandatory and imperative sense. [49 CFR 193.2009(a)(4)].

B. In this Part:

1. words importing the singular include the plural; and [49 CFR 193.2009(b)(1)]

2. words importing the plural include the singular. [49 CFR 193.2009(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1048 (June 2018).

§6711. Reporting [49 CFR 193.2011]

A. Incidents, safety-related conditions, and annual pipeline summary data for LNG plants or facilities must be reported in accordance with requirements of Chapter 3 of Subpart 2. [75 FR 72906, Nov. 26, 2010] [49 CFR 193.2011]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1048 (June 2018).

§6713. What documents are incorporated by reference partly or wholly in this part? [49 CFR 193.2013]

A. This Part prescribes standards, or portions thereof, incorporated by reference into this part with the approval of the Director of the *Federal Register* in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the *Federal Register*. [49 CFR 193.2013(a)]

1. Availability of standards incorporated by reference. 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. [49 CFR 193.2013(a)(1)(i)]

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*;* [49 CFR 193.2013(a)(1)(ii)]

c. copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below; [49 CFR 193.2013(a)(1)(iii)]

2. American Gas Association (AGA), 400 North Capitol Street NW., Washington, DC 20001, and phone: 202-824-7000, Web site: http://www.aga.org/; [49 CFR 193.2013(b)]

a. American Gas Association, "Purging Principles and Practices," 3rd edition, June 2001, (Purging Principles and Practices), IBR approved for §§7713.B and 7713.C, 7717, and 7715.A; [49 CFR 193.2013(b)(1)]

b. [Reserved] [49 CFR 193.2013(b)(2)]

3. American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, and phone: 202-682-8000, Web site: http://api.org/; [49 CFR 193.2013(c)]

a. API Standard 620, "Design and Construction of Large, Welded, Low-pressure Storage Tanks," 11th edition, February 2008 [including addendum 1 (March 2009), addendum 2 (August 2010), and addendum 3 (March 2012)], (API Std 620), IBR approved for §§7101.B; 7321.B; [49 CFR 193.2013(c)(1)]

b. [Reserved]; [49 CFR 193.2013(c)(2)]

4. American Society of Civil Engineers (ASCE), 1801 Alexander Bell Drive, Reston, VA 20191, (800) 548-2723, 703 295-6300 (international), Web site: http://www.asce.org; [49 CFR 193.2013(d)]

a. ASCE/SEI 7-05, "Minimum Design Loads for Buildings and Other Structures" 2005 edition (including supplement No. 1 and Errata), (ASCE/SEI 7-05), IBR approved for §6967.B; [49 CFR 193.2013(d)(1)]

b. [Reserved]; [49 CFR 193.2013(d)(2)]

5. ASME International (ASME), Three Park Avenue, New York, NY 10016. 800-843-2763 (U.S/Canada), Web site:http://www.asme.org/; [49 CFR 193.2013(e)]

a. ASME Boiler and Pressure Vessel Code, Section VIII, Division 1: "Rules for Construction of Pressure Vessels," 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1), IBR approved for §7321.A; [49 CFR 193.2013(e)(1)]

b. [Reserved]; [49 CFR 193.2013(e)(2)]

6. Gas Technology Institute (GTI), formerly the Gas Research Institute (GRI), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847-768-0500, Web site: www.gastechnology.org; [49 CFR 193.2013(f)]

a. GRI-96/0396.5, "Evaluation of Mitigation Methods for Accidental LNG Releases, Volume 5: Using FEM3A for LNG Accident Consequence Analyses," April 1997, (GRI-96/0396.5), IBR approved for §6959.A; [49 CFR 193.2013(f)(1)]

b. GTI-04/0032 LNGFIRE3: "A Thermal Radiation Model for LNG Fires" March 2004, (GTI-04/0032 LNGFIRE3), IBR approved for §6957.A; [49 CFR 193.2013(f)(2)]

c. GTI-04/0049 "LNG Vapor Dispersion Prediction with the DEGADIS 2.1: Dense Gas Dispersion Model for LNG Vapor Dispersion," April 2004, (GTI-04/0049), IBR approved for §6959.A; [49 CFR 193.2013(f)(3)]

7. National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, MA, 02169 phone: 617-984-7275, Web site: http://www.nfpa.org/; [49 CFR 193.2013(g)]

a. NFPA-59A (2001), "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)," (NFPA-59A-2001), IBR approved for §§6719.A, 6951, 6957, 6959 introductory text and 6959.C, 7101.A, 7301, 7303, 7501, 7721, 7939.A, and 8301; [49 CFR 193.2013(g)(1)]

b. NFPA 59A (2006), "Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)," 2006 edition, approved August 18, 2005, (NFPA-59A-2006), IBR approved for §§7101.B and 7321.B. [49 CFR 193.2013(g)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1048 (June 2018).

§6717. Plans and Procedures [49 CFR 193.2017]

A. Each operator shall maintain at each LNG plant the plans and procedures required for that plant by this part. The plans and procedures must be available upon request for review and inspection by the commissioner. In addition, each change to the plans or procedures must be available at the LNG plant for review and inspection within 20 days after the change is made. [49 CFR 193.2017(a)]

B. The associate administrator or the state agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant state procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety. [49 CFR 192.603(c)]

C. Each operator must review and update the plans and procedures required by this part:

1. when a component is changed significantly or a new component is installed; and [49 CFR 193.2017(c)(1)]

2. at intervals not exceeding 27 months, but at least once every two calendar years. [49 CFR 193.2017(c)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1049 (June 2018).

§6719. Mobile and Temporary LNG Facilities [49 CFR 193.2019]

A. Mobile and temporary LNG facilities for peakshaving application, for service maintenance during gas pipeline systems repair/alteration, or for other short term applications need not meet the requirements of this part if the facilities are in compliance with applicable sections of NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713). [49 CFR 193.2019(a)]

B. The commissioner must be provided with a location description for the installation at least two weeks in advance, including to the extent practical, the details of siting, leakage containment or control, firefighting equipment, and methods employed to restrict public access, except that in the case of emergency where such notice is not possible, as much advance notice as possible must be provided.

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1049 (June 2018).

Chapter 69. Siting Requirements [49 CFR Part 193 Subpart B]

§6951. Scope [49 CFR 193.2051]

A. Each LNG facility designed, constructed, replaced, relocated or significantly altered after March 31, 2000 must be provided with siting requirements in accordance with the requirements of this part and of NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713). In the event of a conflict between this part and NFPA-59A-2001, this part prevails. [49 CFR 193.2051]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1050 (June 2018).

§6957. Thermal Radiation Protection [49 CFR 193.2057]

A. Each LNG container and LNG transfer system must have a thermal exclusion zone in accordance with section 2.2.3.2 of NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713) with the following exceptions.

