John R. Ashcroft

Secretary of State / Administrative Rules

RULE TRANSMITTAL

Administrative Rules Stamp

RECEIVED

By Administrative Rules SOS at 1:42 pm, Mar 19, 2025

RECEIVED JCAR Stamp

By JCAR at 1:14 pm, Mar 19, 2025

Rule Number 20 CSR 4240-40.030

Use a SEPARATE rule transmittal sheet for EACH individual rulemaking.

Name of person(s) Administrative Rules can contact with questions about this rule:

Content Nancy Dippell Phone 573-751-8518 Fax 573-526-6010
Email address Nancy.Dippell@psc.mo.gov

Data Entry Kayla Kliethermes Phone 573-751-4256 Fax 573-526-6010
Email address Kayla.Kliethermes@psc.mo.gov

Interagency mailing address Public Service Commission, 9th Floor Gov. Office Bldg, JC, MO

TYPE OF RULEMAKING ACTION TO BE TAKEN

☐ Emergency Rulemaking > ☐ Rule ☐ Amendment ☐ Rescission ☐ Termination
Effective date for the emergency ______

X Proposed Rulemaking > ☐ Rule ☒ Amendment ☐ Rescission

☐ Rule Action Notice
☐ In Addition
☐ Rule Under Consideration
☐ Request for Non-Substantive Change
☐ Statement of Actual Cost

☐ Order of Rulemaking > ☐ Withdrawal ☐ Adoption ☐ Amendment ☐ Rescission
Effective date for the order ______
☐ Statutory 30 days OR Specific date ______

Does the Order of Rulemaking contain changes to the rule text? ☐ NO
☐ YES—LIST THE SECTIONS/SUBSECTIONS WITH CHANGES:

______

______

Missouri Public Service Commission

MAIDA J. COLEMAN
Commissioner

GLEN KOLKMEYER
Commissioner

KAYLA HAHN
Chair

POST OFFICE BOX 360
JEFFERSON CITY, MISSOURI 65102
573-751-3234
573-751-1847 (Fax Number)
http://psc.mo.gov

VACANT
Commissioner

JOHN P. MITCHELL
Commissioner

March 19, 2025

Denny Hoskins
Secretary of State
Administrative Rules Division
600 West Main Street
Jefferson City, Missouri 65101

Re: 20 CSR 4240-40.030 Safety Standards—Transportation of Gas by Pipeline

Dear Secretary Hoskins,

CERTIFICATION OF ADMINISTRATIVE RULE

I do hereby certify that the attached is an accurate and complete copy of the proposed amendment lawfully submitted by the Missouri Public Service Commission.

The Public Service Commission further certifies it has conducted an analysis of whether or not there has been a taking of real property pursuant to section 536.017, RSMo, that the proposed amendment does not constitute a taking of real property under relevant state and federal law.

The Public Service Commission has determined and hereby also certifies that if the proposed amendment does affect small business pursuant to sections 536.300 to 536.310, RSMo, a small business impact statement has been filed as required by those sections. If no small business impact statement has been filed the proposed amendment either does not affect small business or the small business requirements do not apply pursuant to section 536.300.4, RSMo.

Statutory Authority: *sections 386.250, 386.310, and 393.140, RSMo 2016.*

If there are any questions regarding the content of this proposed amendment, please contact:

Nancy Dippell
Secretary/Chief Regulatory Law Judge
Missouri Public Service Commission
200 Madison Street
P.O. Box 360
Jefferson City, MO 65102
(573) 751-8518
Nancy.Dippell@psc.mo.gov

Nancy Dippell

Nancy Dippell
Secretary

Enclosures

Missouri Public Service Commission

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Commissioner

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VACANT
Commissioner

JOHN P. MITCHELL
Commissioner

March 19, 2025

Sarah Schappe
Director
Joint Committee on Administration Rules
State Capitol, Room B8A
Jefferson City, Missouri 65101

Re: 20 CSR 4240-40.030 Safety Standards—Transportation of Gas by Pipeline

Dear Director Schappe,

CERTIFICATION OF ADMINISTRATIVE RULE

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Statutory Authority: *sections 386.250, 386.310, and 393.140, RSMo 2016.*

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Nancy Dippell

Nancy Dippell
Secretary

Enclosures

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201 W. Capitol Avenue, Room 216
Jefferson City, Missouri 65101

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www.governor.mo.gov

Mike Kehoe
Governor
State of Missouri

March 10, 2025

Kayla Hahn, Chair
Missouri Public Service Commission
P O Box 360
Jefferson City MO 65102

Dear Ms. Hahn:

Our office has received the Proposed Amendment rulemakings for the following regulations:

- **20 CSR 4240-40.30 Safety Standards-Transportation of Gas by Pipeline**

Executive Order 25-13 requires this office's approval before state agencies release proposed regulations for notice and comment, amend existing regulations, or adopt new regulations. After our review, we approve submission of the rule and the regulatory impact report (if required) to JCAR and the Secretary of State.

Sincerely,

Lowell Pearson

Lowell Pearson
General Counsel

AFFIDAVIT

PUBLIC COST

STATE OF MISSOURI)
)
COUNTY OF COLE)

I, Angela L. Nelson, Director of the Department of Commerce and Insurance, first being duly sworn, on my oath, state that it is my opinion that the cost of proposed amendment, 20 CSR 4240-40.030, is less than five hundred dollars in the aggregate to this agency, any other agency of state government or any political subdivision thereof.

Angela L Nelson

Angela L. Nelson
Director
Department of Commerce and Insurance

Subscribed and sworn to before me this 14th day of March, 2025, I am commissioned as a notary public within the County of Callaway, State of Missouri, and my commission expires on May 18, 2028

KIM LANDERS
MY COMMISSION EXPIRES
5-18-2028
NOTARY SEAL
#12558402
CALLAWAY COUNTY
NOTARY PUBLIC, STATE OF MISSOURI

Kim Landers
Notary Public

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Title 20—DEPARTMENT OF COMMERCE AND INSURANCE
Division 4240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

20 CSR 4240-40.030 Safety Standards—Transportation of Gas by Pipeline. The Public Service Commission proposes amending sections (1), (2), (3), (4), (5), (6), (7), (8), (9), (10), (11), (12), (13), (14), (15), (16), (17), and Appendix B.

PURPOSE: This amendment modifies the rule to address amendments of 49 CFR part 192 promulgated between January 2023 and July 2024, address technical corrections published in the Federal Register on June 28, 2024, pages 89 FR 53877 and 89 FR 53880, address corrections to conform to judicial review published in the Federal Register on January 15, 2025, page 90 FR 3713, and make clarification and editorial changes.

(1) General.
(A) What Is the Scope of this Rule? (192.1)
1. This rule prescribes minimum safety requirements for pipeline facilities and the transportation of gas in Missouri and under the jurisdiction of the commission. A table of contents is provided in Appendix E, which is included herein (at the end of this rule).
2. This rule does not apply to—
A. The gathering of gas—
(I) Through a pipeline that operates at less than zero (0) pounds per square inch gauge (psig) (0 kPa); or
(II) Through a pipeline that is not a regulated onshore gathering line (as determined in (1)(E)**1.**); or
B. Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—
(I) Fewer than ten (10) customers, if no portion of the system is located in a public place; or
(II) 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).
(B) Definitions. (192.3) As used in this rule—
1. Abandoned means permanently removed from service;
2. Active corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety;
3. Administrator means the Administrator of the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation to whom authority in the matters of pipeline safety have been delegated by the Secretary of the United States Department of Transportation, or his or her delegate;
4. Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters;
5. Building means any structure that is regularly or periodically occupied by people;
6. Close interval survey means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for

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the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey;

7. Commission means the Missouri Public Service Commission;

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

9. Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility;

10. Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a supervisory control and data acquisition (SCADA) system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility;

11. Customer meter means the meter that measures the transfer of gas from an operator to a consumer;

12. Designated commission personnel means the pipeline safety program manager at the address contained in 20 CSR 4240-40.020(5)(E) for correspondence;

13. Distribution center means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example—

A. At a metering location;

B. A pressure reduction location; or

C. Where there is a reduction in the volume of gas, such as a lateral off a transmission line;

14. Distribution line means a pipeline other than a gathering or transmission line;

15. Dry gas or dry natural gas means gas above its dew point and without condensed liquids;

16. Electrical survey means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline, except that other indirect examination tools/methods can be used for an electrical survey included in the federal regulations in 49 CFR part 192, subpart O and appendix E (incorporated by reference in section (16));

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

18. Entirely replaced transmission pipeline segments means, for the purposes of subsections (4)(U) and (12)(X), where two (2) or more miles, in the aggregate, of transmission pipeline have been replaced within any five (5) contiguous miles of pipeline within any twenty-four- (24-) month period. This definition does not apply to any gathering line;

19. Feeder line means a distribution line that has a maximum allowable operating pressure (MAOP) greater than 100 psi (689 kPa) gauge that produces hoop stresses less than twenty percent (20%) of specified minimum yield strength (SMYS);

20. Follow-up inspection means an inspection performed after a repair procedure has been completed in order to determine the effectiveness of the repair and to ensure that all hazardous leaks in the area are corrected;

21. Fuel line means the customer-owned gas piping downstream from the outlet of the customer meter or operator-owned pipeline, whichever is farther downstream;
22. Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;
23. Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main;
24. Hard spot means an area on steel pipe material with a minimum dimension greater than two inches (2") (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV10);
25. High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than an equivalent to fourteen inches (14") water column;
26. Hoop stress means the stress in a pipe wall acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe produced by the pressure in the pipe;
27. In-line inspection (ILI) means an inspection of a pipeline from the interior of the pipe using an inspection tool also called intelligent or smart pigging. This definition includes tethered and self-propelled inspection tools;
28. In-line inspection tool or instrumented internal inspection device means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an intelligent or smart pig;
29. Listed specification means a specification listed in subsection I. of Appendix B, which is included herein (at the end of this rule);
30. Low-pressure distribution system means a distribution system in which the gas pressure in the main is less than or equal to an equivalent of fourteen inches (14") water column;
31. Main means a distribution line that serves as a common source of supply for more than one (1) service line;
32. Master Meter System means a pipeline system for distributing gas within, but not limited to, a definable area (such as a mobile home park, housing project, or apartment complex) where the operator purchases metered gas from an outside source for resale through a gas distribution 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 by rents.
[*32*]**33**. Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of one (1) year;
[*33*]**34**. Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this rule;
[*34*]**35**. Moderate consequence area means—
A. An onshore area that is within a “potential impact circle” as defined in 49 CFR 192.903 (incorporated by reference in section (16)), containing either—
(I) Five (5) or more buildings intended for human occupancy; or
(II) Any portion of the paved surface (including shoulders) of a designated “interstate,” “other freeway or expressway,” as well as any “other principal arterial” roadway with four (4) or more lanes, as defined in the Federal Highway Administration’s Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1 (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classificatio

ns/fcauab.pdf), and that does not meet the definition of "high consequence area" in 49 CFR 192.903 (incorporated by reference in section (16)); and

B. The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either five (5) or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with four (4) or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either five (5) or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with four (4) or more lanes;

[*35*]**36**. Municipality means a city, village, or town;

[*36*]**37**. Notification of potential rupture means the notification to, or observation by, an operator of indicia identified in subsection (12)(Y) of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline. This definition does not apply to any gathering line;

[*37*]**38**. Operator means a person who engages in the transportation of gas;

[*38*]**39**. Person means any individual, firm, joint venture, partnership, corporation, association, county, state, municipality, political subdivision, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative of them;

