Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation – Pipeline Safety

Louisiana Pipeline Safety
Gas Regulations

[CFR Part 191 and 192]
(through amendment 191-16 & 192-103)
(effective March 2007)

Code sections numbers in the table of contents written in blue and/or underlined represent where there exist any differences between Title 43 and CFR Part 191 and 192. The actual differences in these code sections are written in blue and/or underlined.

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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, 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).

§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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 2. Transportation of Natural 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, and annual pipeline summary data by operators of gas pipeline facilities located in Louisiana. [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 outside of the following areas: [49 CFR 191.1(b)(4)]

a. an area within the limits of any incorporated or unincorporated city, town, or village; [49 CFR 191.1(b)(4)(i)]

b. any designated residential or commercial area such as a subdivision, business or shopping center, or community development. [49 CFR 191.1(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).

§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.

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 or of liquefied natural gas or gas from an LNG facility; and

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

ii. estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more;

b. an event that results in an emergency shutdown of an LNG facility;

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.

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.

AUTHORITY 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).

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

A. At the earliest practicable moment, within two hours following 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 shall be made by telephone to 1-(800) 424-8802 (federal) and (225) 342-5585 (day) or (225) 342-5505 (after working hours)(state) and shall 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)]

AUTHORITY 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).

§307. Addressee for Written Reports [49 CFR 191.7]

A. One copy of each written report, required by Part XIII, for intrastate facilities subject to the jurisdiction of the Office of Conservation pursuant to certification under Section 5(a) of the Natural Gas Pipeline Safety Act must be submitted to the Commissioner of Conservation, P.O. Box 94275, Baton Rouge, LA 70804-9275. One copy of each written report required by Part XIII must be submitted to the Information Resources Manager, Office of Pipeline Safety, *Pipeline and Hazardous Materials Safety Administration*, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW, Washington, DC 20590. Safety-related condition reports required by §323 for intrastate pipeline transportation must be submitted concurrently to that state agency, and if that agency acts as an agent of the secretary with respect to interstate transmission facilities, safety-related condition reports for these facilities must be submitted concurrently to that agency. [49 CFR 191.7]

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 9:219 (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).

§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. The incident report required by this Section need not be submitted with respect to master meter systems or LNG facilities. [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), amended LR 30:1222 (June 2004).

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

A. Except as provided in Subsection B of this Section, each operator of a distribution pipeline system shall submit an annual report for that system on Department of Transportation Form RSPA 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. The annual report required by this Section need not be submitted with respect to: [49 CFR 191.11(b)]

1. petroleum gas systems which serve fewer than 100 customers from a single source; [49 CFR 191.11(b)(1)]

2. master meter systems; or [49 CFR 191.11(b)(2)]

3. LNG facilities. [49 CFR 191.11(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 9:219 (April 1983), amended LR 10:511 (July 1984), LR 11:255 (March 1985), LR 30:1222 (June 2004).

§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 and Gathering Systems: Incident Report [49 CFR 191.15]

A. Except as provided in Subsection C of this Section, each operator of a transmission or a gathering pipeline system shall submit Department of Transportation Form RSPA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §305. [49 CFR 191.15(a)]

B. Where additional related information is obtained after a report is submitted under Subsection A of this Section, the operator shall make a supplemental report as soon as practicable with a clear reference by date and subject to the original report. [49 CFR 191.15(b)]

C. The incident report required by Subsection A of this Section need not be submitted with respect to LNG facilities. [49 CFR 191.15(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 11:255 (March 1985), LR 30:1222 (June 2004).

§317. Transmission and Gathering Systems: Annual Report [49 CFR 191.17]

A. Except as provided in Subsection B of this Section, each operator of a transmission or a gathering pipeline system shall submit an annual report for that system on Department of Transportation Form RSPA 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. [49 CFR 191.17(a)]

B. The annual report required by Subsection A of this Section need not be submitted with respect to LNG facilities. [49 CFR 191.17(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 11:256 (March 1985), LR 30:1222 (June 2004).

§319. Report Forms [49 CFR 191.19]

A. Copies of the prescribed report forms are available without charge upon request from the address given in §307. Additional copies in this prescribed format may be reproduced and used if in the same size and kind of paper. In addition, the information required by these forms may be submitted by any other means that is acceptable to the commissioner/administrator. [49 CFR 191.19]

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 9:219 (April 1983), amended LR 10:511 (July 1984), LR 11:256 (March 1985), LR 20:442 (April 1994), LR 24:1307 (July 1998), LR 30:1222 (June 2004).

§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 gas pipeline information collection requirements of the Office of Pipeline Safety pursuant to the Paperwork Reduction Act of 1980, Public Law 96-511. It is the intent of this Section to comply with the requirements of Section 3507(f) of the Paperwork Reduction Act which requires that agencies 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	RSPA 7100.1
191.11	RSPA 7100.1-1
191.15	RSPA 7100.2
191.17	RSPA 7100.2-1

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 11:256 (March 1985), amended LR 20:442 (April 1994), LR 30:1222 (June 2004).

§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. 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 an LNG facility that contains, controls, or processes gas or LNG; [49 CFR 191.23(a)(2)]

3. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes gas or LNG; [49 CFR 191.23(a)(3)]

4. 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; [49 CFR 191.23(a)(4)]

5. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure limiting or control devices; [49 CFR 191.23(a)(5)]

6. a leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency; [49 CFR 191.23(a)(6)]

7. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of a LNG storage tank; [49 CFR 191.23(a)(7)]

8. 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 or a LNG facility that contains or processes gas or LNG. [49 CFR 191.23(a)(8)]

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 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, except that reports are required for conditions under Paragraph A.1 of this Section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline. [49 CFR 191.23(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 30:1223 (June 2004).

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

A. Each report of a safety-related condition under §323.A must be filed concurrently (received by the commissioner and associate administrator, OPS) in writing within five working days (not including Saturday, Sunday, state or federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. To file a report by facsimile (FAX), dial (225) 342-5529 (state) and (202) 366-7128 (federal). [49 CFR 191.25]

B. The report must be headed "Safety-Related Condition Report" and provide the following information: [49 CFR 191.25(b)]

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

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

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

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

5. date condition was discovered and date condition was first determined to exist; [49 CFR 191.25(b)(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(b)(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(b)(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(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 30:1223 (June 2004).