1. The thermal radiation distances must be calculated using Gas Technology Institute's (GTI) report or computer model GTI-04/0032 LNGFIRE3: A Thermal Radiation Model for LNG Fires (incorporated by reference, see LAC 43:XIII.6713). The use of other alternate models which take into account the same physical factors and have been validated by experimental test data may be permitted subject to the Commissioner's approval. [49 CFR 193.2057(a)]

2. In calculating exclusion distances, the wind speed producing the maximum exclusion distances shall be used except for wind speeds that occur less than 5 percent of the time based on recorded data for the area. [49 CFR 193.2057(b)]

3. In calculating exclusion distances, the ambient temperature and relative humidity that produce the maximum exclusion distances shall be used except for values that occur less than five percent of the time based on recorded data for the area. [49 CFR 193.2057(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1050 (June 2018).

§6959. Flammable Vapor-Gas Dispersion Protection [49 CFR 193.2059]

A. Each LNG container and LNG transfer system must have a dispersion exclusion zone in accordance with sections 2.2.3.3 and 2.2.3.4 of NFPA-59A-2001 (incorporated by reference, see §6713) with the following exceptions.

1. Flammable vapor-gas dispersion distances must be determined in accordance with the model described in the GTI-04/0049, "LNG Vapor Dispersion Prediction with the DEGADIS 2.1 Dense Gas Dispersion Model" (incorporated by reference, see §6713). Alternatively, in order to account for additional cloud dilution which may be caused by the complex flow patterns induced by tank and dike structure, dispersion distances may be calculated in accordance with the model described in the Gas Research Institute report GRI-96/0396.5 (incorporated by reference, see §6713), "Evaluation of Mitigation Methods for Accidental LNG Releases. Volume 5: Using FEM3A for LNG Accident Consequence Analyses". The use of alternate models which take into account the same physical factors and have been validated by experimental test data shall be permitted, subject to the Commissioner's approval. [49 CFR 193.2059(a)]

2. The following dispersion parameters must be used in computing dispersion distances.

a. Average gas concentration in air = 2.5 percent. [49 CFR 193.2059(b)(1)]

b. Dispersion conditions are a combination of those which result in longer predicted downwind dispersion distances than other weather conditions at the site at least 90 percent of the time, based on figures maintained by National Weather Service of the U.S. Department of Commerce, or as an alternative where the model used gives longer distances at lower wind speeds, Atmospheric Stability (Pasquill Class) F, wind speed = 4.5 miles per hour (2.01 meters/sec) at reference height of 10 meters, relative humidity = 50.0 percent, and atmospheric temperature = average in the region. [49 CFR 193.2059(b)(2)]

c. The elevation for contour (receptor) output H = 0.5 meters. [49 CFR 193.2059(b)(3)]

d. A surface roughness factor of 0.03 meters shall be used. Higher values for the roughness factor may be used if it can be shown that the terrain both upwind and downwind of the vapor cloud has dense vegetation and that the vapor cloud height is more than ten times the height of the obstacles encountered by the vapor cloud. [49 CFR 193.2059(b)(4)]

3. The design spill shall be determined in accordance with section 2.2.3.5 of NFPA-59A-2001 (incorporated by reference, see §6713). [49 CFR 193.2059(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1050 (June 2018).

§6967. Wind Forces [49 CFR 193.2067]

A. LNG facilities must be designed to withstand without loss of structural or functional integrity:

1. the direct effect of wind forces; [49 CFR 193.2067(a)(1)]

2. the pressure differential between the interior and exterior of a confining, or partially confining, structure; and [49 CFR 193.2067(a)(2)]

3. in the case of impounding systems for LNG storage tanks, impact forces and potential penetrations by wind borne missiles. [49 CFR 193.2067(a)(3)]

B. The wind forces at the location of the specific facility must be based on one of the following:

1. for shop fabricated containers of LNG or other hazardous fluids with a capacity of not more than 70,000 gallons, applicable wind load data in ASCE/SEI 7 (incorporated by reference, see §6713). [49 CFR 193.2067(b)(1)]

2. for all other LNG facilities:

a. an assumed sustained wind velocity of not less than 150 miles per hour, unless the Commissioner finds a lower velocity is justified by adequate supportive data; or [49 CFR 193.2067(b)(2)(i)]

b. the most critical combination of wind velocity and duration, with respect to the effect on the structure, having a probability of exceedance in a 50-year period of 0.5 percent or less, if adequate wind data are available and the probabilistic methodology is reliable. [49 CFR 193.2067(b)(2)(ii)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1050 (June 2018).

Chapter 71. Design [49 CFR Part 193 Subpart C]

§7101. Scope [49 CFR 193.2101]

A. Each LNG facility designed after March 31, 2000 must comply with the requirements of this part and of NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713). If there is a conflict between this Part and NFPA-59A-2001, the requirements in this part prevail. [49 CFR 193.2101(a)]

B. Each stationary LNG storage tank must comply with Section 7.2.2 of NFPA-59A-2006 (incorporated by reference, see LAC 43:XIII.6713) for seismic design of field fabricated tanks. All other LNG storage tanks must comply with API Std-620 (incorporated by reference, see LAC 43:XIII.6713) for seismic design. [49 CFR 193.2101(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1051 (June 2018).

§7119. Records [49 CFR 193.2119]

A. Each operator shall keep a record of all materials for components, buildings, foundations, and support systems, as necessary to verify that material properties meet the requirements of this part. These records must be maintained for the life of the item concerned. [49 CFR 193.2119]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1051 (June 2018).

§7155. Structural Requirements [49 CFR 193.2155]

A. The structural members of an impoundment system must be designed and constructed to prevent impairment of the system's performance reliability and structural integrity as a result of the following:

1. the imposed loading from:

a. full hydrostatic head of impounded LNG; [49 CFR 193.2155(a)(1)(i)]

b. hydrodynamic action, including the effect of any material injected into the system for spill control; [49 CFR 193.2155(a)(1)(ii)]

c. the impingement of the trajectory of an LNG jet discharged at any predictable angle; and [49 CFR 193.2155(a)(1)(iii)]

d. anticipated hydraulic forces from a credible opening in the component or item served, assuming that the discharge pressure equals design pressure; [49 CFR 193.2155(a)(1)(iv)]

2. the erosive action from a spill, including jetting of spilling LNG, and any other anticipated erosive action including surface water runoff, ice formation, dislodgement of ice formation, and snow removal; [49 CFR 193.2155(a)(2)]

3. the effect of the temperature, any thermal gradient, and any other anticipated degradation resulting from sudden or localized contact with LNG; [49 CFR 193.2155(a)(3)]

4. exposure to fire from impounded LNG or from sources other than impounded LNG; [49 CFR 193.2155(a)(4)]

5. if applicable, the potential impact and loading on the dike due to:

a. of the component or item served or adjacent components; and [49 CFR 193.2155(a)(5)(i)]

b. the LNG facility adjoins the right-of-way of any highway or railroad, collision by or explosion of a train, tank car, or tank truck that could reasonably be expected to cause the most severe loading. [49 CFR 193.2155(a)(b)(ii)]

B. An LNG storage tank must not be located within a horizontal distance of one mile (1.6 km) from the ends, or 1/4 mile (0.4 km) from the nearest point of a runway, whichever is longer. The height of LNG structures in the vicinity of an airport must also comply with Federal Aviation Administration requirements in 14 CFR Section 1.1. [49 CFR 193.2155(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1051 (June 2018).