[*39*]**40**. Petroleum gas means 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 (1434 kPa) gauge at 100°F (38°C);

[*40*]**41**. PHMSA means the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation;

[*41*]**42**. Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders;

[*42*]**43**. Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies;

[*43*]**44**. 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;

[*44*]**45**. Pipeline facility means 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;

[*45*]**46**. Reading means the highest sustained reading when testing in a bar hole or opening without induced ventilation;

[*46*]**47**. Rupture-mitigation valve (RMV) means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture. This definition does not apply to any gathering line;

[*47*]**48**. Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two (2) 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;

[*48*]**49**. Service regulator means 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 (1) customer or multiple customers through a meter header or manifold;

[*49*]**50**. SMYS means 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 paragraph (3)(D)2. [*(192.107(b))*];

[*50*]**51**. Supervisory control and data acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility;

[*51*]**52**. Sustained reading means the reading taken on a combustible gas indicator unit after adequately venting the test hole or opening;

[*52*]**53**. Transmission line means a pipeline or connected series of pipelines, other than a gathering line, that—

A. Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center (A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.);

B. Has an MAOP of twenty percent (20%) or more of SMYS;

C. Transports gas within a storage field; or

D. Is voluntarily designated by the operator as a transmission pipeline;

[*53*]**54**. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting intrastate, interstate, or foreign commerce;

[*54*]**55**. Tunnel means a subsurface passageway large enough for a man to enter;

[*55*]**56**. Vault or manhole means a subsurface structure that a man can enter;

[*56*]**57**. Weak link means a device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed;

[*57*]**58**. Welder means a person who performs manual or semi-automatic welding;

[*58*]**59**. Welding operator means a person who operates machine or automatic welding equipment;

[*59*]**60**. Wrinkle bend means a bend in the pipe that—

A. Was formed in the field during construction such that the inside radius of the bend has one or more ripples with—

(I) An amplitude greater than or equal to one and one-half (1.5) times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(II) With ripples less than one and one-half (1.5) times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under twelve (12); and

B. If the length of the wrinkle bend cannot be reliably determined, then wrinkle bend means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds (47,000-S)/10,000 + 1 for psi [(324-S)/69 + 1 for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more. Where—

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

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

(III) S = Maximum operating hoop stress, psi (S/145, MPa); and

[*60*]**61**. Yard line means an underground fuel line that transports gas from the service line to the customer's building. If multiple buildings are being served, building means the building nearest to the connection to the service line. For purposes of this definition, if aboveground fuel line piping at the meter location is located within five feet (5') of a building being served by that meter, it will be considered to the customer's building and no yard line exists. At meter locations where aboveground fuel line piping is located greater than five feet (5') from the building(s) being served, the underground fuel line from the meter to the entrance into the nearest building served by that meter will be considered the yard line and any other lines are not considered yard lines.

(D) Incorporation By Reference of the Federal Regulation at 49 CFR 192.7. (192.7)

1. As set forth in the Code of Federal Regulations (CFR) dated October 1, [*2021*]**2023**, and the subsequent amendment 192-[*132*]**135** (published in Federal Register on [*August 24, 2022*]**April 29, 2024**, page [*87*]**89** FR [*52224*]**33264**), the federal regulation at 49 CFR 192.7 is incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR 192.7.

2. The Code of Federal Regulations and the Federal Register are published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, [*2021*]**2023**, version of 49 CFR part 192 is available at [*https://www.govinfo.gov/#citation*]**https://www.govinfo.gov/content/pkg/CFR-2023-title49-vol3/pdf/CFR-2023-title49-vol3-part192.pdf**. The Federal Register publication on page [*87*]**89** FR [*52224*]**33264** is available at [*https://www.govinfo.gov/content/pkg/FR-2022-08-24/pdf/2022-17031.pdf*] **https://www.govinfo.gov/content/pkg/FR-2024-04-29/pdf/2024-08624.pdf**.

3. The regulation at 49 CFR 192.7 provides a listing of the documents that are incorporated by reference partly or wholly in 49 CFR part 192, which is the federal counterpart and foundation for this rule. All incorporated materials are available for inspection from several sources, including the following sources:

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

B. The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, go to the NARA website at www.archives.gov/federal-register/cfr/ibr-locations.html or call 202-741-6030 or 866-272-6272; and

C. Copies of standards incorporated by reference can also be purchased or are otherwise made available from the respective standards-developing organizations listed in 49 CFR 192.7.

4. Federal amendment 192-94 (published in Federal Register on June 14, 2004, page 69 FR 32886) moved the listing of incorporated documents to 49 CFR 192.7 from 49 CFR part 192−Appendix A, which is now "Reserved." This listing of documents was in Appendix A to this rule prior to the 2008 amendment of this rule. As of the 2008 amendment, Appendix A to this rule is also "Reserved" and included herein.

(E) Gathering Lines.

1. How are Gathering Pipelines and Regulated Gathering Pipelines Determined? (192.8)

A. An operator must use API RP 80 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)), to determine if a pipeline (or part of a connected series of pipelines) is a gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the gathering line is a regulated gathering line under paragraph (1)(E)1.

(I) 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.’’

(II) 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.

(III) 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 fifty (50) miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR 190.9).

(IV) 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.

(V) For new, replaced, relocated, or otherwise changed gas gathering pipelines installed after May 16, 2022, the endpoint of gathering under sections 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80—also known as ‘‘incidental gathering’’—may not be used if the pipeline terminates ten (10) or more miles downstream from the furthermost downstream endpoint as defined in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 and this paragraph. If an ‘‘incidental gathering’’ pipeline is ten (10) miles or more in length, the entire portion of the pipeline that is designated as an incidental gathering line under 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 shall be classified as a transmission pipeline subject to rules 20 CSR 4240-40.020, 20 CSR 4240-40.030, 20 CSR 4240-40.033, and 20 CSR 4240-40.080.

B. Each operator must determine and maintain for the life of the pipeline records documenting the methodology by which it calculated the beginning and end points of each gathering pipeline it operates, as described in the second column of table 1 to part (1)(E)1.C.(II), by—

(I) November 16, 2022, or before the pipeline is placed into operation, whichever is later; or

(II) An alternative deadline approved by the Pipeline and Hazardous Materials Safety Administration (PHMSA). The operator must notify PHMSA and designated commission personnel no later than ninety (90) days in advance of the deadline in part (1)(E)1.B.(I). The notification must be made in accordance with subsection (1)(M) and must include the following information:

(a) Description of the affected facilities and operating environment;

(b) Justification for an alternative compliance deadline; and

(c) Proposed alternative deadline.

C. For purposes of 20 CSR 4240-40.020 and paragraph (1)(E)2., the term ‘‘regulated gathering pipeline’’ means—

(I) Each Type A, Type B, or Type C gathering pipeline (or segment of gathering pipeline) with a feature described in the second column of table 1 to part (1)(E)1.C.(II) that lies in an area described in the third column; and

(II) As applicable, additional lengths of pipeline described in the fourth column to provide a safety buffer.

Table 1 to Part (1)(E)1.C.(II)

Type	Feature	Area	Safety Buffer
A	• Metallic and the MAOP produces a hoop stress of twenty percent (20%) or more of SMYS. • If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in section (3). • Non-metallic and the MAOP is more than one hundred twenty-five (125) psig (862 kPa).	Class 2, 3, or 4 location (see subsection (1)(C)).	None.
B	• Metallic and the MAOP produces a hoop stress of less than twenty percent (20%) of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in section (3). • Non-metallic and the MAOP is one hundred twenty-five (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 one hundred fifty feet (150') (45.7 m) on each side of the centerline of any continuous one (1) mile (1.6 km) of pipeline and including more than ten (10) but fewer than forty-six (46) dwellings; or (c) An area extending one hundred fifty feet (150') (45.7 m) on each side of the centerline of any continuous one	If the gathering pipeline 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 one hundred fifty feet (150') (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 pipeline as Type B, the Type B classification ends one hundred fifty feet (150') (45.7 m) from the nearest dwelling in the cluster.

		thousand feet (1000') (305 m) of pipeline and including five (5) or more dwellings.	
C	• Outside diameter greater than or equal to 8.625 inches and any of the following: – Metallic and the MAOP produces a hoop stress of twenty percent (20%) or more of SMYS; – If the stress level is unknown, segment is metallic and the MAOP is more than one hundred twenty-five (125) psig (862 kPa); or – Non-metallic and the MAOP is more than one hundred twenty- five (125) psig (862 kPa).	Class 1 location.	None.
R	All other gathering lines.	Class 1 and Class 2 locations.	None.

(III) A Type R gathering line is subject to reporting requirements under 20 CSR 4240-40.020 but is not a regulated gathering line under this rule.

(IV) For the purpose of identifying Type C lines in table 1 to part (1)(E)1.C.(II), if an operator has not calculated MAOP consistent with the methods at paragraph (12)(M)1. or subparagraph (12)(M)3.A., the operator must either—

(a) Calculate MAOP consistent with the methods at paragraph (12)(M)1. or subparagraph (12)(M)3.A.; or

(b) Use as a substitute for MAOP the highest operating pressure to which the segment was subjected during the preceding five (5) operating years.

2. What Requirements Apply to Gathering Pipelines? (192.9)

A. Requirements. An operator of a gathering line must follow the safety requirements of this rule as prescribed by this paragraph.

B. Type A lines. An operator of a Type A regulated gathering line must comply with the requirements of this rule applicable to transmission lines, except the requirements in (1)(G)4., (4)(HH), (6)(H)5., (7)(J)3.–6., (9)(G)6.–9., (9)(I)4. and 6., (9)(M)3., (9)(S)3., (9)(X), [*(9)(Y),*] (10)(K), (12)(E), (12)(H)3., (12)(M)5., (12)(U), (13)(DD), (13)(EE), (13)(GG), and section (16)—Pipeline Integrity Management for Transmission Lines (Subpart O). However, an operator of a Type A regulated gathering line in a Class 2 location may demonstrate compliance with subsection (12)(D) by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks. Further, operators of Type A regulated gathering lines are exempt from the requirements of (4)(U)4.–6., (12)(W), (12)(L)2.–4., (12)(X), (12)(Y), (12)(Z), and (13)(U)3.**-6.** Lastly, operators of Type A regulated gathering lines are exempt from the requirements of subsection (12)(J) (but an operator of a Type A regulated gathering line must comply with the requirements of subsection (12)(J), effective February 28, 2023).

C. Type B lines. An operator of a Type B regulated gathering line must comply with the following requirements:

(I) 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 rule applicable to transmission lines. Compliance with (2)(G), (3)(M), (4)(U)4. and 5., (4)(II), (5)(D)3., (6)(H)5., (7)(J)3.–6., (10)(K), (12)(X), and (12)(Z) is not required;

(II) If the pipeline is metallic, control corrosion according to requirements of section (9) applicable to transmission lines, except the requirements in (9)(G)6.–9., (9)(I)4. and 6., (9)(M)3., (9)(S)3., **and** (9)(X)[*, and (9)(Y)*];

(III) If the pipeline contains plastic pipe or components, the operator must comply with all applicable requirements of this rule for plastic pipe components;

(IV) Carry out a damage prevention program under subsection (12)(I);

(V) Establish a public education program under subsection (12)(K);

(VI) Establish the MAOP of the line under paragraphs (12)(M)1., 2., and 3.;

(VII) Install and maintain line markers according to the requirements for transmission lines in subsection (13)(E); and

(VIII) Conduct leakage surveys in accordance with the requirements for transmission lines in subsection (13)(D), using leak-detection equipment, and promptly repair hazardous leaks in accordance with paragraph (13)(B)3.