§327. Filing Offshore Pipeline Condition Reports [49 CFR 191.27]

A. Each operator shall, within 60 days after completion of the inspection of all its underwater pipelines subject to §2712.A, report the following information: [49 CFR 191.27(a)]

1. name and principal address of operator; [49 CFR 191.27(a)(1)]

2. date of report; [49 CFR 191.27(a)(2)]

3. name, job title, and business telephone

number of person submitting the report; [49 CFR 191.27(a)(3)]

4. total length of pipeline inspected; [49 CFR 191.27(a)(4)]

5. length and date of installation of each exposed pipeline segment, and location, including, if available, the location according to the Minerals Management Service or state offshore area and block number tract; [49 CFR 191.27(a)(5)]

6. length and date of installation of each pipeline segment, if different from a pipeline segment identified under Paragraph A.5 of this Section, that is a hazard to navigation, and the location, including, if available, the location according to the Minerals Management Service or state offshore area and block number tract. [49 CFR 191.27(a)(6)]

B. The report shall be mailed to the Commissioner of Conservation, Office of Conservation, P.O. Box 94275, Baton Rouge, LA 70804-9275 and concurrently to the Information Officer, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, 400 Seventh Street, SW, Washington, DC 20590. [49 CFR 191.27(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 18:854 (August 1992), amended LR 20:443 (April 1994), LR 30:1224 (June 2004), LR 33:474 (March 2007).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 5. General [Subpart A]

§501. What is the scope of this Part [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); and [49 CFR 192.1(b)(4)(ii)]

c. within inlets of the Gulf of Mexico, except for the requirements in §2712 [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; or [49 CFR 192.1(b)(*5*)(i)]

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 33:474 (March 2007).

§503. Definitions [49 CFR 192.3]

A. As used in this Part:

Abandoned--permanently removed from service.

Administrator--the administrator, *Pipeline and Hazardous Materials Safety Administration* or his or her delegate

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.

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.

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.

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 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 beyond the meter or regulator, which ultimate outlet may, but need to 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.

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.

AUTHORITY 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).

§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 one-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)]

AUTHORITY 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).

§507. Incorporation by Reference [49 CFR 192.7]

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. [49 CFR 192.7(a)]

B. All incorporated materials are available for inspection in the *Pipeline and Hazardous Materials Safety Administration*, 400 Seventh Street, SW., Washington, DC, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or go to: http://www.archives.gov/federal_register/code_of_federal_regulations/ibr_locations.html. These materials have been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. In addition, the incorporated materials are available from the respective organizations listed in Paragraph C.1 of this section. [49 CFR 192.7(b)]

C. The full titles of documents incorporated by reference, in whole or in part, are provided herein. The numbers in parentheses indicate applicable editions. For each incorporated document, citations of all affected sections are provided. Earlier editions of currently listed documents or editions of documents listed in previous editions of 49 CFR Part 192 may be used for materials and components designed, manufactured, or installed in accordance with these earlier documents at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR Part 192 for a listing of the earlier listed editions or documents. [49 CFR 192.7(c)]

1. Incorporated by reference (ibr). List of Organizations and Addresses. [49 CFR 192.7(c)(1)]

a. Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, Houston, TX 77098.

b. American Petroleum Institute (API), 1220 L Street, NW., Washington, DC 20005.

c. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.

d. ASME International (ASME), Three Park

Avenue, New York, NY 10016-5990.

e. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, NE., Vienna, VA 22180.

f. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101.

g. Plastics Pipe Institute, Inc. (PPI), 1825 Connecticut Avenue, NW., Suite 680, Washington, DC 20009.

h. NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084.

i. Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018.

2. Documents incorporated by reference (Numbers in Parentheses Indicate Applicable Editions).

Source and name of referenced material	Title 43 reference
A. Pipeline Research Council International (PRCI):	
(1) AGA Pipeline Research Committee,Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe"(December 22, 1989). The RSTRENG program may be used for calculating remaining strength.	§§ 3333.A; 2137.C.
B. American Petroleum Institute (API):	
(1) API Specification 5L "Specification for Line Pipe" (43rd edition and errata, 2004).	§§ 705.E; 913; §5103 Item I.
(2) API Recommended Practice 5L1 "Recommended Practice for Railroad Transportation of Line Pipe" (6th edition, 2002).	§715.A.1.
(3) API Specification 6D "Pipeline Valves" (22nd edition, January 2002).	§1105.A.
(4) API Recommended Practice 80 (API RP 80) "Guidelines for the Definition of Onshore Gas Gathering Lines" (1st edition, April 2000)	§508
(5) API 1104 "Welding of Pipelines and Related Facilities" (19th edition, 1999, including Errata October 31, 2001).	§§ 1307.A; 1309.C.1; 1321.C; 5103 Item II.
(6) API Recommended Practice 1162 "Public Awareness Programs for Pipeline Operators," (1st edition, December 2003)	§2716
C. American Society for Testing and Materials (ASTM):	
(1) ASTM Designation: A 53/A53M-04a (2004) "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc Coated, Welded and Seamless".	§§ 913; 5103 Item I.
(2) ASTM Designation: A106/A106M-04b (2004) "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service".	§§ 913; 5103 Item I.
(3) ASTM Designation: A333/A333M-05 (2005) "Standard Specification for Seamless and Welded Steel Pipe for Low- Temperature	§§ 913; 5103 Item I.