§7161. Dikes, General [49 CFR 193.2161]

A. An outer wall of a component served by an impounding system may not be used as a dike unless the outer wall is constructed of concrete. [49 CFR 193.2161]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1051 (June 2018).

§7167. Covered Systems [49 CFR 193.2167]

A. A covered impounding system is prohibited except for concrete wall designed tanks where the concrete wall is an outer wall serving as a dike. [49 CFR 193.2167]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1051 (June 2018).

§7173. Water Removal [193.2173]

A. Impoundment areas must be constructed such that all areas drain completely to prevent water collection. Drainage pumps and piping must be provided to remove water from collecting in the impoundment area. Alternative means of draining may be acceptable subject to the commissioner's approval. [49 CFR 193.2173(a)]

B. The water removal system must have adequate capacity to remove water at a rate equal to 25 percent of the maximum predictable collection rate from a storm of 10-year frequency and 1-hour duration, and other natural causes. For rainfall amounts, operators must use the “Rainfall Frequency Atlas of the United States” published by the National Weather Service of the U.S. Department of Commerce. [49 CFR 193.2173(b)]

C. Sump pumps for water removal must:

1. be operated as necessary to keep the impounding space as dry as practical; and [49 CFR 193.2173(c)(1)]

2. if sump pumps are designed for automatic operation, have redundant automatic shutdown controls to prevent operation when LNG is present. [49 CFR 193.2173(c)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1051 (June 2018).

§7181. Impoundment Capacity: LNG Storage Tanks [49 CFR 193.2181]

A. Each impounding system serving an LNG storage tank must have a minimum volumetric liquid impoundment capacity of:

1. 110 percent of the LNG tank's maximum liquid capacity for an impoundment serving a single tank; [49 CFR 193.2181(a)]

2. 100 percent of all tanks or 110 percent of the largest tank's maximum liquid capacity, whichever is greater, for the impoundment serving more than one tank; or [49 CFR 193.2181(b)]

3. if the dike is designed to account for a surge in the event of catastrophic failure, then the impoundment capacity may be reduced to 100 percent in lieu of 110 percent. [49 CFR 193.2181(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1052 (June 2018).

§7187. Nonmetallic Membrane Liner [49 CFR 193.2187]

A. A flammable nonmetallic membrane liner may not be used as an inner container in a storage tank [49 CFR 193.2187]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1052 (June 2018).

Chapter 73. Construction [49 CFR Part 193 Subpart D]

§7301. Scope [49 CFR 193.2301]

A. Each LNG facility constructed after March 31, 2000 must comply with requirements of this part and of NFPA-59A-2001 (incorporated by reference see LAC 43:XIII.6713). In the event of a conflict between this part and NFPA-59A-2001, this part prevails. [49 CFR 193.2301]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1052 (June 2018).

§7303. Construction Acceptance [49 CFR 193.2303]

A. No person may place in service any component until it passes all applicable inspections and tests prescribed by this subpart and NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713). [49 CFR 193.2303]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1052 (June 2018).

§7304. Corrosion Control Overview [49 CFR 193.2304]

A. Subject to Subparagraph B of this Section, components may not be constructed, repaired, replaced, or significantly altered until a person qualified under LAC 43:XIII.8107(c) reviews the applicable design drawings and materials specifications from a corrosion control viewpoint and determines that the materials involved will not impair the safety or reliability of the component or any associated components. [49 CFR 193.2304(a)]

B. The repair, replacement, or significant alteration of components must be reviewed only if the action to be taken:

1. involves a change in the original materials specified; [49 CFR 193.2304(b)(1)]

2. is due to a failure caused by corrosion; or [49 CFR 193.2304(b)(2)]

3. is occasioned by inspection revealing a significant deterioration of the component due to corrosion. [49 CFR 193.2304(b)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1052 (June 2018).

§7321. Nondestructive Tests [49 CFR 193.2321]

A. The butt welds in metal shells of storage tanks with internal design pressure above 15 psig must be nondestructively examined in accordance with the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see LAC 43:XIII.6713), except that 100 percent of welds that are both longitudinal (or meridional) and circumferential (or latitudinal) of hydraulic load bearing shells with curved surfaces that are subject to cryogenic temperatures must be nondestructively examined in accordance with the ASME BPVC (Section VIII, Division 1). [49 CFR 193.2321(a)]

B. For storage tanks with internal design pressures at 15 psig or less, ultrasonic examinations of welds on metal containers must comply with the following:

1. section 7.3.1.2 of NFPA Std-59A-2006, (incorporated by reference, see LAC 43:XIII.6713); [49 CFR 193.2321(b)(1)]

2. appendices C and Q of API Std 620, (incorporated by reference, see LAC 43:XIII.6713); [49 CFR 193.2321(b)(2)]

C. Ultrasonic examination records must be retained for the life of the facility. If electronic records are kept, they must be retained in a manner so that they cannot be altered by any means; and [49 CFR 193.2321(c)]

D. The ultrasonic equipment used in the examination of welds must be calibrated at a frequency no longer than eight hours. Such calibrations must verify the examination of welds against a calibration standard. If the ultrasonic equipment is found to be out of calibration, all previous weld inspections that are suspect must be reexamined. [49 CFR 193.2321(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1052 (June 2018).

Chapter 75. Equipment [49 CFR Part 193 Subpart E]

§7501. Scope [49 CFR 193.2401]

A. After March 31, 2000, each new, replaced, relocated or significantly altered vaporization equipment, liquefaction equipment, and control systems must be designed, fabricated, and installed in accordance with requirements of this part and of NFPA-59A-2001. In the event of a conflict between this part and NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713), this part prevails. [49 CFR 193.2401]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1053 (June 2018).

§7541. Control Center [49 CFR 193.2441]

A. Each LNG plant must have a control center from which operations and warning devices are monitored as required by this part. A control center must have the following capabilities and characteristics.

1. It must be located apart or protected from other LNG facilities so that it is operational during a controllable emergency. [49 CFR 193.2441(a)]

2. Each remotely actuated control system and each automatic shutdown control system required by this part must be operable from the control center. [49 CFR 193.2441(b)]

3. Each control center must have personnel in continuous attendance while any of the components under its control are in operation, unless the control is being performed from another control center which has personnel in continuous attendance. [49 CFR 193.2441(c)]

4. If more than one control center is located at an LNG Plant, each control center must have more than one means of communication with each other center. [49 CFR 193.2441(d)]

5. Each control center must have a means of communicating a warning of hazardous conditions to other locations within the plant frequented by personnel. [49 CFR 193.2441(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1053 (June 2018).

§7545. Sources of Power [49 CFR 193.2445]

A. Electrical control systems, means of communication, emergency lighting, and firefighting systems must have at least two sources of power which function so that failure of one source does not affect the capability of the other source. [49 CFR 193.2445(a)]

B. Where auxiliary generators are used as a second source of electrical power:

1. they must be located apart or protected from components so that they are not unusable during a controllable emergency; and [49 CFR 193.2445(b)(1)]

2. fuel supply must be protected from hazards. [49 CFR 193.2445(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1053 (June 2018).