D. Type C lines. The requirements for Type C gathering lines are as follows:

(I) An operator of a Type C gathering line with an outside diameter greater than or equal to eight and five-eighths inches (8.625") must comply with the following requirements:

(a) Except as provided in subparagraph (1)(E)2.G. for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in sections (2)–(7) and (10) applicable to transmission lines. Compliance with (2)(G), (3)(M), (4)(U)4. and 5., (4)(II), (5)(D)3., (6)(H)5., (7)(J)3.–6., (10)(K), (12)(X), and (12)(Z) is not required;

(b) If the pipeline is metallic, control corrosion according to requirements of section (9) applicable to transmission lines, except the requirements in (9)(G)6.–9., (9)(I)4. and 6., (9)(M)3., (9)(S)3., **and** (9)(X)[*, and (9)(Y)*];

(c) Carry out a damage prevention program under subsection (12)(I);

(d) Develop and implement procedures for emergency plans in accordance with the requirements of subsection (12)(J), effective February 28, 2023;

(e) Develop and implement a written public awareness program in accordance with subsection (12)(K);

(f) Install and maintain line markers according to the requirements for transmission lines in subsection (13)(E); and

(g) Conduct leakage surveys in accordance with the requirements for transmission lines in subsection (13)(D) using leak-detection equipment, and promptly repair hazardous leaks in accordance with paragraph (13)(B)3.; and

(II) An operator of a Type C gathering line with an outside diameter greater than twelve and three-quarters inches (12.75") must comply with the requirements in part (1)(E)2.D.(I) and the following:

(a) If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this rule for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and

(b) Establish the MAOP of the pipeline under paragraph (12)(M)1. or 3. and maintain records used to establish the MAOP for the life of the pipeline.

E. Exceptions.

(I) Compliance with subparts (1)(E)2.D.(I)(b), (e), (f), and (g) and subparts (1)(E)2.D.(II)(a) and (b) is not required for pipeline segments that are sixteen inches (16") or less in outside diameter if one (1) of the following criteria are met:

(a) Method 1. The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in 49 CFR 192.903 (incorporated by reference in section (16)), except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with subpart (1)(E)2.D.(II)(b); and

(b) Method 2. The segment is not located within a class location unit (see subsection (1)(C)) containing a building intended for human occupancy or other impacted site.

(II) Subpart (1)(E)2.D.(I)(a) is not applicable to pipeline segments forty feet (40') or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022.

(III) For purposes of this paragraph, the term ‘‘building intended for human occupancy or other impacted site’’ means any of the following:

(a) Any building that may be occupied by humans, including homes, office buildings, factories, outside recreation areas, plant facilities, etc.;

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

(c) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with four (4) or more lanes.

F. Compliance deadlines. An operator of a regulated gathering line must comply with the following deadlines, as applicable.

(I) An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this paragraph by the date the line goes into service, unless an exception in subsection (1)(G) applies.

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

Requirement	Compliance Deadline
(i) Control corrosion according to requirements for transmission lines in section (9).	April 15, 2009.
(ii) Carry out a damage prevention program under subsection (12)(I).	October 15, 2007.
(iii) Establish MAOP under subsection (12)(M).	October 15, 2007.
(iv) Install and maintain line markers under subsection (13)(E).	April 15, 2008.
(v) Establish a public education program under subsection (12)(K).	April 15, 2008.
(vi) Other provisions of this rule as required by subparagraph (1)(E)2.B. for Type A lines.	April 15, 2009.

(III) If, after April 14, 2006, a change in class location or increase in dwelling density causes a gathering pipeline to become a Type A or Type B regulated gathering line, the operator has one (1) year for Type B lines and two (2) years for Type A lines after the pipeline becomes a regulated gathering pipeline to comply with this paragraph.

(IV) If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this rule, an operator must comply with the applicable requirements of this paragraph, except for subparagraph (1)(E)2.G., on or before—

(a) May 16, 2023; or

(b) An alternative deadline approved by PHMSA. The operator must notify PHMSA and designated commission personnel no later than ninety (90) days in advance of the deadline in part (1)(E)1.B.(I). The notification must be made in accordance with subsection (1)(M) and must include a description of the affected facilities and operating environment, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities.

(V) If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline, or causes a Type C gathering pipeline to become subject to additional Type C requirements (see subparagraph (1)(E)2.E.), the operator has one (1) year after the pipeline becomes subject to the additional requirements to comply with this paragraph.

G. Composite materials. Pipe and components made with composite materials not otherwise authorized for use under this rule may be used on Type C gathering pipelines if the following requirements are met:

(I) Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in sections (2)–(7) and (10) applicable to transmission lines;

(II) Operators must notify PHMSA in accordance with subsection (1)(M) at least ninety (90) days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this rule in a Type C gathering pipeline. The notifications required by this paragraph must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including—

(a) The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and states in which it is located;

(b) A general description of the right-of-way including high consequence areas, as defined in 49 CFR 192.905 (incorporated by reference in section (16));

(c) Relevant pipeline design and construction information including the year of installation, the specific composite material, diameter, wall thickness, and any manufacturing and construction specifications for the pipeline;

(d) Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results;

(e) An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks;

(f) An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained;

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

(h) An explanation of how the use of composite pipeline material would be in the public interest; and

(i) A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety; and

(III) Repairs or replacements using materials authorized under this rule do not require notification under this paragraph.

(F) Petroleum Gas Systems. (192.11)

1. Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this rule and [*of*] NFPA 58 [*and*]**or** NFPA 59 (**both** incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**, based on the scope and applicability statements in those standards**.

2. Each pipeline system subject to this rule that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this rule and [*of*] NFPA 58 [*and*]**or** NFPA 59 (**both** incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**, based on the scope and applicability statements in those standards**.

3. In the event of a conflict between this rule and NFPA 58 [*and*]**or** NFPA 59 (**both** incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), NFPA 58 [*and*]**or**

NFPA 59 **shall** prevail **if applicable based on the scope and applicability statements in those standards**.

(G) What General Requirements Apply to Pipelines Regulated Under this Rule? (192.13)

1. 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—

A. The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this rule; or

B. The pipeline qualifies for use under this rule in accordance with subsection (1)(H). [*(192.14)*]

Pipeline	Date
Regulated onshore gathering pipeline to which this rule did not apply until April 14, 2006 (see (1)(E))	March 15, 2007
Regulated onshore gathering pipeline to which this rule did not apply until May 16, 2022 (see (1)(E))	May 16, 2023
All other pipelines	March 12, 1971

2. 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 that replacement, relocation, or change has been made according to the requirements in this rule.

Pipeline	Date
Regulated onshore gathering pipeline to which this rule did not apply until April 14, 2006 (see (1)(E))	March 15, 2007
Regulated onshore gathering pipeline to which this rule did not apply until May 16, 2022 (see (1)(E))	May 16, 2023
All other pipelines	November 12, 1970

3. Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this rule.

4. Each operator of a gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. Each operator of a gas transmission pipeline must develop and follow a management of change process, as outlined in ASME[*/ANSI*] B31.8S, section 11 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must

include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. For pipeline segments other than those covered in section (16)—Pipeline Integrity Management for Transmission Lines (Subpart O), this management of change process must be implemented by February 26, 2024. The requirements of this paragraph do not apply to gas gathering pipelines. Operators may request an extension of up to one (1) year by submitting a notification to PHMSA at least ninety (90) days before February 26, 2024, in accordance with subsection (1)(M). The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this subsection, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

5. This section and sections (9) and (11)–(17) apply regardless of installation date. The requirements within other sections of this rule apply regardless of the installation date only when specifically stated as such.

(2) Materials.

(B) General. (192.53)

1. Materials for pipe and components must be *[–]***:**

*[1]***A**. Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

*[2]***B**. Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact;

*[3]***C**. Qualified in accordance with the applicable requirements of this section; **and**

*[4]***D**. Only of steel or polyethylene for pipe for the underground construction of pipelines, except**:** *[that other previously]*

(I) Previously qualified materials may be used for repair of pipe constructed of the same material; and

(II) Composite materials as defined in subsection (1)(B) may be used for pipe in Type C gathering lines when permitted by paragraph (1)(E)2. and subject to prior notifications to PHMSA and designated commission personnel in accordance with paragraph (1)(E)2. and subsection (1)(M).

*[5]***2**. Other piping materials may be used with approval of the commission.

(G) Records: Material Properties. (192.67)

1. For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with subsections (2)(B) and (2)(C) [*(192.53 and 192.55)*]. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

2. For steel transmission pipelines installed on or before July 1, 2020, if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in

accordance with subsections (2)(B) and (2)(C) [*(192.53 and 192.55)*], operators must retain such records for the life of the pipeline.

3. For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of subsection (12)(U) [*(192.624)*] according to the terms of that subsection.

(3) Pipe Design.

(C) Design Formula for Steel Pipe. (192.105)

1. The design pressure for steel pipe is determined in accordance with the following formula:

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

where—

P = Design pressure in pounds per square inch (kPa) gauge;

S = Yield strength in pounds per square inch (kPa) determined in accordance with subsection (3)(D); [*(192.107)*]

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 subsection (3)(E) [*(192.109)*]. Additional wall thickness required for concurrent external loads in accordance with subsection (3)(B) [*(192.103)*] may not be included in computing design pressure;

F = Design factor determined in accordance with subsection (3)(F) [*(192.111)*];

E = Longitudinal joint factor determined in accordance with subsection (3)(G) [*(192.113)*]; and

T = Temperature derating factor determined in accordance with subsection (3)(H) [*(192.115)*].

2. 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 seventy-five percent (75%) of the pressure determined under paragraph (3)(C)1. 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 (1) hour.

(D) Yield Strength (S) for Steel Pipe. (192.107)

1. For pipe that is manufactured in accordance with a specification listed in subsection I of Appendix B, the yield strength to be used in the design formula in subsection (3)(C) [*(192.105)*] is the SMYS stated in the listed specification, if that value is known.

2. For pipe that is manufactured in accordance with a specification not listed in subsection I of Appendix B or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in subsection (3)(C) [*(192.105)*] is one (1) of the following:

A. If the pipe is tensile tested in accordance with paragraph II-D of Appendix B, the lower of the following:

(I) Eighty percent (80%) of the average yield strength determined by the tensile tests; or

(II) The lowest yield strength determined by the tensile tests; or

B. If the pipe is not tensile tested as provided in subparagraph (3)(D)2.A., twenty-four thousand (24,000) psi (165 MPa).

(E) Nominal Wall Thickness (t) for Steel Pipe. (192.109)

1. 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.

2. However, if the pipe is of uniform grade, size, and thickness and there are more than ten (10) lengths, only ten percent (10%) of the individual lengths, but not less than ten (10) lengths, need to 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 subsection (3)(C) [*(192.105)*] 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 one and fourteen hundredths (1.14) times the smallest measurement taken on pipe less than twenty inches (20”) (508 millimeters) in outside diameter, nor more than one and eleven hundredths (1.11) times the smallest measurement taken on pipe twenty inches (20”) (508 millimeters) or more in outside diameter.

(F) Design Factor (F) for Steel Pipe. (192.111)

1. Except as otherwise provided in paragraphs (3)(F)2.–4., the design factor to be used in the design formula in subsection (3)(C) [*(192.105)*] is determined in accordance with the following table:

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

2. A design factor of 0.60 or less must be used in the design formula in subsection (3)(C) [*(192.105)*] for steel pipe in Class 1 locations that—

A. Crosses the right-of-way of an unimproved public road without a casing;

B. 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;

C. Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

D. Is used in a fabricated assembly (including separators, mainline valve assemblies, cross-connections and river crossing headers) or is used within five (5) 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.