Service".	
(4) ASTM Designation: A372/A372M-03 (2003) "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels".	§1137.B.1.
(5) ASTM Designation: A381-96 (Reapproved 2001) "Standard Specification for Metal-Arc-Welded Steel Pipe for Use With High-Pressure Transmission Systems".	§§ 913; 5103 Item I.
(6) ASTM Designation: A671-04 (2004) "Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures".	§§ 913; 5103 Item I.
(7) ASTM Designation: A672-96 (Reapproved 2001) "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures".	§§ 913; 5103 Item I.
(8) ASTM Designation: A691 "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High- Pressure Service at High Temperatures".	§§ 913; 5103 Item I.
(9) ASTM Designation: D638-03 "Standard Test Method for Tensile Properties of Plastics".	§§ 1513.A.3; 1513.B.1.
(10) ASTM Designation: D2513-87 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings".	§ 713.A.1.
(11) ASTM Designation: D2513-99 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings.	§§ 1151.B; 1511.B.2; 1513.A.1.a; 5103 Item I.
(12) ASTM Designation: D 2517-00 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings".	§§ 1151.A; 1511.D.1; 1513.A.1.b; 5103 Item I.
(13) ASTM Designation: F1055-1998 "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing".	§ 1513.A.1.c.
D. ASME International (ASME):	
(1) ASME B16.1-1998 "Cast Iron Pipe Flanges and Flanged Fittings".	§ 1107.C.
(2) ASME B16.5-2003 (October 2004) "Pipe Flanges and Flanged Fittings".	§§ 1107.A; 1509.
(3) ASME B31G-1991 (Reaffirmed 2004)"Manual for Determining the Remaining Strength of Corroded Pipelines".	§§ 2137.C; 3333.A.
(4) ASME B31.8-2003 (February 2004) "Gas Transmission and Distribution Piping Systems".	§2719.A.1.a.
(5) ASME B31.8S-2004 "Supplement to B31.8 on Managing System Integrity of Gas Pipelines".	§§ 3303.C; 3307.B; 3311.A; 3311.A.9; 3311.A.11;

	3311.A.12; 3311.A.13; 3313.A; 3313.B.1; 3317.A; 3317.B; 3317.C; 3317.E.1; 3317.E.4; 3321.A.1; 3323.B.2; 3323.B.3; 3325.B; 3325.B.1; 3325.B.2; 3325.B.3; 3325.B.4; 3327.B; 3327.C.1.a; 3329.B.1; 3329.B.2; 3333.A; 3333.D.1; 3333.D.1.a; 3335.A; 3335.B.1.d; 3337.C.1; 3339.A.1.a.i; 3339.A.1.a.ii; 3339.A.3.1.c; 3345.A.
(6) ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers (2004 edition including addenda through July 1, 2005).	§ 1113.A.
(7) ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, "Rules for Construction of Pressure Vessels," (2004 edition, including addenda through July 1, 2005).	§§ 1113.A; 1113.B; 1113.D; 1125.B.3.
(8) ASME Boiler and Pressure Vessel Code, Section VIII, Division 2, "Rules for Construction of Pressure Vessels-Alternative Rules," (2004 edition, including addenda through July 1, 2005).	§§ 1113.B; 1125.B.3.
(9) ASME Boiler and Pressure Vessel Code, Section IX, "Welding and Brazing Qualifications" (2004 edition, including addenda through July 1, 2005).	§§ 1307.A; 5103 Item II.
E. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS):	
(1) MSS SP44-1996(Reaffirmed; 2001) "Steel Pipe Line Flanges". (2) [Reserved]	§ 1107.A.
F. National Fire Protection Association (NFPA):	
(1) NFPA 30 (2003) "Flammable and Combustible Liquids Code".	§2935.B.
(2) NFPA 58 (2004) "Liquefied Petroleum Gas Code (LP-Gas Code)".	§§ 511.A; 511.B; 511.C.
(3) NFPA 59 (2004) "Utility LP-Gas Plant Code".	§§ 511.A; 511.B; 511.C
(4) NFPA 70 (2005) "National Electrical Code".	§§ 1123.E; 1149.C.
G. Plastics Pipe Institute, Inc. (PPI):	
(1) PPI TR-3/2004 (2004) "Policies and Procedures for Developing Hydrostatic Design Bases (HDB), Pressure Design	§921.

Bases (PDB), Strength Design Basis (SDB), and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe.	
H. NACE International (NACE):	
(1) NACE Standard RP-0502-2002 “Pipeline External Corrosion Direct Assessment Methodology”.	§§ 3323.B.1; 3325.B; 3325.B.1; 3325.B.1.b; 3325.B.2; 3325.B.3; 3325.B.3.b; 3325.B.3.d; 3325.B.4; 3325.B.4.b; 3331.D; 3335.B.1.d; 3339.A.2.
I. Gas Technology Institute (GTI). (Formerly Gas Research Institute):	
(1) GRI 02/0057 (2002) “Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology”.	§§ 3327.C.2; 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 30:1226 (June 2004), amended LR 31:681 (March 2005), LR 33:474 (March 2007).

§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; and [49 CFR 192.8(b)(1)]

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	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.

		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.	

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

HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, LR 33:476 (March 2007).

§509. What requirements apply to gathering lines? [49 CFR 192.9]

A. 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 §1100 and in 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 and in Chapter 33 of this subpart. However, an operator of a Type A regulated onshore gathering line 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; [49 CFR 192.9(d)(1)]

2. If the pipeline is metallic, control corrosion according to requirements of Chapter 21 of this subpart applicable to transmission lines; [49 CFR 192.9(d)(2)]

3. Carry out a damage prevention program under §2714; [49 CFR 192.9(d)(3)]

4. Establish a public education program under §2716; [49 CFR 192.9(d)(4)]

5. Establish the MAOP of the line under §2719; and [49 CFR 192.9(d)(5)]

6. Install and maintain line markers according to the requirements for transmission lines in §2907. [49 CFR 192.9(d)(6)]

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).

§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), LR33:477 (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 ANSI/NFPA 58 and 59. [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 ANSI/NFPA 58 and 59. [49 CFR 192.11(b)]

C. In the event of a conflict between this Subpart and ANSI/NFPA 58 and 59, ANSI/NFPA 58 and 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).

§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)]

AUTHORITY 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).

§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 9:217 (April 1983), amended LR 10:509 (July 1984), LR 30:1228 (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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 7. Materials [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 Specification 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).