Chapter 77. Operations [49 CFR Part 193 Subpart F]

§7701. Scope [49 CFR 193.2501]

A. This subpart prescribes requirements for the operation of LNG facilities. [49 CFR 193.2501]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1053 (June 2018).

§7703. Operating Procedures [49 CFR 193.2503]

A. Each operator shall follow one or more manuals of written procedures to provide safety in normal operation and in responding to an abnormal operation that would affect safety. The procedures must include provisions for:

1. monitoring components or buildings according to the requirements of LAC 43:XIII.7707; [49 CFR 193.2503(a)]

2. startup and shutdown, including for initial startup, performance testing to demonstrate that components will operate satisfactory in service; [49 CFR 193.2503(b)]

3. recognizing abnormal operating conditions; [49 CFR 193.2503(c)]

4. purging and inerting components according to the requirements of LAC 43:XIII.7717; [49 CFR 193.2503(d)]

5. in the case of vaporization, maintaining the vaporization rate, temperature and pressure so that the resultant gas is within limits established for the vaporizer and the downstream piping; [49 CFR 193.2503(e)]

6. in the case of liquefaction, maintaining temperatures, pressures, pressure differentials and flow rates, as applicable, within their design limits for:

a. boilers; [49 CFR 193.2503(f)(1)]

b. turbines and other prime movers; [49 CFR 193.2503(f)(2)]

c. pumps, compressors, and expanders; [49 CFR 193.2503(f)(3)]

d. purification and regeneration equipment; and [49 CFR 193.2503(f)(4)]

e. equipment within cold boxes; [49 CFR 193.2503(f)(5)]

7. cooldown of components according to the requirements of LAC 43:XIII.7705. [49 CFR 193.2503(g)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1053 (June 2018).

§7705. Cooldown [49 CFR 193.2505]

A. The cooldown of each system of components that is subjected to cryogenic temperatures must be limited to a rate and distribution pattern that keeps thermal stresses within design limits during the cooldown period, paying particular attention to the performance of expansion and contraction devices. [49 CFR 193.2505(a)]

B. After cooldown stabilization is reached, cryogenic piping systems must be checked for leaks in areas of flanges, valves, and seals. [49 CFR 193.2505(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1053 (June 2018).

§7707. Monitoring Operations [49 CFR 193.2507]

A. Each component in operation or building in which a hazard to persons or property could exist must be monitored to detect fire or any malfunction or flammable fluid that could cause a hazardous condition. Monitoring must be accomplished by watching or listening from an attended control center for warning alarms, such as gas, temperature, pressure, vacuum, and flow alarms, or by conducting an inspection or test at intervals specified in the operating procedures. [49 CFR 193.2507]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1054 (June 2018).

§7709. Emergency Procedures [49 CFR 193.2509]

A. Each operator shall determine the types and places of emergencies other than fires that may reasonably be expected to occur at an LNG plant due to operating malfunctions, structural collapse, personnel error, forces of nature, and activities adjacent to the plant. [49 CFR 193.2509(a)]

B. To adequately handle each type of emergency identified under Subsection A of this Section and each fire emergency, each operator must follow one or more manuals of written procedures. The procedures must provide for the following:

1. responding to controllable emergencies, including notifying personnel and using equipment appropriate for handling the emergency; [49 CFR 193.2509(b)(1)]

2. recognizing an uncontrollable emergency and taking action to minimize harm to the public and personnel, including prompt notification of appropriate local officials of the emergency and possible need for evacuation of the public in the vicinity of the LNG plant; [49 CFR 193.2509(b)(2)]

3. coordinating with appropriate local officials in preparation of an emergency evacuation plan, which sets forth the steps required to protect the public in the event of an emergency, including catastrophic failure of an LNG storage tank; [49 CFR 193.2509(b)(3)]

4. cooperating with appropriate local officials in evacuations and emergencies requiring mutual assistance and keeping these officials advised of:

a. the LNG plant fire control equipment, its location, and quantity of units located throughout the plant; [49 CFR 193.2509(b)(4)(i)]

b. potential hazards at the plant, including fires; [49 CFR 193.2509(b)(4)(ii)]

c. communication and emergency control capabilities at the LNG plant; and [49 CFR 193.2509(b)(4)(iii)]

d. the status of each emergency. [49 CFR 193.2509(b)(4)(iv)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1054 (June 2018).

§7711. Personnel Safety [49 CFR 193.2511]

A. Each operator shall provide any special protective clothing and equipment necessary for the safety of personnel while they are performing emergency response duties. [49 CFR 193.2511(a)]

B. All personnel who are normally on duty at a fixed location, such as a building or yard, where they could be harmed by thermal radiation from a burning pool of impounded liquid, must be provided a means of protection at that location from the harmful effects of thermal radiation or a means of escape. [49 CFR 193.2511(b)]

C. Each LNG plant must be equipped with suitable first-aid material, the location of which is clearly marked and readily available to personnel. [49 CFR 193.2511(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1054 (June 2018).

§7713. Transfer Procedures [49 CFR 193.2513]

A. Each transfer of LNG or other hazardous fluid must be conducted in accordance with one or more manuals of written procedures to provide for safe transfers. [49 CFR 193.2513(a)]

B. The transfer procedures must include provisions for personnel to:

1. before transfer, verify that the transfer system is ready for use, with connections and controls in proper positions, including if the system could contain a combustible mixture, verifying that it has been adequately purged in accordance with a procedure which meets the requirements of "Purging Principles and Practices (incorporated by reference, see §6713)"; [49 CFR 193.2513(b)(1)]

2. before transfer, verify that each receiving container or tank vehicle does not contain any substance that would be incompatible with the incoming fluid and that there is sufficient capacity available to receive the amount of fluid to be transferred; [49 CFR 193.2513(b)(2)]

3. before transfer, verify the maximum filling volume of each receiving container or tank vehicle to ensure that expansion of the incoming fluid due to warming will not result in overfilling or overpressure; [49 CFR 193.2513(b)(3)]

4. when making bulk transfer of LNG into a partially filled (excluding cooldown heel) container, determine any differences in temperature or specific gravity between the LNG being transferred and the LNG already in the container and, if necessary, provide a means to prevent rollover due to stratification; [49 CFR 193.2513(b)(4)]

5. verify that the transfer operations are proceeding within design conditions and that overpressure or overfilling does not occur by monitoring applicable flow rates, liquid levels, and vapor returns; [49 CFR 193.2513(b)(5)]

6. manually terminate the flow before overfilling or overpressure occurs; and [49 CFR 193.2513(b)(6)]

7. deactivate cargo transfer systems in a safe manner by depressurizing, venting, and disconnecting lines and conducting any other appropriate operations. [49 CFR 193.2513(b)(7)]

C. In addition to the requirements of Subparagraph B of this Section, the procedures for cargo transfer must be located at the transfer area and include provisions for personnel to:

1. be in constant attendance during all cargo transfer operations; [49 CFR 193.2513(c)(1)]

2. prohibit the backing of tank trucks in the transfer area, except when a person is positioned at the rear of the truck giving instructions to the driver; [49 CFR 193.2513(c)(2)]