3. For Class 2 locations, a design factor of 0.50 or less must be used in the design formula in subsection (3)(C) [*(192.105)*] for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

4. For Class 1 and Class 2 locations, a design factor of 0.50 or less must be used in the design formula in subsection (3)(C) [*(192.105)*] for—

A. Steel pipe in a compressor station, regulating station or measuring station; and

B. Steel pipe, including a pipe riser, on a platform located in inland navigable waters.

(G) Longitudinal Joint Factor (E) for Steel Pipe. (192.113)

1. The longitudinal joint factor to be used in the design formula in subsection (3)(C) is determined in accordance with the [*following*] table **1 to this paragraph (3)(G)1.**:

Table 1 to Paragraph (3)(G)1.

Specification	**Pipe Class**	**Longitudinal Joint Factor (E)**

ASTM A53/A53M **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.60
ASTM A106 **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**	Seamless	1.00
ASTM A333/A333M **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**	Seamless	1.00
	Electric resistance welded	1.00
ASTM A381 **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**	Double submerged arc welded	1.00
ASTM A671 **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**	Electric fusion welded	1.00
ASTM A672 **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**	Electric fusion welded	1.00
ASTM A691 **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**	Electric fusion welded	1.00
API 5L **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	0.60
Other	Pipe over 4 inches (102 millimeters)	0.80
Other	Pipe 4 inches (102 millimeters) or less	0.60

2. If the type of longitudinal joint cannot be determined, the joint factor to be used must not exceed that designated for **"**Other**"**.

(H) Temperature Derating Factor (T) for Steel Pipe. (192.115) The temperature derating factor to be used in the design formula in subsection (3)(C) [*(192.105)*] is determined as follows:

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

450 °F (232 °C)	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

(I) Design of Plastic Pipe. (192.121)

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

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

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

where

P = Design pressure, psi (kPa) gauge;

S = For thermoplastic pipe, the hydrostatic design base (HDB) is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2. of PPI TR–3/2008, HDB/PDB/SDB/MRS Policies (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

t = Specified wall thickness, inches (millimeters);

D = Specified outside diameter, inches (millimeters); and

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

DF = Design Factor, a maximum of 0.32 unless otherwise specified for a particular material in this subsection.

2. General Requirements for Plastic Pipe and Components.

A. The design pressure may not exceed a gauge pressure of 100 psi (689 kPa) gauge for plastic pipe.

B. Plastic pipe may not be used where operating temperatures of the pipe will be—

(I) 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

(II) Above the temperature at which the HDB used in the design formula under this subsection is determined.

C. The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

D. All plastic pipe must have a listed HDB in accordance with PPI TR–4/2012 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. Polyethylene (PE) Pipe Requirements.

A. The federal regulation at 49 CFR 192.121(c)(1) is not adopted in this rule. (This federal regulation permits higher design pressures for certain types of PE pipe.)

B. For PE pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided—

(I) The design pressure does not exceed 100 psig;

(II) The material designation code is PE2708 or PE4710;

(III) The pipe has a nominal size (IPS or CTS) of 24 inches or less; and

(IV) The wall thickness for a given outside diameter is not less than that listed in [*the following*] [*t*]Table **1 to this part (3)(I)3.B.(IV)**:

Table 1 to Part (3)(I)3.B.(IV)

PE Pipe: Minimum Wall Thickness and SDR Values		
Pipe Size (inches)	Minimum wall thickness (inches)	Corresponding [*SDR*]**dimension ratio** (values)
½" CTS	0.090	7
[*¾" CTS*]**½" IPS**	0.090	[*9.7*]**9.3**
[*½" IPS*]**¾" CTS**	0.090	[*9.3*]**9.7**
¾" IPS	0.095	11
1" CTS	0.099	11
1" IPS	0.119	11
1 ¼" CTS	**0.121**	**11**
1 ¼" IPS	0.151	11
1 ½" IPS	0.173	11
2"	0.216	11
3"	0.259	13.5
4"	0.265	17
6"	0.315	21
8"	0.411	21
10"	0.512	21
12"	0.607	21
16"	0.762	21
18"	0.857	21
20"	0.952	21
22"	1.048	21
24"	1.143	21

4. The federal regulations at 49 CFR 192.121(d) through (f) are not adopted in this rule. (Those federal regulations address design requirements for types of plastic pipe other than PE pipe.)

(M) Records: Pipe Design. (192.127)

1. For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with subsection (3)(B) [*(192.103)*] and documenting that the determination of design pressure for the pipe is made in accordance with subsection (3)(C) [*(192.105)*].

2. For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with subsections (3)(B) and (3)(C) [*(192.103 and 192.105)*], operators must retain such records for the life of the pipeline.

3. For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may

be subject to the requirements of subsection (12)(U) [*(192.624)*] according to the terms of that subsection.

(4) Design of Pipeline Components.

(D) Valves. (192.145)

1. Except for cast iron and plastic valves, each valve must meet the minimum requirements of [*ANSI/*]API Specification 6D (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), 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.

2. Each cast iron and plastic valve must comply with the following:

A. The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature; and

B. The valve must be tested as part of the manufacturing, as follows:

(I) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least one and one-half (1.5) times the maximum service rating;

(II) After the shell test, the seat must be tested to a pressure not less than one and one-half (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; and

(III) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.

3. Each valve must be able to meet the anticipated operating conditions.

4. No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding eighty percent (80%) 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 eighty percent (80%) of the pressure ratings for comparable steel valves at their listed temperature, if —

A. The temperature-adjusted service pressure does not exceed 1,000 psi (7 MPa) gauge; and

B. Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.

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

6. Except for excess flow valves, plastic valves installed after April 22, 2019, must meet the minimum requirements of a listed specification. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification.

(E) Flanges and Flange Accessories. (192.147)

1. Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5 **(incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)),** [*and*] **ANSI/**MSS SP–44 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), or the equivalent.

2. 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.

3. Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face, and gasket design to ASME/ANSI B16.1 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) and be cast integrally with the pipe, valve, or fitting.

(H) Components Fabricated by Welding. (192.153)

1. Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the *ASME Boiler and Pressure Vessel Code* (Section VIII, Division 1) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

2. Each prefabricated unit that uses plate and longitudinal seams must be designated, constructed, and tested in accordance with the *ASME Boiler and Pressure Vessel Code* (*Rules for Construction of Pressure Vessels* as defined in either Section VIII, Division 1 or 2) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), except for the following:

A. Regularly manufactured butt-welding fittings;

B. Pipe that has been produced and tested under a specification listed in Appendix B to this rule;

C. Partial assemblies such as split rings or collars; and

D. 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.

3. Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of twenty percent (20%) or more of the SMYS of the pipe.

4. Except for flat closures designed in accordance with [*the*] *ASME Boiler and Pressure Vessel Code***,** [*(*]Section VIII, Division 1 or **Division** 2[*)*]**,** (**both** incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), flat closures and fish tails may not be used on pipe that either operates at 100 psi**g** (689 [*kPa*]**kilopascals**) [*gauge*] or more, or **that** is more than three inches (3") (76 millimeters) **in** nominal diameter.

5. The test requirements for a prefabricated unit or pressure vessel, defined for this paragraph as components with a design pressure established in accordance with paragraph (4)(H)1. or 2., are as follows:

A. A prefabricated unit or pressure vessel installed after July 14, 2004, is not subject to the strength testing requirements of paragraph (10)(C)2. provided the component has been tested in accordance with paragraph (4)(H)1. or 2. and with a test factor of at least 1.3 times MAOP;

B. A prefabricated unit or pressure vessel must be tested for a duration specified as follows:

(I) A prefabricated unit or pressure vessel installed after July 14, 2004, but before October 1, 2021, is exempt from paragraphs (10)(C)3. and 4. and paragraph (10)(D)3. provided it has been tested for a duration consistent with the ASME BPVC requirements referenced in paragraph (4)(H)1. or 2; and

(II) A prefabricated unit or pressure vessel installed on or after October 1, 2021, must be tested for the duration specified in either paragraph (10)(C)3. or 4., (10)(D)3., or (10)(E)1., whichever is applicable for the pipeline in which the component is being installed;

C. For any prefabricated unit or pressure vessel permanently or temporarily installed on a pipeline facility, an operator must either—

(I) Test the prefabricated unit or pressure vessel in accordance with this subsection and section (10) after it has been placed on its support structure at its final installation location. The test may be performed before or after it has been tied-in to the pipeline. Test records that meet paragraph (10)(I)1. must be kept for the operational life of the prefabricated unit or pressure vessel; or

(II) For a prefabricated unit or pressure vessel that is pressure tested prior to installation or where a manufacturer's pressure test is used in accordance with paragraph (4)(H)5., inspect the prefabricated unit or pressure vessel after it has been placed on its support structure at its final installation location and confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection procedure and documented inspection must include visual inspection for vessel damage, including, at a minimum, inlets, outlets, and lifting locations. Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. This inspection must be performed prior to operation but may be performed either before or after it has been tied-in to the pipeline. If injurious defects that are an integrity threat are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with the applicable requirements in this rule for a fabricated unit or with the applicable ASME BPVC requirements referenced in paragraphs (4)(H)1. or 2. Test, inspection, and repair records for the fabricated unit or pressure vessel must be kept for the operational life of the component. Test records must meet the requirements in paragraph (10)(I)1.;

D. An initial pressure test from the prefabricated unit or pressure vessel manufacturer may be used to meet the requirements of this subsection with the following conditions:

(I) The prefabricated unit or pressure vessel is newly-manufactured and installed on or after October 1, 2021, except as provided in part (4)(H)5.D.(II);

(II) An initial pressure test from the fabricated unit or pressure vessel manufacturer or other prior test of a new or existing prefabricated unit or pressure vessel may be used for a component that is temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. The temporary component must be promptly removed after that task is completed. If operational and environmental constraints require leaving a temporary prefabricated unit or pressure vessel under this paragraph in place for longer than thirty (30) days, the operator must notify PHMSA and designated commission personnel in accordance with subsection (1)(M);

(III) The manufacturer's pressure test must meet the minimum requirements of this rule; and

(IV) The operator inspects and remediates the prefabricated unit or pressure vessel after installation in accordance with part (4)(H)5.C.(II);

E. An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement, and then reinstalled at the same location must be inspected in accordance with part (4)(H)5.C.(II); however, a new pressure test is not required provided no damage or threats to the operational integrity of the prefabricated unit or pressure vessel were identified during the inspection and the MAOP of the pipeline is not increased; and

F. Except as provided in part (4)(H)5.D.(II) and subparagraph (4)(H)5.E., on or after October 1, 2021, an existing prefabricated unit or pressure vessel relocated and operated at a different location must meet the requirements of this rule and the following:

(I) The prefabricated unit or pressure vessel must be designed and constructed in accordance with the requirements of this rule at the time the vessel is returned to operational service at the new location; and

(II) The prefabricated unit or pressure vessel must be pressure tested by the operator in accordance with the testing and inspection requirements of this rule applicable to newly installed prefabricated units and pressure vessels.

(M) Compressor Stations—Design and Construction. (192.163)

1. Location of compressor building. Except for a compressor building on a platform located 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 firefighting equipment.

2. Building construction. Each building on a compressor station site must be made of noncombustible materials if it contains either—

A. Pipe more than two inches (2”) (51 millimeters) in diameter that is carrying gas under pressure; or

B. Gas handling equipment other than gas utilization equipment used for domestic purposes.

3. Exits. Each operating floor of a main compressor building must have at least two (2) 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.