§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; and [49 CFR 192.59(a)(1)]

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

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)]

AUTHORITY 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).

§713. Marking of Materials [49 CFR 192.63]

A. Except as provided in Subsection D of this Section each valve, fitting, length of pipe, and other component must be marked: [49 CFR 192.63(a)]

1. as prescribed in the specification or standard to which it was manufactured, except that thermoplastic fittings must be marked in accordance with ASTM D 2513; or [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)]

AUTHORITY 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).

§715. Transportation of Pipe [49 CFR 192.65]

A. 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: [49 CFR 192.65]

1. the transportation is performed in accordance with API RP 5L1; [49 CFR 192.65(a)]

2. in the case of pipe transported before November 12, 1970, the pipe is tested in accordance with Chapter 23 of this Subpart to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a Class 1 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 Subpart, the test pressure must be maintained for at least eight hours. [49 CFR 192.65(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 20:444 (April 1994), LR 30:1229 (June 2004).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 9. Pipe Design [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).

§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 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).

§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 Temp. in degrees Fahrenheit (Celsius)	Temp. 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. Subject to the limitations of §923, the design pressure for plastic pipe is determined in accordance with either of the following formulas.

$$P = 2S \frac{t}{(D - t)} 0.32$$

$$P = \frac{2S}{(SDR - 1)} 0.32$$

where:

P = Design pressure, gauge, psig (kPa)

S = For thermoplastic pipe, the HDB 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 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 of PPI TR-3/2004 HDB/PDB/MRS Policies, (ibr, 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. [49 CFR 192.121]

AUTHORITY 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 18:855 (August 1992), 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).

§923. Design Limitations for Plastic Pipe [49 CFR 192.123]

A. Except as provided in Subsection E of this Section, the design pressure may not exceed a gauge pressure of 125 psig (862 kPa) for plastic pipe used in: [49 CFR 192.123(a)]

1. distribution systems; or [49 CFR 192.123(a)(1)]
2. Classes 3 and 4 locations. [49 CFR 192.123(a)(2)]

B. Plastic pipe may not be used where operating temperatures of the pipe will be: [49 CFR 192.123(b)]

1. 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 192.123(b)(1)]
2. above the following applicable temperatures: [49 CFR 192.123(b)(2)]
   a. for thermoplastic pipe, the temperature at which the HDB used in the design formula under §921 is determined. [49 CFR 192.123(b)(2)(i)]
   b. for reinforced thermosetting plastic pipe, 150°F (66°C). [49 CFR 192.123(b)(2)(ii)]

C. The wall thickness for thermoplastic pipe may not be less than 0.062 in. (1.57 millimeters). [49 CFR

192.123(c)]

D. The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table. [49 CFR 192.123(d)]

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)

E. The design pressure for thermoplastic pipe produced after July 14, 2004 may exceed a gauge pressure of 100 psig (689 kPa) provided that: [49 CFR 192.123(e)]

1. the design pressure does not exceed 125 psig (862 kPa); [49 CFR 192.123(e)(1)]

2. the material is a PE2406 or a PE3408 as specified within ASTM D2513 (incorporated by reference, see §507); [49 CFR 192.123(e)(2)]

3. the pipe size is nominal pipe size (IPS) 12 or less; and [49 CFR 192.123(e)(3)]

4. the design pressure is determined in accordance with the design equation defined in §921. [49 CFR 192.123(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 9:222 (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).

§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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 11. Design of Pipeline Components [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]

AUTHORITY 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).

§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 API 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 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 pressure containing parts made of ductile iron may be used in the gas pipe components of compressor stations. [49 CFR 192.145(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 9:223 (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).

§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, MSS SP-44, or the equivalent. [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 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).

§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)]

AUTHORITY 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).

§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. [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 10¾ 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 31:683 (March 2005), LR 33:479 (March 2007).

§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 Section VIII, Division 1 of the ASME Boiler and Pressure Vessel Code. [49 CFR 192.153(a)]

B. Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with Section VIII, Division 1, or Section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, 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 Section VIII of the ASME Boiler and Pressure Code, 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)]

AUTHORITY 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).

§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 National Electrical Code, ANSI/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).

§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, 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).

§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 = (D x P x F)/(48.33)(C=(3D x P x

F/1,000))

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).

§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 A 372/A 372M. [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).

§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).

§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, ANSI/NFPA 70. [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).

§1151. Design Pressure of Plastic Fittings [49 CFR 192.191]

A. Thermosetting fittings for plastic pipe must conform to ASTM D 2517. [49 CFR 192.191(a)]

B. Thermoplastic fittings for plastic pipe must conform to ASTM D 2513. [49 CFR 192.191(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 9:226 (April 1983), amended LR 10:518 (July 1984), LR 30:1238 (June 2004).

§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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 13. Welding of Steel in Pipelines [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 in accordance with welding procedures qualified under Section 5 of API 1104 (incorporated by reference, see §507) or section IX of the ASME Boiler and Pressure Vessel Code " Welding and Brazing Qualifications" (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).

§1307. Qualification of Welders [49 CFR 192.227]

A. Except as provided in Subsection B of this Section, each welder must be qualified in accordance with section 6 of API 1104 (incorporated by reference, see §507) or section IX of the ASME Boiler and Pressure Vessel Code (incorporated by reference, see §507) . However, a welder qualified under an earlier edition than listed in §507 may weld but may not requalify 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)]

AUTHORITY 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).

§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. No welder may weld with a particular welding process unless, within the preceding six calendar months, he has engaged in welding with that process. [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 or 9 of API Standard 1104 (incorporated by reference, see §507). Alternatively, welders 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 7½ months. A welder qualified under an earlier edition of a standard listed in §507 of this Subpart may weld but may not requalify under that earlier edition; and [49 CFR 192.229(c)(1)]

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 welders who work only on service lines 2 inches (51 millimeters) or smaller in diameter, 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).

§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 Standard 1104 (incorporated by reference, see §507). However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 applies to the weld, the acceptability of the weld may be further determined under that appendix. . [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).