3. before transfer, verify that:

a. each tank car or tank truck complies with applicable regulations governing its use; [49 CFR 193.2513(c)(3)(i)]

b. all transfer hoses have been visually inspected for damage and defects; [49 CFR 193.2513(c)(3)(ii)]

c. each tank truck is properly immobilized with chock wheels, and electrically grounded; and [49 CFR 193.2513(c)(3)(iii)]

d. each tank truck engine is shut off unless it is required for transfer operations; [49 CFR 193.2513(c)(3)(iv)]

4. prevent a tank truck engine that is off during transfer operations from being restarted until the transfer lines have been disconnected and any released vapors have dissipated; [49 CFR 193.2513(c)(4)]

5. prevent loading LNG into a tank car or tank truck that is not in exclusive LNG service or that does not contain a positive pressure if it is in exclusive LNG service, until after the oxygen content in the tank is tested and if it exceeds 2 percent by volume, purged in accordance with a procedure that meets the requirements of “Purging Principles and Practices (incorporated by reference, see LAC 43:XIII.6713)”. [49 CFR 193.2513(c)(5)]

6. verify that all transfer lines have been disconnected and equipment cleared before the tank car or tank truck is moved from the transfer position; and [49 CFR 193.2513(c)(6)]

7. verify that transfers into a pipeline system will not exceed the pressure or temperature limits of the system. [49 CFR 193.2513(c)(7)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1054 (June 2018).

§7715. Investigations of Failures [49 CFR 193.2515]

A. Each operator shall investigate the cause of each explosion, fire, or LNG spill or leak which results in:

1. death or injury requiring hospitalization; or [49 CFR 193.2515(a)(1)]

2. property damage exceeding $10,000. [49 CFR 193.2515(a)(2)]

B. As a result of the investigation, appropriate action must be taken to minimize recurrence of the incident. [49 CFR 193.2515(b)]

C. If the commissioner investigates an incident, the operator involved shall make available all relevant information and provide reasonable assistance in conducting the investigation. Unless necessary to restore or maintain service, or for safety, no component involved in the incident may be moved from its location or otherwise altered until the investigation is complete or the investigating agency otherwise provides. Where components must be moved for operational or safety reasons, they must not be removed from the plant site and must be maintained intact to the extent practicable until the investigation is complete or the investigating agency otherwise provides. [49 CFR 193.2515(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1055 (June 2018).

§7717. Purging [49 CFR 193.2517]

A. When necessary for safety, components that could accumulate significant amounts of combustible mixtures must be purged in accordance with a procedure which meets the provisions of the “Purging Principles and Practices (incorporated by reference, see LAC 43:XIII.6713)” after being taken out of service and before being returned to service. [49 CFR 193.2517]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1055 (June 2018).

§7719. Communication Systems [49 CFR 193.2519]

A. Each LNG plant must have a primary communication system that provides for verbal communications between all operating personnel at their work stations in the LNG plant. [49 CFR 193.2519(a)]

B. Each LNG plant in excess of 70,000 gallons (265,000 liters) storage capacity must have an emergency communication system that provides for verbal communications between all persons and locations necessary for the orderly shutdown of operating equipment and the operation of safety equipment in time of emergency. The emergency communication system must be independent of and physically separated from the primary communication system and the security communication system under LAC 43:XIII.8509. [49 CFR 193.2519(b)]

C. Each communication system required by this part must have an auxiliary source of power, except sound-powered equipment. [49 CFR 193.2519(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1055 (June 2018).

§7721. Operating Records [49 CFR 193.2521]

A. operator shall maintain a record of results of each inspection, test and investigation required by this subpart. For each LNG facility that is designed and constructed after March 31, 2000 the operator shall also maintain related inspection, testing, and investigation records that NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713) requires. Such records, whether required by this part or NFPA-59A-2001, must be kept for a period of not less than five years. [49 CFR 193.2521]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1055 (June 2018).

Chapter 79. Maintenance [49 CFR Part 193 Subpart G]

§7901. Scope [49 CFR 193.2601]

A. This subpart prescribes requirements for maintaining components at LNG plants. [49 CFR 193.2601]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1056 (June 2018).

§7903. General [49 CFR 193.2603]

A. Each component in service, including its support system, must be maintained in a condition that is compatible with its operational or safety purpose by repair, replacement, or other means. [49 CFR 193.2603(a)]

B. An operator may not place, return, or continue in service any component which is not maintained in accordance with this subpart. [49 CFR 193.2603(b)]

C. Each component taken out of service must be identified in the records kept under §193.2639. [49 CFR 193.2603(c)]

D. If a safety device is taken out of service for maintenance, the component being served by the device must be taken out of service unless the same safety function is provided by an alternate means. [49 CFR 193.2603(d)]

E. If the inadvertent operation of a component taken out of service could cause a hazardous condition, that component must have a tag attached to the controls bearing the words “do not operate” or words of comparable meaning. [49 CFR 193.2603(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1056 (June 2018).

§7905. Maintenance Procedures [49 CFR 193.2605]

A. Each operator shall determine and perform, consistent with generally accepted engineering practice, the periodic inspections or tests needed to meet the applicable requirements of this subpart and to verify that components meet the maintenance standards prescribed by this subpart. [49 CFR 193.2605(a)]

B. Each operator shall follow one or more manuals of written procedures for the maintenance of each component, including any required corrosion control. The procedures must include:

1. the details of the inspections or tests determined under Subsection A of this Section and their frequency of performance; and [49 CFR 193.2605(b)(1)]

2. a description of other actions necessary to maintain the LNG plant according to the requirements of this Subpart. [49 CFR 193.2605(b)(2)]

3. each operator shall include in the manual required by Subsection B of this Section instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of LAC 43:XIII.313 of this Subchapter. [49 CFR 193.2605(b)(3)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1056 (June 2018).

§7907. Foreign Material [49 CFR 193.2607]

A. The presence of foreign material, contaminants, or ice shall be avoided or controlled to maintain the operational safety of each component. [49 CFR 193.2605(a)]

B. LNG plant grounds must be free from rubbish, debris, and other material which present a fire hazard. Grass areas on the LNG plant grounds must be maintained in a manner that does not present a fire hazard. [49 CFR 193.2605(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1056 (June 2018).

§7909. Support Systems [49 CFR 193.2609]

A. Each support system or foundation of each component must be inspected for any detrimental change that could impair support. [49 CFR 193.2609]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1056 (June 2018).

§7911. Fire Protection [49 CFR 193.2611]

A. Maintenance activities on fire control equipment must be scheduled so that a minimum of equipment is taken out of service at any one time and is returned to service in a reasonable period of time. [49 CFR 193.2611(a)]

B. Access routes for movement of fire control equipment within each LNG plant must be maintained to reasonably provide for use in all weather conditions. [49 CFR 193.2611(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1056 (June 2018).

§7913. Auxiliary Power Sources [49 CFR 193.2613]

A. Each auxiliary power source must be tested monthly to check its operational capability and tested annually for capacity. The capacity test must take into account the power needed to start up and simultaneously operate equipment that would have to be served by that power source in an emergency. [49 CFR 193.2613]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1056 (June 2018).