4. Fenced areas. Each fence around a compressor station must have at least two (2) 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 two hundred feet (200’) (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

5. Electrical facilities. Electrical equipment and wiring installed in compressor stations must conform to [*NFPA-70*]**NFPA 70** (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), so far as that code is applicable.

(S) Pipe-Type and Bottle-Type Holders. (192.175)

1. 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.

2. Each pipe-type or bottle-type holder must have a minimum clearance from other holders in accordance with the following formula:

$$C = (3D \times P \times F)/1000 \text{ (in inches)}$$

$$(C=(3D\times P\times F) / 6{,}895) \text{ (in millimeters)}$$

where

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) gauge; and

F = Design factor as set forth in subsection (3)(F) [*(192.111)*].

(T) Additional Provisions for Bottle-Type Holders. (192.177)

1. Each bottle-type holder must be—

A. Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum Allowable Operating Pressure	**Minimum Clearance feet (meters)**
Less than 1000 psi (7 MPa) gauge	25 (7.6)
1000 psi (7 MPa) gauge or more	100 (31)

B. Designed using the design factors set forth in subsection (3)(F) [*(192.111)*]; and

C. Buried with a minimum cover in accordance with subsection (7)(N). [*(192.327)*]

2. Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

A. A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/A372M (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

B. The actual yield-tensile ratio of the steel may not exceed 0.85;

C. 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;

D. The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to eighty-five percent (85%) of the SMYS; and

E. The holder, connection pipe, and components must be leak tested after installation as required by section (10).

(CC) Protection Against Accidental Overpressuring. (192.195)

1. General requirements. Except as provided in subsection (4)(DD) [*(192.197)*], 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 subsections (4)(EE) and (FF). [*(192.199 and 192.201)*]

2. Additional requirements for distributions 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—

A. 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

B. Be designed so as to prevent accidental overpressuring.

(II) Records: Pipeline Components. (192.205)

1. For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and

pressure rating to which each valve was manufactured and tested in accordance with this section. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of forty-two thousand (42,000) psi (X42) or greater and with nominal diameters of greater than two inches (2") must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.

2. For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of forty-two thousand (42,000) psi (X42) or greater and with nominal diameters of greater than two inches (2"), operators must retain such records for the life of the pipeline.

3. For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of subsection (12)(U) [*(192.624)*] according to the terms of that subsection.

(5) Welding of Steel in Pipelines.

(B) General.

1. Welding is only to be performed in accordance with established written welding procedures that have been qualified under subsection (5)(C) [*(192.225)*] to produce sound, ductile welds.

2. Welding is only to be performed by welders who are qualified under subsections (5)(D) and (E) [*(192.227 and 192.229)*] for the welding procedure to be used.

(C) Welding Procedures. (192.225)

1. Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5 **(except for Note 2 in section 5.4.2.2)**, section 12, Appendix A, or Appendix B of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) or section IX of the ASME Boiler and Pressure Vessel Code (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) to produce welds meeting the requirements of section (5) of this rule. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the referenced welding standard(s).

2. 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.

(E) Limitations on Welders and Welding Operators. (192.229)

1. No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station pipe and components.

2. A welder or welding operator may not weld with a particular welding process unless, within the preceding six (6) calendar months, the welder or welding operator was engaged in welding with that process. Alternatively, welders or welding operators may demonstrate they have engaged in a specific welding process if they have performed a weld with that process that was tested and found acceptable under section 6, section 9, section 12, or Appendix A of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) within the preceding seven and one-half (7 1/2) months.

3. A welder or welding operator qualified under paragraph (5)(D)1. [*(192.227(a))*]—

A. May not weld on pipe to be operated at a pressure that produces a hoop stress of twenty percent (20%) or more of SMYS unless within the preceding six (6) calendar months the welder or welding operator has had one (1) weld tested and found acceptable under section 6, section 9, section 12, or Appendix A of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding seven and one-half (7 1/2) months. A welder or welding operator qualified under an earlier edition of a standard listed in 49 CFR 192.7 (see subsection (1)(D)) may weld, but may not requalify under that earlier edition; and

B. May not weld on pipe to be operated at a pressure that produces a hoop stress of less than twenty percent (20%) of SMYS unless the welder or welding operator is tested in accordance with subparagraph (5)(E)3.A. or requalifies under subparagraph (5)(E)4.A. or B.

4. A welder or welding operator qualified under paragraph (5)(D)2. may not weld unless—

A. Within the preceding fifteen (15) calendar months, but at least once each calendar year, the welder or welding operator has requalified under paragraph (5)(D)2.; or

B. Within the preceding seven and one-half (7 1/2) calendar months, but at least twice each calendar year, the welder or welding operator has had—

(I) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(II) For a welder who works only on service lines two inches (2") (51 millimeters) or smaller in diameter, two (2) sample welds tested and found acceptable in accordance with the test in subsection III. of Appendix C to this rule.

(J) Nondestructive Testing. (192.243)

1. Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate the defects that may affect the integrity of the weld.

2. Nondestructive testing of welds must be performed—

A. In accordance with written procedures; and

B. By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

3. Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under paragraph (5)(I)3. [*(192.241[c])*].

4. When nondestructive testing is required under paragraph (5)(I)2. [*(192.241[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:

A. In Class 1 locations, at least ten percent (10%);

B. In Class 2 locations, at least fifteen percent (15%);

C. In Class 3 and Class 4 locations, at crossings of major or navigable rivers and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, one hundred percent (100%) unless impracticable, in which case at least ninety percent (90%). Nondestructive testing must be impracticable for each girth weld not tested; and

D. At pipeline tie-ins, including tie-ins of replacement sections, one hundred percent (100%).

5. Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder or welding operator's work for each day must be nondestructively tested, when that testing is required under paragraph (5)(I)2. [*(192.241[b])*].

6. When nondestructive testing is required under paragraph (5)(I)2. [*(192.241[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.

(K) Repair or Removal of Defects. (192.245)

1. Each weld that is unacceptable under paragraph (5)(I)3. [*(192.241[c])*] must be removed or repaired. A weld must be removed if it has a crack that is more than eight percent (8%) of the weld length.

2. 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.

3. 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 subsection (5)(C) [*(192.225)*]. 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.

(6) Joining of Materials Other Than by Welding.

(E) Copper Pipe. (192.279) Copper pipe may not be threaded[,] except that copper pipe used for joining screw fittings or valves**, which** 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*]**ASME B36.10M (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**.

(H) Plastic Pipe—Qualifying Persons to Make Joints. (192.285)

1. No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by—

A. Appropriate training or experience in the use of the procedure; and

B. Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (6)(H)2.

2. The specimen joint must be—

A. 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

B. In the case of a heat fusion, solvent cement, or adhesive joint—

(I) Tested under any one (1) of the test methods listed under paragraph (6)(G)1. [*(192.283(a))*], and for polyethylene heat fusion joints (except for electrofusion joints) visually inspected in accordance with ASTM F2620 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), or a written procedure that has been demonstrated to provide an equivalent or superior level of safety, applicable to the type of joint and material being tested;

(II) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(III) Cut into at least three (3) longitudinal straps, each of which is—

(a) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(b) Deformed by bending, torque, or impact and, if failure occurs, it must not initiate in the joint area.

3. A person must be requalified under an applicable procedure once each calendar year at intervals not exceeding fifteen (15) months, or after any production joint is found unacceptable by testing under subsection (10)(G). [*(192.513)*]

4. 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 subsection.

5. For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of five (5) years following construction.

(I) Plastic Pipe—Inspection of Joints. (192.287) No person may carry out the inspection of joints in plastic pipes required by paragraphs (6)(B)3. and (6)(H)2. [*(192.273[c] and 192.285[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.

(7) General Construction Requirements for Transmission Lines and Mains.

(G) Bends and Elbows. (192.313)

1. Each field bend in steel pipe, other than a wrinkle bend made in accordance with subsection (7)(H) [*(192.315)*], must comply with the following:

A. A bend must not impair the serviceability of the pipe;

B. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage; and

C. On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless—

(I) The bend is made with an internal bending mandrel; or

(II) The pipe is twelve inches (12") (305 millimeters) or less in outside diameter or has a diameter-to-wall thickness ratio less than seventy (70).

2. 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.

3. Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is two inches (2") (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least one inch (1") (25 millimeters).

4. An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.

(M) Underground Clearance. (192.325)

1. Each transmission line must be installed with at least twelve inches (12") (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.

2. 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.

3. In addition to meeting the requirements of paragraph (7)(M)1. or 2., 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.

4. Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in paragraph (4)(S)2. [*(192.175[b])*]

(8) Customer Meters, Service Regulators, and Service Lines.

(B) Service Lines and Yard Lines.

1. All service line installations and residential/small commercial yard line replacements made after December 15, 1989, must be installed, owned, operated, and maintained by the operator regardless of meter location. Installations of customer-owned service lines and residential/small commercial yard lines, as defined in (1)(B) [*(192.3)*], will not be permitted. If the customer meter is not located within five feet (5') of the building wall, the service line to the customer's nearest building shall be installed, owned, operated, and maintained by the operator. Installation and maintenance may be performed by representatives approved by the operator and the operator must assure that the work performed by approved representatives is in compliance with the requirements of this rule.

2. Yard lines for large commercial/industrial customers may be installed or replaced, owned, and maintained, except for leak surveys, by the customer, provided the new yard line is cathodically protected, coated steel, or polyethylene pipe and the operator's installation standards are met.

(K) Service Lines—Connections to Cast Iron or Ductile Iron Mains. (192.369)

1. 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 subsection (6)(B). [*(192.273)*]

2. If a threaded tap is being inserted, the requirements of paragraphs (4)(G)2. and 3. [*(192.151[b] and [c])*] must also be met.

(M) Service Lines—Plastic. (192.375)

1. Each plastic service line outside a building must be installed below ground level, except that—

A. It may be installed in accordance with paragraph (7)(K)7.; and

B. It may terminate aboveground level and outside the building, if—

(I) The aboveground level part of the plastic service line is protected against deterioration and external damage;

(II) The plastic service line is not used to support external loads; and

(III) The riser portion of the service line meets the design requirements of (4)(AA).

2. Plastic service lines shall not be installed inside a building.

3. Plastic pipe that is installed in a below grade vault or pit must be completely encased in gastight metal pipe and fittings that are adequately protected from corrosion.

4. Plastic pipe must be installed so as to minimize shear or tensile stresses.

5. Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (0.090"), except that pipe with an outside diameter of 0.875 inches (0.875") or less may have a minimum wall thickness of 0.062 inches (0.062").

6. 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.

7. For requirements pertaining to installation of plastic service lines by trenchless excavation, see subsection (8)(R). [*(192.376)*]

(Q) Manual Service Line Shut-Off Valve Installation (192.385)

1. Definitions for subsection (8)(Q). Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

2. Installation requirement. The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH**, where replaced service line is defined in paragraph (8)(P)1**.

3. Accessibility and maintenance. Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this subsection are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification.

(9) Requirements for Corrosion Control.

(B) How Does this Section Apply to Converted Pipelines and Regulated Onshore Gathering Lines? (192.452)

1. Converted pipelines. Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this rule in accordance with subsection (1)(H) must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with subsection (9)(H) within one (1) year after the pipeline is readied for service.