§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 whose work is isolated from the principal welding activity, a sample of each welder'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).

§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 eight 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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 15. Joining of Materials Other Than by Welding [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 Designation D 2513. [49 CFR 192.281(b)(2)]

3. The joint may not be heated to accelerate the setting of the cement. [49 CFR 192.281(b)(3)]

C. Heat-Fusion Joints. Each heat-fusion joint on plastic pipe must comply with 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, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens. [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 joint uniformly and simultaneously to essentially the same temperature. [49 CFR 192.281(c)(2)]

3. An electrofusion joint must be joined utilizing the equipment and techniques of the fittings' manufacturer or equipment and techniques shown, by testing joints to the requirements of §1513.A.1.c, to be at least equivalent to those of the fittings' 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 Designation D 2517. [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)]

AUTHORITY 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).

§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: [49 CFR 192.283(a)]

1. the burst test requirements of: [49 CFR 192.283(a)(1)]

a. in the case of thermoplastic pipe, Paragraph 6.6 (sustained pressure test) or Paragraph 6.7 (Minimum Hydrostatic Burst Test) or Paragraph 8.9 (Sustained Static pressure Test) of ASTM D2513 (incorporated by reference, see §507); [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(incorporated by reference, see §507); or [49 CFR 192.283(a)(1)(ii)]

c. in the case of electrofusion fittings for polyethylene pipe 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(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; and [49 CFR 192.283(a)(2)]

3. for procedures intended for non-lateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference, see §507), except that the test may be conducted at ambient temperature and humidity If the 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 that are designed to withstand tensile forces, the procedure must be qualified by subjecting five specimen joints made according to the procedure to the following tensile test: [49 CFR 192.283(b)]

1. use an apparatus for the test as specified in ASTM D 638 (except for conditioning), (incorporated by reference, see §507). [49 CFR 192.283(b)(1)]

2. the specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength; [49 CFR 192.283(b)(2)]

3. the speed of testing is 0.20 in. (5.0 mm) per minute, plus or minus 25 percent; [49 CFR 192.283(b)(3)]

4. pipe specimens less than 4 in. (102 mm.) in diameter are qualified if the pipe yields to an elongation of no less than 25 percent or failure initiates outside the joint area; [49 CFR 192.283(b)(4)]

5. pipe specimens 4 in. (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100°F (38°C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress; [49 CFR 192.283(b)(5)]

6. each specimen that fails at the grips must be retested using new pipe; [49 CFR 192.283(b)(6)]

7. results obtained pertain only to the specific outside diameter, and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness. [49 CFR 192.283(b)(7)]

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).

§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 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 requalified under an applicable procedure, if during any 12-month period that person: [49 CFR 192.285(c)]

1. does not make any joints under that procedure; or [49 CFR 192.285(c)(1)]

2. has three joints or 3 percent of the joints made, whichever, is greater, under that procedure that are found unacceptable by testing under §2313. [49 CFR 192.285(c)(2)]

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)]

AUTHORITY 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).

§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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas By Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 17. General Construction Requirements for Transmission Lines and Mains [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. [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 one 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).

§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)]

AUTHORITY 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).

§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 and H 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. Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (2.29 millimeters), except that pipe with an outside diameter of 0.875 inches (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inches (1.58 millimeters). [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. 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)]

AUTHORITY 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)

§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 9:233 (April 1983), amended LR 10:525 (July 1984), LR 20:446 (April 1994), LR 27:1542 (September 2001), LR 30:1247 (June 2004).

§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 Inches (Millimeters)	Consolidated Rock 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 192.324(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.B.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)..

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 19. Customer Meters, Service Regulators, and Service Lines [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; and [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. [49 CFR 192.367(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 9:234 (April 1983), amended LR 10:526 (July 1984), LR 30:1249 (June 2004).

§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; and [49 CFR 192.375(a)(2)(i)]

b. the plastic service line is not used to support external loads. [49 CFR 192.375(a)(2)(ii)]

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.

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§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 to be used on single residence 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).

§1933. Excess Flow Valve Customer Notification [49 CFR 192.383]

A. Definitions. As used in this Section: [49 CFR 192.383(a)]

Costs Associated with Installation--the costs directly connected with installing an excess flow valve; for example, costs of parts, labor, inventory, and procurement. It does not include maintenance and replacement costs until such costs are incurred.

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 Customer--the person who pays the gas bill, or where service has not yet been established, the person requesting the service.

B. Which Customers Must Receive Notification. Notification is required on each newly installed service line or replaced service line that operates continuously throughout the year at a pressure not less than 10 psig (68.9 kPa) and that serves a single residence. On these lines an operator of a natural gas distribution system must notify the service line customer once in writing. [49 CFR 192.383(b)]

C. What to Put in the Written Notice [49 CFR 192.383(c)]

1. An explanation for the customer that an excess flow valve meeting the performance standards prescribed under §1931 is available for the operator to install if the customer bears the costs associated with installation; [49 CFR 192.383(c)(1)]

2. an explanation for the customer of the potential safety benefits that may be derived from installing an excess flow valve. The explanation must include that an excess flow valve is designed to shut off the flow of natural gas automatically if the service line breaks; [49 CFR 192.383(c)(2)]

3. a description of installation, maintenance, and replacement costs. The notice must explain that if the customer requests the operator to install an EFV, the customer bears all costs associated with installation, and what those costs are. 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(c)(3)]

D. When Notification and Installation Must Be Made [49 CFR 192.383(d)]

1. After February 3, 1999 an operator must notify each service line customer set forth in Subsection B of this Section: [49 CFR 192.383(d)(1)]

a. on new service lines when the customer applies for service; [49 CFR 192.383(d)(1)(i)]

b. on replaced service lines when the operator determines the service line will be replaced. [49 CFR 192.383(d)(1)(ii)]

2. If a service line customer requests installation an operator must install the EFV at a mutually agreeable date. [49 CFR 192.383(d)(2)]