§7915. Isolating and Purging [49 CFR 193.2615]

A. Before personnel begin maintenance activities on components handling flammable fluids which are isolated for maintenance, the component must be purged in accordance with a procedure which meets the requirements of "Purging Principles and Practices (incorporated by reference, see LAC 43:XIII.6713)"; unless the maintenance procedures under LAC 43:XIII.7905 provide that the activity can be safely performed without purging. [49 CFR 193.2615(a)]

B. If the component or maintenance activity provides an ignition source, a technique in addition to isolation valves (such as removing spool pieces or valves and blank flanging the piping, or double block and bleed valving) must be used to ensure that the work area is free of flammable fluids. [49 CFR 193.2615(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1056 (June 2018).

§7917. Repairs [49 CFR 193.2617]

A. Repair work on components must be performed and tested in a manner which:

1. as far as practicable, complies with the applicable requirements of Subpart D of this part; and [49 CFR 193.2617(a)(1)]

2. assures the integrity and operational safety of the component being repaired. [49 CFR 193.2617(a)(2)]

B. For repairs made while a component is operating, each operator shall include in the maintenance procedures under LAC 43:XIII.7905 appropriate precautions to maintain the safety of personnel and property during repair activities. [49 CFR 193.2617(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1057 (June 2018).

§7919. Control Systems [49 CFR 193.2619]

A. Each control system must be properly adjusted to operate within design limits. [49 CFR 193.2619(a)]

B. If a control system is out of service for 30 days or more, it must be inspected and tested for operational capability before returning it to service. [49 CFR 193.2619(b)]

C. Control systems in service, but not normally in operation, such as relief valves and automatic shutdown devices, and control systems for internal shutoff valves for bottom penetration tanks must be inspected and tested once each calendar year, not exceeding 15 months, with the following exceptions.

1. Control systems used seasonally, such as for liquefaction or vaporization, must be inspected and tested before use each season. [49 CFR 193.2619(c)(1)]

2. Control systems that are intended for fire protection must be inspected and tested at regular intervals not to exceed 6 months. [49 CFR 193.2619(c)(2)]

D. Control systems that are normally in operation, such as required by a base load system, must be inspected and tested once each calendar year but with intervals not exceeding 15 months. [49 CFR 193.2619(d)]

E. Relief valves must be inspected and tested for verification of the valve seat lifting pressure and reseating. [49 CFR 193.2619(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1057 (June 2018).

§7921. Testing Transfer Hoses [49 CFR 193.2621]

A. Hoses used in LNG or flammable refrigerant transfer systems must be:

1. tested once each calendar year, but with intervals not exceeding 15 months, to the maximum pump pressure or relief valve setting; and [49 CFR 193.2621(a)]

2. visually inspected for damage or defects before each use. [49 CFR 193.2621(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1057 (June 2018).

§7923. Inspecting LNG Storage Tanks [49 CFR 193.2623]

A. Each LNG storage tank must be inspected or tested to verify that each of the following conditions does not impair the structural integrity or safety of the tank:

1. foundation and tank movement during normal operation and after a major meteorological or geophysical disturbance; [49 CFR 193.2623(a)]

2. inner tank leakage; [49 CFR 193.2623(b)]

3. effectiveness of insulation; [49 CFR 193.2623(c)]

4. frost heave. [49 CFR 193.2623(d)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1057 (June 2018).

§7925. Corrosion Protection [49 CFR 193.2625]

A. Each operator shall determine which metallic components could, unless corrosion is controlled, have their integrity or reliability adversely affected by external, internal, or atmospheric corrosion during their intended service life. [49 CFR 193.2625(a)]

B. Components whose integrity or reliability could be adversely affected by corrosion must be either:

1. protected from corrosion in accordance with LAC 43:XIII.7927 through LAC 43:XIII.7935, as applicable; or [49 CFR 193.2625(b)(1)]

2. inspected and replaced under a program of scheduled maintenance in accordance with procedures established under LAC 43:XIII.7905. [49 CFR 193.2625(b)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1057 (June 2018).

§7927. Atmospheric Corrosion Control [49 CFR 193.2627]

A. Each exposed component that is subject to atmospheric corrosive attack must be protected from atmospheric corrosion by:

1. material that has been designed and selected to resist the corrosive atmosphere involved; or [49 CFR 193.2627(a)]

2. suitable coating or jacketing. [49 CFR 193.2627(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1057 (June 2018).

§7929. External Corrosion Control: Buried or Submerged Components [49 CFR 193.2629]

A. Buried or submerged component that is subject to external corrosive attack must be protected from external corrosion by:

1. material that has been designed and selected to resist the corrosive environment involved; or [49 CFR 193.2629(a)(1)]

2. the following means:

a. an external protective coating designed and installed to prevent corrosion attack and to meet the requirements of §192.461 of this chapter; and [49 CFR 193.2629(a)(2)(i)]

b. a cathodic protection system designed to protect components in their entirety in accordance with the requirements of LAC 43:XIII.2115 of this chapter and placed in operation before October 23, 1981, or within 1 year after the component is constructed or installed, whichever is later. [49 CFR 193.2629(a)(2)(ii)]

B. Where cathodic protection is applied, components that are electrically interconnected must be protected as a unit. [49 CFR 193.2629(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1058 (June 2018).

§7931. Internal Corrosion Control [49 CFR 193.2631]

A. Each component that is subject to internal corrosive attack must be protected from internal corrosion by:

1. material that has been designed and selected to resist the corrosive fluid involved; or [49 CFR 193.2631(a)]

2. suitable coating, inhibitor, or other means. [49 CFR 193.2631(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1058 (June 2018).

§7933. Interference Currents [49 CFR 193.2633]

A. Each component that is subject to electrical current interference must be protected by a continuing program to minimize the detrimental effects of currents. [49 CFR 193.2633(a)]

B. Each cathodic protection system must be designed and installed so as to minimize any adverse effects it might cause to adjacent metal components. [49 CFR 193.2633(b)]

C. Each impressed current power source must be installed and maintained to prevent adverse interference with communications and control systems. [49 CFR 193.2633(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1058 (June 2018).

§7935. Monitoring Corrosion Control [49 CFR 193.2635]

A. Corrosion protection provided as required by this subpart must be periodically monitored to give early recognition of ineffective corrosion protection, including the following, as applicable.

1. Each buried or submerged component under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463 of this chapter. [49 CFR 193.2635(a)]

2. Each cathodic protection rectifier or other impressed current power source must be inspected at least 6 times each calendar year, but with intervals not exceeding 2 1/2 months, to ensure that it is operating properly. [49 CFR 193.2635(b)]

3. Each reverse current switch, each diode, and each interference bond whose failure would jeopardize component protection must be electrically checked for proper performance at least 6 times each calendar year, but with intervals not exceeding 2 1/2 months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months. [49 CFR 193.2635(c)]

4. Each component that is protected from atmospheric corrosion must be inspected at intervals not exceeding 3 years. [49 CFR 193.2635(d)]

5. If a component is protected from internal corrosion, monitoring devices designed to detect internal corrosion, such as coupons or probes, must be located where corrosion is most likely to occur. However, monitoring is not required for corrosion resistant materials if the operator can demonstrate that the component will not be adversely affected by internal corrosion during its service life. Internal corrosion control monitoring devices must be checked at least two times each calendar year, but with intervals not exceeding 7 1/2 months. [49 CFR 193.2635(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1058 (June 2018).