E. What Records Are Required [49 CFR 192.383(e)]

1. An 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 192.383(e)(1)]

a. a copy of the notice currently in use; and [49 CFR 192.383(e)(1)(i)]

b. evidence that notice has been sent to the service line customers set forth in Subsection B of this Section, within the previous three years. [49 CFR 192.383(1)(ii)]

F. When Notification Is Not Required. The notification requirements do not apply if the operator can demonstrate: [49 CFR 192.383(f)]

1. that the operator will voluntarily install an excess flow valve or that the state or local jurisdiction requires installation; [49 CFR 192.383(f)(1)]

2. that excess flow valves meeting the performance standards in §1931 are not available to the operator; [49 CFR 192.383(f)(2)]

3. that the operator has prior experience with contaminants in the gas stream that could interfere with the operation of an excess flow valve, cause loss of service to a residence, or interfere with necessary operation or maintenance activities, such as blowing liquids from the line; [49 CFR 192.383(f)(3)]

4. that an emergency or short time notice replacement situation made it impractical for the operator to notify a service line customer before replacing a service line. Examples of these situations would be where an operator has to replace a service line quickly because of: [49 CFR 192.383(f)(4)]

a. third party excavation damage; [49 CFR 192.383(f)(4)(i)]

b. Grade 1 leaks as defined in the Appendix G-192-11 of the Gas Piping Technology Committee guide for gas transmission and distribution systems; [49 CFR 192.383(f)(4)(ii)]

c. a short notice service line relocation request. [49 CFR 192.383(f)(4)(iii)]

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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas By Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 21. Requirements for Corrosion Control [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. Applicability to Converted Pipelines [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; and [49 CFR 192.452(b)(1)]

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. and F 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 eight, 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)]

AUTHORITY 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), LR33:480 (March 2007).

§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. Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding two and one-half months, to insure that it is operating. [49 CFR 192.465(b)]

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 three 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, exposed pipe inspection records, and the pipeline environment. In this Section: [49 CFR 192.465(e)]

1. active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety; [49 CFR 192.465(e)(1)]

2. electrical survey means a series of closely spaced pipe -to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline; [49 CFR 192.465(e)(2)]

3. 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. [49 CFR 192.465(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 9:236 (April 1983), amended LR 10:528 (July 1984), LR 27:1545 (September 2001), LR 30:1253 (June 2004).

§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 residence 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).

§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	At least once every 3 calendar years, but with intervals not exceeding 39 months.
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)]

AUTHORITY 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).

§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 or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). 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).

§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 Chapter 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, except that records related to §2117.A and E and §2127.B must be retained for as long as the pipeline remains in service. [49 CFR 192.491(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 10:530 (July 1984), LR 24:1311 (July 1998), LR 30:1256 (June 2004).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 23. Test Requirements [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)]

AUTHORITY 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).

§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 E 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. 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 the component certifies that: [49 CFR 192.505(d)]

1. the component was tested to at least the pressure required for the pipeline to which it is being added; [49 CFR 192.505(d)(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 192.505(d)(2)]

3. the component carries a pressure rating established through applicable ASME/ANSI, MSS specifications, or by unit strength calculations as described in §1103. [49 CFR 192.505(d)(3)]

E. For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least four hours. [49 CFR 192.505(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 9:238 (April 1983), amended LR 10:530 (July 1984), LR 27:1545 (September 2001), LR 30:1256 (June 2004), LR 31:684 (March 2005).

§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)]

AUTHORITY 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).

§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 three 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).

§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. Each operator shall make, and retain for the useful Life of the pipeline, a record of each test performed under §§2305 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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 27. Operations [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 190.237 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 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).

§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)]

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).

§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 eight hours, 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)]

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)]

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).

§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 7 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 6 months after discovery, or not later than November 1 of the following year if the 6 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)]

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).

§2716. Public Awareness [49 CFR 192.616]

A. 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 (IBR, see §307). [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. [49 CFR 192.616(b)]

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; and [49 CFR 192.616(d)(4)]

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. As an exception, operators of small propane distribution systems having less than 25 customers and master meter operators having less than 25 customers must have completed development and documentation of their programs no later than June 20, 2007. 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)]

AUTHORITY 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).

§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. Except as provided in Subsection C of this Section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds 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; or [49 CFR 192.619(a)(1)(i)]

   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 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: [49 CFR 192.619(a)(2)(ii)]

Factors1, Segment			
Class Location	**Installed before (Nov. 12, 1970)**	**Installed after (Nov. 11, 1970)**	**Converted under CFR §192.14**
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	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.

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

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this subpart (other than §2712) after April 13, 2006. —Onshore transmission line that was a gathering line not subject to this subpart before March 15, 2006.	March 15, 2006, or date line becomes subject to this subpart, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines.	July 1, 1976.	July 1, 1971.
All other pipelines.	July 1, 1970.	July 1, 1965.

4. 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 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)]

AUTHORITY 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), LR33:481 (March 2007).

§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).

§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. Quarterly Reports

1. To assure the proper concentration of odorant in accordance with this Section, each operator 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. Operators of master meter systems 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; 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 calendar quarter;

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).

§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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 29. Maintenance [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).

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

A. 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. As soon as feasible the operator shall make permanent repairs. [49 CFR 192.711(a)(2)]

B. Except as provided in §2917.A.2.c, no operator may use a welded patch as a means of repair. [49 CFR 192.711(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).

§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).

§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 7 1/2 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 www.npms.rspa.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 Information Officer, *Pipeline and Hazardous Materials Safety Administration*, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@dot.gov. 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)]

2. Data on pipeline facilities abandoned before October 10, 2000 must be filed by before April 10, 2001. Operators may submit reports by mail, fax or e-mail to the Information Officer, *Pipeline and Hazardous Materials Safety Administration*, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@dot.gov. 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)(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 10:538 (July 1984), LR 21:824 (August 1995), LR 27:1549 (September 2001), LR 30:1269 (June 2004), LR 33:481 (March 2007).

§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 National Fire Protection Association Standard No. 30. [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).

§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), LR33:482 (March 2007).