§7937. Remedial Measures [49 CFR 193.2637]

A. Prompt corrective or remedial action must be taken whenever an operator learns by inspection or otherwise that atmospheric, external, or internal corrosion is not controlled as required by this subpart. [49 CFR 193.2637]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1058 (June 2018).

§7939. Maintenance Records [49 CFR 193.2639]

A. Each operator shall keep a record at each LNG plant of the date and type of each maintenance activity performed on each component to meet the requirements of this part. For each LNG facility that is designed and constructed after March 31, 2000 the operator shall also maintain related periodic inspection and testing records that NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713) requires. Maintenance records, whether required by this part or NFPA-59A-2001, must be kept for a period of not less than five years. [49 CFR 193.2639(a)]

B. Each operator shall maintain records or maps to show the location of cathodically protected components, neighboring structures bonded to the cathodic protection system, and corrosion protection equipment. [49 CFR 193.2639(b)]

C. Each of the following records must be retained for as long as the LNG facility remains in service:

1. each record or map required by Subsection B of this Section. [49 CFR 193.2639(c)(1)]

2. records of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures. [49 CFR 193.2639(c)(2)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1058 (June 2018).

Chapter 81. Personnel Qualifications and Training [49 CFR Part 193 Subpart H]

§8101. Scope [49 CFR 193.2701]

A. This subpart prescribes requirements for personnel qualifications and training.

[45 FR 9219, Feb. 11, 1980] [49 CFR 193.2701]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.
HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1059 (June 2018).

§8103. Design and Fabrication [49 CFR 193.2703]

A. For the design and fabrication of components, each operator shall use:

1. with respect to design, persons who have demonstrated competence by training or experience in the design of comparable components; [49 CFR 193.2703(a)]

2. with respect to fabrication, persons who have demonstrated competence by training or experience in the fabrication of comparable components. [49 CFR 193.2703(b)] [45 FR 9219, Feb. 11, 1980]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1059 (June 2018).

§8105. Construction, Installation, Inspection, and Testing [49 CFR 193.2705]

A. Supervisors and other personnel utilized for construction, installation, inspection, or testing must have demonstrated their capability to perform satisfactorily the assigned function by appropriate training in the methods and equipment to be used or related experience and accomplishments. [49 CFR 193.2705(a)]

B. Each operator must periodically determine whether inspectors performing construction, installation, and testing duties required by this part are satisfactorily performing their assigned functions. [49 CFR 193.2705(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1059 (June 2018).

§8107. Operations and Maintenance [49 CFR 193.2707]

A. Each operator shall utilize for operation or maintenance of components only those personnel who have demonstrated their capability to perform their assigned functions by:

1. successful completion of the training required by LAC 43:XIII.8113 and LAC 43:XIII.8117; and [49 CFR 193.2707(a)(1)]

2. experience related to the assigned operation or maintenance function; and [49 CFR 193.2707(a)(2)]

3. acceptable performance on a proficiency test relevant to the assigned function. [49 CFR 193.2707(a)(3)]

B. A person who does not meet the requirements of Subsection A of this Section may operate or maintain a component when accompanied and directed by an individual who meets the requirements. [49 CFR 193.2707(b)

C. Corrosion control procedures under LAC 43:XIII.7905(b), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in corrosion control technology. [49 CFR 193.2707(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1059 (June 2018).

§8109. Security [49 CFR 193.2709]

A. Personnel having security duties must be qualified to perform their assigned duties by successful completion of the training required under LAC 43:XIII.8115. [49 CFR 193.2709]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1059 (June 2018).

§8111. Personnel Health [49 CFR 193.2711]

A. Each operator shall follow a written plan to verify that personnel assigned operating, maintenance, security, or fire protection duties at the LNG plant do not have any physical condition that would impair performance of their assigned duties. The plan must be designed to detect both readily observable disorders, such as physical handicaps or injury, and conditions requiring professional examination for discovery. [49 CFR 193.2711]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1059 (June 2018).

§8113. Training: Operations and Maintenance [49 CFR 193.2713]

A. Each operator shall provide and implement a written plan of initial training to instruct:

1. all permanent maintenance, operating, and supervisory personnel:

a. about the characteristics and hazards of LNG and other flammable fluids used or handled at the facility, including, with regard to LNG, low temperatures, flammability of mixtures with air, odorless vapor, boiloff characteristics, and reaction to water and water spray; [49 CFR 193.2713(a)(1)(i)]

b. about the potential hazards involved in operating and maintenance activities; and [49 CFR 193.2713(a)(1)(ii)]

c. to carry out aspects of the operating and maintenance procedures under LAC 43:XIII.7703 and LAC 43:XIII.7905 that relate to their assigned functions; and [49 CFR 193.2713(a)(1)(iii)]

2. all personnel:

a. to carry out the emergency procedures under LAC 43:XIII.7709 that relate to their assigned functions; and [49 CFR 193.2713(a)(2)(i)]

b. to give first-aid; and [49 CFR 193.2713(a)(2)(ii)]

3. all operating and appropriate supervisory personnel—

a. to understand detailed instructions on the facility operations, including controls, functions, and operating procedures; and [49 CFR 193.2713(a)(3)(i)]

b. to understand the LNG transfer procedures provided under LAC 43:XIII.7713. [49 CFR 193.2713(a)(3)(ii)]

B. A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel current on the knowledge and skills they gained in the program of initial instruction. [49 CFR 193.2713(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1059 (June 2018).

§8115. Training: Security [49 CFR 193.2715]

A. Personnel responsible for security at an LNG plant must be trained in accordance with a written plan of initial instruction to:

1. recognize breaches of security; [49 CFR 193.2715(a)(1)]

2. carry out the security procedures under LAC 43:XIII.8503 that relate to their assigned duties; [49 CFR 193.2715(a)(2)]

3. be familiar with basic plant operations and emergency procedures, as necessary to effectively perform their assigned duties; and [49 CFR 193.2715(a)(3)]

4. recognize conditions where security assistance is needed. [49 CFR 193.2715(a)(4)]

B. A written plan of continuing instruction must be conducted at intervals of not more than two years to keep all personnel having security duties current on the knowledge and skills they gained in the program of initial instruction. [49 CFR 193.2715(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1060 (June 2018).

§8117. Training: Fire Protection [49 CFR 193.2717]

A. All personnel involved in maintenance and operations of an LNG plant, including their immediate supervisors, must be trained according to a written plan of initial instruction, including plant fire drills, to:

1. know the potential causes and areas of fire; [49 CFR 193.2717(a)(1)]

2. know the types, sizes, and predictable consequences of fire; and [49 CFR 193.2717(a)(2)]

3. know and be able to perform their assigned fire control duties according to the procedures established under LAC 43:XIII.7709 and by proper use of equipment provided under LAC 43:XIII.8301. [49 CFR 193.2717(a)(3)]

B. A written plan of continuing instruction, including plant fire drills, must be conducted at intervals of not more than two years to keep personnel current on the knowledge and skills they gained in the instruction under Subsection A of the Section. [49 CFR 193.2717(b)]

C. Plant fire drills must provide personnel hands-on experience in carrying out their duties under the fire emergency procedures required by §193.2509. [49 CFR 193.2717(c)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1060 (June 2018).