§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: Testing 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), LR33:482 (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).

§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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 31. Operator Qualification [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; and [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; and [49 CFR 192.805(h)]

9. After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section. [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).

§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:Promulgatedin 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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 33. Pipeline Integrity Management [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 Subsections (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 subsection 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 subsection a.iii of this definition or subsection 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-2001 (Supplement to ASME B31.8; 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), LR 31:685 (March 2005).

§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), amended 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 §3349, 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 also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the 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).

§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)]

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)]

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)]

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

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

§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; and [49 CFR 192.913(b)(1)(vii)]

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 and outside force damage; 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 evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge

condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation 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 evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment. [49 CFR 192.917(e)(2)]

3. Manufacturing and Construction Defects. If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. 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. operating pressure increases above the maximum operating pressure experienced during the preceding five years; [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. ERW Pipe. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, 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. [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)]

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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 depending on the threats 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 corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see §507), Section 6.2 in selecting the appropriate internal inspection tools for the covered segment; [49 CFR 192.921(a)(1)]

2. pressure test conducted in accordance with Chapter 23 of this Subpart. An operator must use the test pressures specified in Table 3 of Section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §3339. [49 CFR 192.921(a)(2)]

3. direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §3323 and with, as applicable, the requirements specified in §§3325, 3327 or 3329; [49 CFR 192.921(a)(3)]

4. other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §3349. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. [49 CFR 192.921(a)(4)]

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 ten (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)]

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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 (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA). [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. ASME/ANSI B31.8S (ibr, see §507), Section 6.4; NACE RP0502-2002 (ibr, see §507); and §3325 if addressing external corrosion (ECDA); [49 CFR 192.923(b)(1)]

2. ASME/ANSI B31.8S, Section 6.4 and Appendix B2, and §3327 if addressing internal corrosion (ICDA); [49 CFR 192.923(b)(2)]

3. ASME/ANSI B31.8S Appendix A3, and §3329 if addressing stress corrosion cracking (SCCDA). [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 RP 0502-2002 (incorporated by reference, see § 507). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, 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. Preassessment. In addition to the requirements in ASME/ANSI B31.8S Section 6.4 and NACE RP 0502-2002, Section 3, the plan's procedures for preassessment 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 RP0502-2002, 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 Examination. In addition to the requirements in ASME/ANSI B31.8S Section 6.4 and NACE RP 0502-2002, Section 4, the plan's procedures for indirect examination 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 RP 0502-2002, 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 RP0502-2002), 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 RP0502-2002); [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 RP0502-2002. [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 RP 0502-2002, 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 RP0502-2002.) [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(a)(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 Paragraph 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 RP 0502-2002 (ibr, see §507), Section 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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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1281 (June 2004).

§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 that 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 that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment. 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. If pressure is reduced, an operator must determine the temporary reduction in operating pressure using ASME/ANSI B31G (incorporated by reference, see §507) or AGA Pipeline Research Committee Project PR-3-805 [(RSTRENG); incorporated by reference, see §507] or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. (See §507 for information on availability of incorporation by reference information). A reduction in operating pressure cannot exceed 365 days without an operator providing a technical justification that the continued pressure restriction will not jeopardize the integrity of the pipeline. [49 CFR 192.933(a)]

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 that prioritizes 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 justify the reasons why it cannot meet the schedule and that the changed schedule will not jeopardize public safety. An operator must notify OPS in accordance with §3349 if it cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. [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. 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; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in (See §507); [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 & 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 RP-0502-2002 (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, 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, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line. [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% SMYS. An operator of a transmission pipeline operating below 30% 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% 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 the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (see §3317), or by confirmatory direct assessment under the conditions specified in §3331: [49 CFR 192.937(c)]

1. internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see §507), Section 6.2 in selecting the appropriate internal inspection tools for the covered segment; [49 CFR 192.937(c)(1)]

2. pressure test conducted in accordance with Chapter 23 of this Subpart. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §3339. [49 CFR 192.937(c)(2)]

3. direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §3323 and with as applicable, the requirements specified in §§3325, 3327 or 3329; [49 CFR 192.937(c)(3)]

4. other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §3349. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. [49 CFR 192.937(c)(4)]

5. confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §3331. [49 CFR 192.937(c)(5)]

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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% SMYS. An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this Section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-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/ANSI B31.8S, 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 RP0502-2002 (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 years. 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 Subparagraph 1.a of this Section except that the stress level referenced in Clause 1.a.ii would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh 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.

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§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.

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§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)]

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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, on a semi-annual basis, 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), 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, by electronic or other means, on a semi-annual frequency to OPS in accordance with §3351. An operator must submit its first report on overall performance measures by August 31, 2004. Thereafter, the performance measures must be complete through June 30 and December 31 of each year and must be submitted within 2 months after those dates. [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)]

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§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)]

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HISTORICAL NOTE: Promulgated by the Department of Natural Resources, Office of Conservation, Pipeline Division, LR 30:1285 (June 2004).

§3349. How Does an Operator Notify OPS and the Louisiana Commissioner of Conservation? [49 CFR 192.949]

A. An operator must provide any notification required by this Chapter to OPS by: [49 CFR 192.949]

1. sending the notification to the Information Resources Manager, Office of Pipeline Safety, *Pipeline and Hazardous Materials Safety Administration*, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW, Washington DC 20590; [49 CFR 192.949(a)(1)]

2. sending the notification to the Information Resources Manager by facsimile to (202) 366-7128; or [49 CFR 192.949(a)(2)]

3. entering the information directly on the Integrity Management Database (IMDB) web site at http://primis.rspa.dot.gov/gasimp/. [49 CFR 192.949(a)(3)]

B. Any notification required by §3349.A 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).

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

A. An operator must send any performance report required by this Chapter to the Information Resources Manager: [49 CFR 192.951]

1. by mail to the Office of Pipeline Safety, *Pipeline and Hazardous Materials Safety Administration*, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW, Washington, DC 20590; [49 CFR 192.951(1)]

2. via facsimile to (202) 366-7128; or [49 CFR 192.951(2)]

3. through the online reporting system provided by OPS for electronic reporting available at the OPS Home Page at http://ops.dot.gov. [49 CFR 192.951(3)]

B. Any report required by §3351.A 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).

Title 43
NATURAL RESOURCES
Part XIII. Office of Conservation--Pipeline Safety
Subpart 3. Transportation of Natural or Other Gas by Pipeline: Minimum Safety Standards [49 CFR Part 192]
Chapter 51. Appendices

§5101. Appendix A - Reserved

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 10:539 (July 1984), amended LR 18:858 (August 1992), LR 27:1550, 1551 (September 2001), amended LR 30:1286 (June 2004).