§8119. Training: Records [49 CFR 193.2719]

A. Each operator shall maintain a system of records which:

1. provide evidence that the training programs required by this subpart have been implemented; and [49 CFR 193.2719(a)(1)]

2. provide evidence that personnel have undergone and satisfactorily completed the required training programs. [49 CFR 193.2719(a)(2)]

B. Records must be maintained for one year after personnel are no longer assigned duties at the LNG plant. [49 CFR 193.2719(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1060 (June 2018).

Chapter 83. Fire Protection [49 CFR Part 193 Subpart I]

§8301. Fire Protection [49 CFR 193.2801]

A. Each operator must provide and maintain fire protection at LNG plants according to sections 9.1 through 9.7 and section 9.9 of NFPA-59A-2001 (incorporated by reference, see LAC 43:XIII.6713). However, LNG plants existing on March 31, 2000, need not comply with provisions on emergency shutdown systems, water delivery systems, detection systems, and personnel qualification and training until September 12, 2005. [49 CFR 193.2801]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1060 (June 2018).

Chapter 85 Security [49 CFR Part 193 Subpart J]

§8501. Scope [49 CFR 193.2901]

A. This subpart prescribes requirements for security at LNG plants. However, the requirements do not apply to existing LNG plants that do not contain LNG. [49 CFR 193.2901]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1060 (June 2018).

§8503. Security Procedures [49 CFR 193.2903]

A. Each operator shall prepare and follow one or more manuals of written procedures to provide security for each LNG plant. The procedures must be available at the plant in accordance with LAC 43:XIII.6717 and include at least:

1. a description and schedule of security inspections and patrols performed in accordance with §193.2913; [49 CFR 193.2903(a)]

2. a list of security personnel positions or responsibilities utilized at the LNG plant; [193.2903(b)]

3. a brief description of the duties associated with each security personnel position or responsibility; [49 CFR 193.2903(c)]

4. instructions for actions to be taken, including notification of other appropriate plant personnel and law enforcement officials, when there is any indication of an actual or attempted breach of security; [49 CFR 193.2903(d)]

5. methods for determining which persons are allowed access to the LNG plant; [49 CFR 193.2903(e)]

6. positive identification of all persons entering the plant and on the plant, including methods at least as effective as picture badges; and [49 CFR 193.2903(f)]

7. liaison with local law enforcement officials to keep them informed about current security procedures under this section. [49 CFR 193.2903(g)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1060 (June 2018).

§8505. Protective Enclosures [49 CFR 193.2905]

A. The following facilities must be surrounded by a protective enclosure:

1. storage tanks; [49 CFR 2905(a)(1)]

2. impounding systems; [49 CFR 2905(a)(2)]

3. vapor barriers; [49 CFR 2905(a)(3)]

4. cargo transfer systems; [49 CFR 2905(a)(4)]

5. process, liquefaction, and vaporization equipment; [49 CFR 2905(a)(5)]

6. control rooms and stations; [49 CFR 2905(a)(6)]

7. control systems; [49 CFR 2905(a)(7)]

8. fire control equipment; [49 CFR 2905(a)(8)]

9. security communications systems; and [49 CFR 2905(a)(9)]

10. alternative power sources. [49 CFR 2905(a)(10)]

B. The protective enclosure may be one or more separate enclosures surrounding a single facility or multiple facilities.

C. Ground elevations outside a protective enclosure must be graded in a manner that does not impair the effectiveness of the enclosure. [49 CFR 193.2905(b)]

D. Protective enclosures may not be located near features outside of the facility, such as trees, poles, or buildings, which could be used to breach the security. [49 CFR 193.2905(c)]

E. At least two accesses must be provided in each protective enclosure and be located to minimize the escape distance in the event of emergency. [49 CFR 193.2905(d)]

F. Each access must be locked unless it is continuously guarded. During normal operations, an access may be unlocked only by persons designated in writing by the operator. During an emergency, a means must be readily available to all facility personnel within the protective enclosure to open each access. [49 CFR 193.2905(e)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1061 (June 2018).

§8507. Protective Enclosure Construction [49 CFR 193.2907]

A. A protective enclosure must have sufficient strength and configuration to obstruct unauthorized access to the facilities enclosed. [49 CFR 193.2907(a)]

B. Openings in or under protective enclosures must be secured by grates, doors or covers of construction and fastening of sufficient strength such that the integrity of the protective enclosure is not reduced by any opening. [49 CFR 193.2907(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1061 (June 2018).

§8509. Security Communications [49 CFR 193.2909]

A. A means must be provided for:

1. prompt communications between personnel having supervisory security duties and law enforcement officials; and [49 CFR 193.2909(a)]

2. direct communications between all on-duty personnel having security duties and all control rooms and control stations. [49 CFR 193.2909(b)]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1061 (June 2018).

§8511. Security Lighting [49 CFR193.2911]

A. Where security warning systems are not provided for security monitoring under LAC 43:XIII.8513, the area around the facilities listed under LAC 43:XIII.8505(a) and each protective enclosure must be illuminated with a minimum in service lighting intensity of not less than 2.2 lux (0.2 ft^c) between sunset and sunrise. [49 CFR 193.2911]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1061 (June 2018).

§8513. Security Monitoring [49 CFR 193.2913]

A. Each protective enclosure and the area around each facility listed in LAC 43:XIII.8505(a) must be monitored for the presence of unauthorized persons. Monitoring must be by visual observation in accordance with the schedule in the security procedures under LAC 43:XIII.8503(a) or by security warning systems that continuously transmit data to an attended location. At an LNG plant with less than 40,000 m^3 (250,000 bbl) of storage capacity, only the protective enclosure must be monitored. [49 CFR 193.2913]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1061 (June 2018).

§8515. Alternative Power Sources [49 CFR 193.2915]

A. An alternative source of power that meets the requirements of LAC 43:XIII.7545 must be provided for security lighting and security monitoring and warning systems required under LAC 43:XIII.8511 and LAC 43:XIII.8513. [49 CFR 193.2915]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1061 (June 2018).

§8517. Warning Signs [49 CFR 193.2917]

A. Warning signs must be conspicuously placed along each protective enclosure at intervals so that at least one sign is recognizable at night from a distance of 30m (100 ft.) from any way that could reasonably be used to approach the enclosure. [49 CFR 193.2917(a)]

B. Signs must be marked with at least the following on a background of sharply contrasting color. The words “NO TRESPASSING,” or words of comparable meaning. [49 CFR 193.2917(b)] [Amdt. 193-2, 45 FR 70409, Oct. 23, 1980, as amended at 47 FR 32720, July 29, 1982]

AUTHORITY NOTE: Promulgated in accordance with R.S. 30:551.C.

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 44:1062 (June 2018).