§5103. Appendix B--Qualification of Pipe

I. Listed Pipe Specifications

API 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference, see §507)

ASTM A 53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, welded and Seamless"(ibr, see §507)

ASTM A 106—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High temperature Service" (incorporated by reference, see §507)

ASTM A 333/A 333M—Steel pipe, "Standard Specification for Seamless and Welded steel Pipe for Low Temperature Service" (incorporated by reference, see §507)

ASTM A 381—Steel pipe, "Standard specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference, see §507)

ASTM A 671—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference, see §507)

ASTM A 672—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, see §507)

ASTM A 691—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)

ASTM D 2513 "Thermoplastic pipe and tubing, "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see §507)

ASTM D 2517—Thermosetting plastic pipe and tubing, "Standard Specification Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (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), amended LR 30:1287 (June 2004), amended LR 31:689 (March 2005).

§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), amended 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-copper sulfate 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 (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 (refer to figure E.I.A for a diagram of a high consequence area).

Determining High Consequence Area

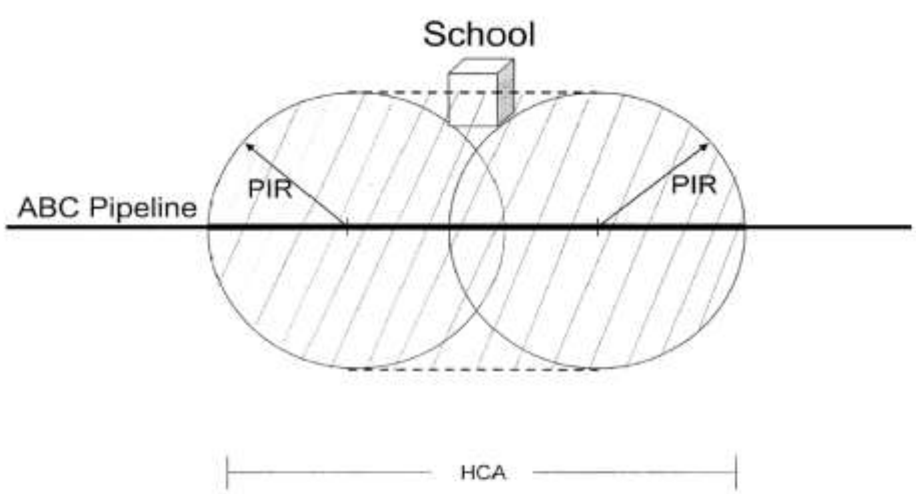

Figure E.I.A

II. Guidance on Assessment Methods for Transmission Pipelines Operating Below 30 percent SMYS

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% 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 & mitigative measures addressing time dependent and independent threats for transmission pipelines that operate below 30% SMYS, in HCAs.

(Column 1) Threat	Existing Subpart 3 Requirements (Column 2) Primary	 (Column 3) Secondary	(Column 4) Additional (to Subpart 3 requirements) Preventive and Mitigative Measures
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 (Repair – gen.) 2917-(Repair – perm.)	2703-(Gen Oper'n) 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 – gen.) 2917-(Repair – perm.)	703(A)-(Materials) 2703-(Gen Oper'n) 2713-(Surveillance)	• Perform semi-annual leak surveys.
3rd Party Damage	903-(Gen. Design), 911-(Design factor) 1717-(Hazard prot), 1727-(Cover)	2715–(Emerg. Plan)	• Participation in state one-call system, • Use of qualified operator employees and contractors to perform marking and locating of

	2714-(Dam. Prevent), 2716-(Public education) 2905-(Patrol), 2907-(Line markers) 2911-(Repair – gen.), 2917-(Repair – perm.)		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.

Table E.II.2 Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment intervals are maximum allowed)						
	Re-Assessment Requirements (see Note 3)					
	At or above 50% SMYS		At or above 30% SMYS up to 50% SMYS		Below 30% SMYS	
Baseline Assessment Method (see Note 3)	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method
Pressure Testing	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	Pressure Test or ILI or DA				
		Repeat inspection cycle every 10 years	15(see Note 1)	Pressure Test or ILI or DA (see Note 1)		
				Repeat inspection cycle every 15 years	20	Pressure Test or ILI or DA
						Repeat inspection cycle every 20 years
In-Line Inspection	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	ILI or DA or Pressure Test				
		Repeat inspection cycle every 10 years	15(see Note 1)	ILI or DA or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	ILI or DA or Pressure Test

						Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	DA or ILI or Pressure Test				
		Repeat inspection cycle every 10 years	15(see Note 1)	DA or ILI or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	DA or ILI or Pressure Test
						Repeat inspection cycle every 20 years
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”					

Table E.II.3

Preventative & Mitigative Measures addressing Time Dependent and Independent Threats for Transmission Pipelines that Operate Below 30% SMYS , in HCAs

Threat	Existing Subpart 3 Requirements		Additional (to Subpart 3 requirements) Preventive & 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-(Repair – gen.) 2917-(Repair – perm.)	2703-(Gen Oper) 2713-(Surveil)	For Cathodically Protected Trmn. Pipelines • Perform an electrical survey (*i.e*. indirect examination tool/method) at least every 7 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 1½ 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-(Repair – gen.) 2917-(Repair – perm.)	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 7 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-(Repair – gen.) 2917-(Repair – perm.)	2715–(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 LR31:690 (March 2005).