2. Type A and B onshore gathering lines. For any Type A and B onshore gathering line under [*49 CFR 192.9*]**paragraph (1)(E)2.** existing on April 14, 2006, that was not previously subject to this [*part*]**rule**, and for any gathering line that becomes a regulated onshore gathering line under [*subsection*]**paragraph** (1)(E)**2.** [*of this rule (192.9)*] after April 14, 2006, because of a change in class location or increase in dwelling density—

A. The requirements of this section specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

B. The requirements of this section specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

3. Type C onshore regulated gathering lines. For any Type C onshore regulated gathering pipeline under [*subsection*]**paragraph** (1)(E)**2.** [*of this rule (192.9)*] existing on May 16, 2022, that was not previously subject to this rule, and for any Type C onshore gas gathering pipeline that becomes subject to section (9) after May 16, 2022, because of an increase in MAOP, change

in class location, or presence of a building intended for human occupancy or other impacted site—

A. The requirements of section (9) specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

B. The requirements of section (9) specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

4. Regulated onshore gathering lines generally. Any gathering line that is subject to section (9) per [*subsection*]**paragraph** (1)(E)**2. [***of this rule*] or 49 CFR 192.9 at the time of construction must meet the requirements of section (9) applicable to pipelines installed after July 31, 1971.

(D) External Corrosion Control—Buried or Submerged Pipelines Installed After July 31, 1971. (192.455)

1. Except as provided in paragraphs (9)(D)2., 5., and 6., each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

A. It must have an external protective coating meeting the requirements of subsection (9)(G) [*(192.461)*]; and

B. It must have a cathodic protection system designed to protect the pipeline in accordance with this section, installed and placed in operation within one (1) year after completion of construction.

2. An operator need not comply with paragraph (9)(D)1., if the operator can demonstrate by tests, investigation, or experience that—

A. For a copper pipeline, a corrosive environment does not exist; or

B. For a temporary pipeline with an operating period of service not to exceed five (5) years beyond installation, corrosion during the five- (5-) year period of service of the pipeline will not be detrimental to public safety.

3. Notwithstanding the provisions of paragraph (9)(D)2., if a pipeline is externally coated, it must be cathodically protected in accordance with subparagraph (9)(D)1.B.

4. 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 (8), unless tests or experience indicate its suitability in the particular environment involved.

5. This subsection does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if—

A. 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

B. The fitting is designed to prevent leaking caused by localized corrosion pitting.

6. Electrically isolated metal alloy fittings installed after April 22, 2019, that do not meet the requirements of paragraph (9)(D)5. must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.

(F) External Corrosion Control—Inspection of Buried Pipeline When Exposed. (192.459) Whenever an operator has knowledge that any portion of a buried metallic pipeline is exposed, an inspection of the exposed portion must be conducted. If the pipe is coated, the condition of the coating must be determined. If the pipe is bare or if the coating is deteriorated, the surface of the pipe must be examined for evidence of external corrosion. If external corrosion requiring remedial action under subsections (9)(R) through (9)(U) [*(192.483 through 192.489)*] 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.

(I) External Corrosion Control—Monitoring and Remediation. (192.465)

1. Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding fifteen (15) months, to determine whether the cathodic protection meets the requirements of subsection (9)(H) of this rule. [*(192.463)*] However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of one hundred feet (100') (thirty meters (30 m)), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least twenty percent (20%) of these protected structures, distributed over the entire system, must be surveyed each calendar year, with a different twenty percent (20%) checked each subsequent year, so that the entire system is tested in each five- (5-) year period. Each short section of metallic pipe less than one hundred feet (100’) (thirty meters (30 m)) in length installed and cathodically protected in accordance with paragraph (9)(R)2. of this rule [*(192.483(b))*], each segment of pipe cathodically protected in accordance with paragraph (9)(R)3. of this rule [*(192.483(c))*] and each electrically isolated metallic fitting not meeting the requirements of paragraph (9)(D)5. of this rule [*(192.455(f))*] must be monitored at a minimum rate of ten percent (10%) each calendar year, with a different ten percent (10%) checked each subsequent year, so that the entire system is tested every ten (10) years.

2. Cathodic protection rectifiers and impressed current power sources must be periodically inspected as follows:

A. Each cathodic protection rectifier or other impressed current power source must be inspected six (6) times each calendar year, but with intervals not exceeding two and one-half (2 1/2) months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier; and

B. After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding fifteen (15) months.

3. Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six (6) times each calendar year, but with intervals not exceeding two and one-half (2 1/2) months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding fifteen (15) months.

4. Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (9)(I)1.–3. Corrective measures must be completed within six (6) months unless otherwise approved by designated commission personnel. For gas transmission pipelines, no extension for corrective measures may exceed the earliest of the following:

A. Prior to the next inspection or test interval required by this subsection;

B. Within one (1) year, not to exceed fifteen (15) months, of the inspection or test that identified the deficiency; or

C. As soon as practicable, not to exceed six (6) months, after obtaining any necessary permits. Permits necessary to complete corrective actions must be applied for within six (6) months of completing the inspection or testing that identified the deficiency.

5. After the initial evaluation required by paragraphs (9)(D)2. and (9)(E)2., each operator must, not less than every three (3) years at intervals not exceeding thirty-nine (39) months, reevaluate its unprotected pipelines and cathodically protect them in accordance with section (9) in areas in which active corrosion is found. Unprotected steel service lines are subject to replacement pursuant to subsection (15)(C). The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, the pipeline environment, and by instrument leak detection surveys (see subsections (13)(D) and (13)(M)). When the operator conducts electrical surveys, the operator must demonstrate that the surveys effectively identify areas of active corrosion.

6. An operator must determine the extent of the area with inadequate cathodic protection for gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in Appendix D.

A. Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.

B. To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately five feet (5') or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this subsection with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (9)(I)4. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

(N) Internal Corrosion Control—General and Monitoring. (192.475 and 192.477)

1. 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.

2. Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found—

A. The adjacent pipe must be investigated to determine the extent of internal corrosion;

B. Replacement must be made to the extent required by the applicable paragraphs of subsections (9)(S), (T), or (U) [*(192.485, 192.487, or 192.489)*]; and

C. Steps must be taken to minimize the internal corrosion.

3. Gas containing more than 0.25 grain of hydrogen sulfide per one hundred (100) cubic feet (5.8 milligrams/m^3) at standard conditions (four (4) parts per million) may not be stored in pipe-type or bottle-type holders.

4. Monitoring. (192.477) 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 (2) times each calendar year, but with intervals not exceeding seven and one-half (7 1/2) months.

(R) Remedial Measures—General. (192.483)

1. 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 subsection (9)(G). [*(192.461)*]

2. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected and monitored in accordance with this section.

3. 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 and monitored in accordance with this section.

(Y) [*Internal Corrosion Control—Transmission Monitoring and Mitigation. (192.478)*

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

2. The monitoring and mitigation program described in subsection (9)(Y) must include—

A. The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents;

B. Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects; and

C. An evaluation at least once each calendar year, at intervals not to exceed fifteen (15) months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

3. An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed fifteen (15) months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.]***Reserved.***

(10) Test Requirements.

(B) General Requirements. (192.503)

1. No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

A. It has been tested in accordance with this section and subsection (12)(M) [*(192.619)*] to substantiate the maximum allowable operating pressure; and

B. Each potentially hazardous leak has been located and eliminated.

2. The test medium must be liquid, air, natural gas, or inert gas that is—

A. Compatible with the material of which the pipeline is constructed;

B. Relatively free of sedimentary materials; and

C. Except for natural gas, nonflammable.

3. Except as provided in paragraph (10)(C)1. *[(192.505[a])]*, if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

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

4. Each connection used to tie-in a test segment of pipeline is excepted from the specific test requirements of this section, but it must be leak tested at not less than its operating pressure.

5. 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—

A. The component was tested to at least the pressure required for the pipeline to which it is being added;

B. 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

C. The component carries a pressure rating established through applicable ASME/ANSI specifications, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in subsection (4)(B).

(I) Records. (192.517)

1. For pipelines other than service lines, each operator shall make and retain for the useful life of the pipeline, a record of each test performed under subsections (10)(C)–(E), (G), and (K). [*(192.505, 192.506, 192.507, 192.509, and 192.513)*] Where applicable to the test performed, the record must contain at least the following information, except as noted in subparagraph (10)(I)1.B.:

A. The operator’s name, the name of the operator’s employee responsible for making the test, and the name of any test company used;

B. Test medium used, except for tests performed pursuant to subsections (10)(E) and (G);

C. Test pressure;

D. Test duration;

E. Pressure recording charts or other record of pressure readings;

F. Elevation variations, whenever significant for the particular test;

G. Leaks and failures noted and their disposition;

H. Test date; and

I. Description of facilities being tested.

2. For service lines, each operator shall make and retain for the useful life of the pipeline, a record of each test performed under subsections (10)(F) and (G) [*(192.511 and 192.513)*]. Where applicable to the test performed, the record must contain the test pressure, **test duration,** leaks, and failures noted and their disposition and the date.

3. Each operator shall make and retain for the useful life of the pipeline, a record of each test performed under paragraph (10)(B)4.

(K) Transmission Lines: Spike Hydrostatic Pressure Test. (192.506)

1. Spike test requirements. Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of thirty percent (30%) or more of SMYS is spike tested under this rule, the spike hydrostatic pressure test must be conducted in accordance with this subsection.

A. The test must use water as the test medium.

B. The baseline test pressure must be as specified in subparagraph (12)(M)1.B. [*(192.619(a)(2))*].

C. The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least eight (8) hours as specified in subsection (10)(C) [*(192.505)*].

D. After the test pressure stabilizes at the baseline pressure and within the first two (2) hours of the eight- (8-) hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or one-hundred percent (100%) SMYS. This spike hydrostatic pressure test must be held for at least fifteen (15) minutes after the spike test pressure stabilizes.

2. "Other technology" or other technical evaluation process. Operators may use "other technology" or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA ninety (90) days in advance of the assessment or reassessment requirements of this chapter. The notification must be made in accordance with subsection (1)(M) [*(192.18)*] and must include the following information:

A. Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;

B. Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;

C. Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;

D. Assessment techniques and acceptance criteria;

E. Remediation methods for assessment findings;

F. Spike hydrostatic pressure test monitoring and acceptance procedures, if used;

G. Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and

H. Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

(11) Uprating.

(B) General Requirements. (192.553)

1. Pressure increases. Whenever the requirements of this section 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:

A. 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. When a combustible gas is being used for uprating, all buried piping must be checked with a leak detection instrument after each incremental increase; and

B. 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.

2. 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 section, of all work performed, and of each pressure test conducted, in connection with the uprating.

3. Written plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure compliance with each applicable requirement of this section.

4. Limitation on increase in maximum allowable operating pressure. Except as provided in (11)(C)3., a new maximum allowable operating pressure established under this section may not exceed the maximum that would be allowed under subsections (12)(M) and (12)(N) 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 in subsection (3)(C) is unknown, the MAOP may be increased as provided in subparagraph (12)(M)1.A.

5. Establishment of a new maximum allowable operating pressure. Subsections (12)(M) and (N) [*(192.619 and 192.621)*] must be reviewed when establishing a new MAOP. The pressure to which the pipeline is raised during the uprating procedure is the test pressure that must be divided by the appropriate factors in subparagraph (12)(M)1.B. [*(192.619[a][2])*] except that pressure tests conducted on steel and plastic pipelines after July 1, 1965 are applicable.

(C) Uprating to a Pressure That Will Produce a Hoop Stress of Thirty Percent (30%) or More of SMYS in Steel Pipelines. (192.555)

1. Unless the requirements of this subsection have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of thirty percent (30%) or more of SMYS and that is above the established maximum allowable operating pressure.

2. Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall—

A. 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 rule; and

B. Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.

3. After complying with paragraph (11)(C)2., 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 subsection (12)(M) [*(192.619)*], 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).

4. After complying with paragraph (11)(C)2., an operator that does not qualify under paragraph (11)(C)3. may increase the previously established maximum allowable operating pressure if at least one (1) of the following requirements is met:

A. The segment of pipeline is successfully tested in accordance with the requirements of this rule for a new line of the same material in the same location; or

B. 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—

(I) It is impractical to test it in accordance with the requirements of this rule;

(II) The new maximum operating pressure does not exceed eighty percent (80%) of that allowed for a new line of the same design in the same location; and

(III) 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 rule.

5. Where a segment of pipeline is uprated in accordance with paragraph (11)(C)3. or subparagraph (11)(C)4.B., the increase in pressure must be made in increments that are equal to—

A. Ten percent (10%) of the pressure before the uprating; or

B. Twenty-five percent (25%) of the total pressure increase, whichever produces the fewer number of increments.

(12) Operations.

(B) General Provisions. (192.603)

1. No person may operate a segment of pipeline unless it is operated in accordance with this section.

2. Each operator shall keep records necessary to administer the procedures established under subsection (12)(C). [*(192.605)*]

3. Each operator is responsible for ensuring that all work completed on its pipelines by its consultants and contractors complies with this rule.

4. Designated commission personnel may require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety. In the event of a dispute between designated commission personnel and the operator with respect to the appropriateness of a required amendment, the operator may file with the commission a request for a hearing before the commission, or the designated commission personnel may request that a complaint be filed against the operator by the general counsel of the commission.

(C) Procedural Manual for Operations, Maintenance, and Emergencies. (192.605)

1. 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 that are not exempt under subparagraph (12)(C)3.E., the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding fifteen (15) months, but at least once each calendar year. This manual must be prepared before initial operations of a pipeline system commence and appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

2. Maintenance and normal operations. The manual required by paragraph (12)(C)1. must include procedures for the following, if applicable, to provide safety during maintenance and normal operations:

A. Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this section and sections (13) and (14);

B. Controlling corrosion in accordance with the operations and maintenance requirements of section (9);

C. Making construction records, maps, and operating history available to appropriate operating personnel;

D. Gathering of data needed for reporting incidents under 20 CSR 4240-40.020 in a timely and effective manner;

E. Starting up and shutting down any part of a pipeline in a manner designed to assure operation within the MAOP limits prescribed by this rule, plus the build-up allowed for operation of pressure limiting and control devices;

F. Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service;

G. Starting, operating, and shutting down gas compressor units;

H. 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;

I. Inspecting periodically to ensure that operating pressures are appropriate for the class location;

J. 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;

K. Systematically and routinely testing and inspecting pipe-type or bottle-type holders including:

(I) Provision for detecting external corrosion before the strength of the container has been impaired;

(II) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas that, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(III) Periodic inspection and testing of pressure limiting equipment to determine that it is in a safe operating condition and has adequate capacity;

L. Continuing observations during all routine activities including, but not limited to, meter reading and cathodic protection work, for the purpose of detecting potential leaks by observing vegetation and odors. Potential leak indications must be recorded and responded to in accordance with section (14);

M. Testing and inspecting of customer-owned gas piping and equipment in accordance with subsection (12)(S);

N. Responding promptly to a report of a gas odor inside or near a building, unless the operator’s emergency procedures under subparagraph (12)(J)1.C. specifically apply to these reports; and

O. Implementing the applicable control room management procedures required by subsection (12)(T).

3. Abnormal operation. For transmission lines the manual required by paragraph (12)(C)1. must include procedures for the following to provide safety when operating design limits have been exceeded:

A. Responding to, investigating, and correcting the cause of—

(I) Unintended closure of valves or shutdowns;

(II) Increase or decrease in pressure or flow rate outside normal operating limits;

(III) Loss of communications;

(IV) Operation of any safety device; and

(V) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property;

B. Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation;

C. Notifying responsible operator personnel when notice of an abnormal operation is received;

D. 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; and

E. The requirements of this paragraph (12)(C)3. do not apply to natural gas distribution operations that are operating transmission lines in connection with their distribution system.

4. Safety-related conditions. The manual required by paragraph (12)(C)1. 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 commission's reporting requirements.

5. Surveillance, emergency response, and accident investigation. The procedures required by paragraph (12)(H)1. and subsections (12)(J) and (L) [*(192.613[a], 192.615 and 192.617)*] must be included in the manual required by paragraph (12)(C)1.

(D) Qualification of Pipeline Personnel.

1. Scope. (192.801)

A. This subsection prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility. This subsection applies to all individuals who perform covered tasks, regardless of whether they are employed by the operator, a contractor, a subcontractor, or any other entity performing covered tasks on behalf of the operator.

B. For the purpose of this subsection, a covered task is an activity, identified by the operator, that—

(I) Is performed on a pipeline facility;

(II) Is an operations, maintenance, or emergency-response task;

(III) Is performed as a requirement of this rule; and

(IV) Affects the operation or integrity of the pipeline.

2. Definitions. (192.803)

A. Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(I) Indicate a condition exceeding design limits;

(II) Result in a hazard(s) to persons, property, or the environment; or

(III) Require an emergency response.

B. Evaluation (or evaluate) means a process consisting of training and examination, established and documented by the operator, to determine an individual's ability to perform a covered task and to demonstrate that an individual possesses the knowledge and skills under paragraph (12)(D)4. After initial evaluation for paragraph (12)(D)4., subsequent evaluations for paragraph (12)(D)4. can consist of examination only. The examination portion of this process may be conducted by one (1) or more of the following:

(I) Written examination;

(II) Oral examination;

(III) Hands-on examination, which could involve observation supplemented by appropriate queries. Observations can be made during:

(a) Performance on the job;

(b) On the job training; or

(c) Simulations.

C. Qualified means that an individual has been evaluated and can:

(I) Perform assigned covered tasks; and

(II) Recognize and react to abnormal operating conditions.

3. Qualification program. (192.805) Each operator shall have and follow a written qualification program. The program shall include provisions to:

A. Identify covered tasks;

B. 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;

C. Ensure through evaluation that individuals performing covered tasks are qualified and have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities;

D. Allow individuals that are not qualified pursuant to this subsection to perform a covered task if directed and observed by an individual that is qualified;

E. Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident meeting the Missouri reporting requirements in 20 CSR 4240-40.020(4)(A);

F. Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

G. Communicate changes, including changes to rules and procedures, that affect covered tasks to individuals performing those covered tasks and their supervisors, and incorporate those changes in subsequent evaluations;

H. Identify the interval for each covered task at which evaluation of the individual's qualifications is needed, with a maximum interval of thirty-nine (39) months;

I. Evaluate an individual's possession of the knowledge and skills under paragraph (12)(D)4. at intervals not to exceed thirty-nine (39) months;

J. Ensure that covered tasks are—

(I) Performed by qualified individuals; or

(II) Directed and observed by qualified individuals; and

K. Submit each program change to designated commission personnel as required by subsection (1)(J).

4. Personnel to whom this subsection applies must possess the knowledge and skills necessary to—

A. Follow the requirements of this rule that relate to the covered tasks they perform;

B. Carry out the procedures in the procedural manual for operations, maintenance, and emergencies established under subsection (12)(C) [*(192.605)*] that relate to the covered tasks they perform;

C. Utilize instruments and equipment that relate to the covered task they perform in accordance with manufacturer's instructions;

D. Know the characteristics and hazards of the gas transported, including flammability range, odorant characteristics, and corrosive properties;

E. Recognize potential ignition sources;

F. Recognize conditions that are likely to cause emergencies, including equipment or facility malfunctions or failure and gas leaks, predict potential consequences of these conditions, and take appropriate corrective action;

G. Take steps necessary to control any accidental release of gas and to minimize the potential for fire or explosion; and

H. Know the proper use of firefighting procedures and equipment, fire suits, and breathing apparatus by utilizing, where feasible, a simulated pipeline emergency condition.

5. Each operator shall continue to meet the training and annual review requirements regarding the operator's emergency procedures in subparagraph (12)(J)2.B., in addition to the qualification program required in paragraph (12)(D)3.

6. Each operator shall provide instruction to the supervisors or designated persons who will determine when an evaluation is necessary under subparagraph (12)(D)3.F.

7. Each operator shall select appropriately knowledgeable individuals to provide training and to perform evaluations. Where hands-on examinations and observations are used, the evaluator should possess the required knowledge to ascertain an individual's ability to perform covered tasks and react to abnormal operating conditions that might occur while performing those tasks.

8. Record keeping. (192.807) Each operator shall maintain records that demonstrate compliance with this subsection.

A. Qualification records shall include:

(I) Identification of the qualified individual(s);

(II) Identification of the covered tasks the individual is qualified to perform;

(III) Date(s) of current qualification; and

(IV) Qualification method(s).

B. 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 (5) years.

9. General. (192.809)

A. Operators must have a written qualification program by April 27, 2001. The program must be available for review by designated commission personnel.

B. Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

C. After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

(E) Verification of Pipeline Material Properties and Attributes: Steel Transmission Pipelines. (192.607)

1. Applicability. Wherever required by this rule, operators of steel transmission pipelines must document and verify material properties and attributes in accordance with this subsection.

2. Documentation of material properties and attributes. Records established under this subsection documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this subsection needed to meet the requirements of the ECA method at subparagraph (12)(U)3.C. [*(192.624(c)(3))*] or the fracture mechanics requirements at subsection (13)(EE) [*(192.712)*] must be maintained for the life of the pipeline.

3. Verification of material properties and attributes. If an operator does not have traceable, verifiable, and complete records required by paragraph (12)(E)2., the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities: Anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

A. For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined at a minimum of five (5) places in at least two (2) circumferential quadrants of the pipe for a minimum total of ten (10) test readings at each pipe cylinder location;

B. For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L;

C. Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes;

D. If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness; and

E. Verification of material properties and attributes for non-line pipe components must comply with paragraph (12)(E)6.

4. Special requirements for nondestructive methods. Procedures developed in accordance with paragraph (12)(E)3. for verification of material properties and attributes using nondestructive methods must—

A. Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage;

B. Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

C. Use test equipment that has been properly calibrated for comparable test materials prior to usage.

5. Sampling multiple segments of pipe. To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:

A. The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds two (2) years, those segments cannot be considered as the same vintage for the purpose of defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous;

B. For each population defined according to subparagraph (12)(E)5.A., the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, in situ evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavation activities pursuant to subsection (12)(I) [*(192.614)*], until completion of the lesser of the following:

(I) One (1) excavation per mile rounded up to the nearest whole number; or

(II) One-hundred-fifty (150) excavations if the population is more than one-hundred-fifty (150) miles;

C. Prior tests conducted for a single excavation according to the requirements of paragraph (12)(E)3. may be counted as one (1) sample under the sampling requirements of this paragraph (12)(E)5.;

D. If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assumed properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a ninety-five percent (95%) confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with subsection (1)(M) [*(192.18)*]; and

E. An operator may use an alternative statistical sampling approach that differs from the requirements specified in subparagraph (12)(E)5.B. The alternative sampling program must use valid statistical bases designed to achieve at least a ninety-five percent (95%) confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with subsection (1)(M) [*(192.18)*].

6. Components. For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (12)(E)3. for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))).

A. Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.

B. Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are—

(I) Larger than two (2) inches in nominal outside diameter;

(II) Material grades of forty-two thousand (42,000) psi (Grade X–42) or greater; or

(III) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

C. Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

7. Uprating. The material properties determined from the destructive or nondestructive tests required by this subsection (12)(E) cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assumed yield strength of twenty-four thousand (24,000) psi in accordance with subparagraph (3)(D)2.B. [*(192.107(b)(2))*].

(G) Change in Class Location—Confirmation or Revision of Maximum Allowable Operating Pressure. (192.611) 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 (1) of the following three (3) paragraphs:

1. If the segment involved has been previously tested in place for a period of not less than eight (8) 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 seventy-two percent (72%) of SMYS of the pipe in Class 1 and 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of SMYS in Class 4 locations;

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 rule for new segments of pipelines in the existing class location; or

3. The segment of pipeline involved must be tested in accordance with the applicable requirements of section (10), and its maximum allowable operating pressure must then be established according to the following criteria:

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; and

B. The corresponding hoop stress may not exceed seventy-two percent (72%) of the SMYS of the pipe in Class 1 and 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of the SMYS in Class 4 locations.

4. The maximum allowable operating pressure confirmed or revised in accordance with this subsection may not exceed the maximum allowable operating pressure established before the confirmation or revision.

5. Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this subsection does not preclude the application of subsections (11)(B) and (C). [*(192.553 and 192.555)*]

6. Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under subsection (12)(F) must be completed within twenty-four (24) months of the change in class location. Pressure reduction under paragraph (12)(G)1. or 2. within the twenty-four- (24-) month period does not preclude establishing a maximum allowable operating pressure under paragraph (12)(G)3., at a later date.

(H) Continuing Surveillance. (192.613)

1. 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.

2. 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 paragraphs (12)(M)1. and 2. [*(192.619[a] and [b])*]

3. Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

A. An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this subparagraph.

B. An operator must commence the inspection required by paragraph (12)(H)3. within seventy-two (72) hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by subparagraph (12)(H)3.A. are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

C. An operator must take prompt and appropriate remedial action to ensure the safe operation of a pipeline based on the information obtained as a result of performing the inspection required by paragraph (12)(H)3. Such actions might include, but are not limited to—

(I) Reducing the operating pressure or shutting down the pipeline;

(II) Modifying, repairing, or replacing any damaged pipeline facilities;

(III) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(IV) Performing additional patrols, surveys, tests, or inspections;

(V) Implementing emergency response activities with federal, state, or local personnel; or

(VI) Notifying affected communities of the steps that can be taken to ensure public safety.

(I) Damage Prevention Program. (192.614)

1. Except for pipelines listed in paragraphs (12)(I)6. and 7., each operator of a buried pipeline shall carry out in accordance with this subsection a written program to prevent damage to that pipeline by excavation activities. For the purpose of this subsection, excavation activities include excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations. Particular attention should be given to excavation activities in close proximity to cast iron mains with remedial actions taken as required by subsection (13)(Z) of this rule. [*(192.755).*]

2. An operator may perform any of the duties specified in paragraph (12)(I)3. 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 subsection. However, an operator must perform the duties of subparagraph (12)(I)3.D. through participation in the

qualified one-call system for Missouri. An operator's pipeline system must be covered by the qualified one-call system for Missouri.

3. The damage prevention program required by paragraph (12)(I)1. must, at a minimum—

A. Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located. A listing of persons involved in excavation activities shall be maintained and updated at least once each calendar year with intervals not exceeding fifteen (15) months. If an operator chooses to participate in an excavator education program of a one-call notification center, as provided for in subparagraphs (12)(I)3.B. and C., then such updated listing shall be provided to the one-call notification center within the one-call notification center participation renewal period. This list should at least include, but not be limited to, the following:

(I) Excavators, contractors, construction companies, engineering firms, etc.—Identification of these should at least include a search of the phone book yellow pages, checking with the area and/or state office of the Associated General Contractors, and checking with the operating engineers local union hall(s);

(II) Telephone company;

(III) Electric utilities and co-ops;

(IV) Water and sewer utilities;

(V) City governments;

(VI) County governments;

(VII) Special road districts;

(VIII) Special water and sewer districts; and

(IX) Highway department district(s);

B. Provide for at least a semiannual general notification of the public in the vicinity of the pipeline. Provide for actual notification of the persons identified in subparagraph (12)(I)3.A., at least once each calendar year at intervals not exceeding fifteen (15) months by **first class,** registered**,** or certified mail**, electronic mail**, or notification through participation in an excavator education program of a one-call notification center meeting the requirements of subparagraph (12)(I)3.C. [*Mailings*]**Notifications** to excavators shall include a copy of the applicable sections of Chapter 319, RSMo, or a summary of the provisions of Chapter 319, RSMo, approved by designated commission personnel, concerning underground facility safety and damage prevention pertaining to excavators. The operator's public notifications and excavator notifications shall include information concerning the existence and purpose of the operator's damage prevention program, as well as information on how to learn the location of underground pipelines before excavation activities are begun;

C. In order to provide for an operator's compliance with the excavator notification requirements of subparagraph (12)(I)3.B., a one-call system's excavator education program must—

(I) Maintain and update a comprehensive listing of excavators who use the one-call notification center and who are identified by the operators pursuant to the requirements of subparagraph (12)(I)3.A.;

(II) Provide for at least semiannual educational [*mailings*]**notifications** to **each of** the excavators named on the comprehensive listing maintained pursuant to part (12)(I)3.C.(I)[*, by first class mail*]**. Notifications must be made by first class mail or electronic mail**; and

(III) Provide for inclusion of the following in at least one (1) of the semiannual [*mailings*]**notifications** specified in part (12)(I)3.C.(II): Chapter 319, RSMo, or a summary of the provisions of Chapter 319, RSMo, approved by designated commission personnel, concerning underground facility safety and damage prevention which pertain to excavators; an explanation of the types of temporary markings normally used to identify the approximate location of underground facilities; and a description of the availability and proper use of the one-call system's notification center;

D. Provide a means of receiving and recording notification of planned excavation activities;

E. Include maintenance of records for subparagraphs (12)(I)3.B.–D. as follows:

(I) Copies of the two (2) most recent annual notifications sent to excavators identified in subparagraph (12)(I)3.A., or the four (4) most recent semiannual notifications sent in accordance with subparagraph (12)(I)3.C., must be retained;

(II) Copies of notifications required in subparagraph (12)(I)3.D. shall be retained for at least two (2) years. At a minimum, these records should include the date and the time the request was received, the actions taken pursuant to the request, and the date the response actions were taken; and

(III) Copies of notification records required by Chapter 319, RSMo, to be maintained by the notification center shall be available to the operator for at least five (5) years;

F. 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;

G. Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins; and

H. Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(I) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(II) In the case of blasting, any inspection must include leakage surveys.

4. Each notification identified in subparagraph (12)(I)3.D. should be evaluated to determine the need for and the extent of inspections. The following factors should be considered in determining the need for and extent of those inspections:

A. The type and duration of the excavation activity involved;

B. The proximity to the operator's facilities;

C. The type of excavating equipment involved;

D. The importance of the operator's facilities;

E. The type of area in which the excavation activity is being performed;

F. The potential for serious incident should damage occur;

G. The prior history of the excavator with the operator; and

H. The potential for damage occurring which may not be easily recognized by the excavator.

5. The operator should pay particular attention, during and after excavation activities, to the possibility of joint leaks and breaks due to settlement when excavation activities occur near cast iron and threaded-coupled steel.

6. A damage prevention program under this subsection is not required for the following pipelines:

A. Pipelines to which access is physically controlled by the operator; and

B. Pipelines that are part of a petroleum gas system subject to subsection (1)(F) of this rule [*(192.11)*] or part of a distribution system operated by a person in connection with that person's leasing of real property or by a condominium or cooperative association.

7. 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:

A. The requirement of paragraph (12)(I)1. that the damage prevention program be written; and

B. The requirements of subparagraphs (12)(I)3.A., (12)(I)3.B., and (12)(I)3.C.

(J) Emergency Plans. (192.615)

1. 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:

A. Receiving, identifying, and classifying notices of events which require immediate response by the operator;

B. Establishing and maintaining adequate means of communication with the appropriate public safety answering point (i.e., 9–1–1 emergency call center), where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9–1–1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. An operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both local and out-of-area calls of each federal, state, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies;

C. Responding promptly and effectively to a notice of each type of emergency, including the following:

(I) Gas detected inside or near a building;

(II) Fire located near or directly involving a pipeline facility;

(III) Explosion occurring near or directly involving a pipeline facility; and

(IV) Natural disaster;

D. Making available personnel, equipment, tools, and materials, as needed at the scene of an emergency;

E. Taking actions directed toward protecting people first and then property;

F. Taking necessary actions, including but not limited to emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released gas to life, property, or the environment;

G. Making safe any actual or potential hazard to life or property;

H. Notifying the appropriate public safety answering point (i.e., 9–1–1 emergency call center) where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in subsection (1)(B), to coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of subsections (4)(U), (12)(X), or (12)(Z);

I. Safely restoring any service outage;

J. Beginning action under subsection (12)(L) [*(192.617)*], if applicable, as soon after the end of the emergency as possible;

K. Actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and requirements set forth in subsections (12)(T), (12)(X), and (12)(Z); and

L. Each operator must develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in subsection (1)(B), is an actual rupture event or a non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture and identify an actual rupture. For operators installing valves in accordance with paragraph (4)(U)4., paragraph (4)(U)5., or that are subject to the requirements in subsection (12)(X), those procedures must provide for rupture identification as soon as practicable.

2. Each operator shall—

A. Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (12)(J)1. as necessary for compliance with those procedures;

B. Train the appropriate operating personnel and conduct an annual review to assure that they are knowledgeable of the emergency procedures and verify that the training is effective; and

C. Review employee activities to determine whether the procedures were effectively followed in each emergency.

3. Each operator must establish and maintain liaison with the appropriate public safety answering point (i.e., 9–1–1 emergency call center) where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, as well as fire, police, and other public officials to—

A. Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

B. Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

C. Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

D. Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

(K) Public Awareness. (192.616)

1. Except for an operator of a master meter system covered under paragraph (12)(K)10., each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the *American Petroleum Institute's (API) Recommended Practice (RP) 1162* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). In addition, the program must provide for notification of the intended groups [*on*]**according to** the following schedule:

A. Appropriate government organizations and persons engaged in excavation related activities must be notified at least annually;

B. The public must be notified at least semiannually; [*and*]

C. Customers must be notified at least semiannually by mailings or hand-delivered messages [*and at least nine (9) times a calendar year by billing messages.*]**;**

D. Customers must be notified at least nine (9) times each calendar year by billing messages;

E. A combination of notifications may be used to meet the requirements of subparagraph (12)(K)1.A. as long as educational content that addresses each of the topics listed in paragraph (12)(K)4. is provided at least annually;

F. A combination of notifications may be used to meet the requirements of subparagraphs (12)(K)1.B. and (12)(K)1.C. as long as educational content that addresses each of the topics listed in paragraph (12)(K)4. is provided at least semiannually; and

G. Each billing message notification required by subparagraph (12)(K)1.D. must at a minimum include educational content that addresses subparagraphs (12)(K)4.A. and (12)(K)4.E.

2. 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.

3. 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.

4. The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

A. Use of a one-call notification system prior to excavation and other damage prevention activities;

B. Possible hazards associated with unintended releases from a gas pipeline facility;

C. Physical indications that such a release may have occurred;

D. Steps that should be taken for public safety in the event of a gas pipeline release; and

E. Procedures for reporting such an event.

5. The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

6. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

7. 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.

8. Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter covered under paragraph (12)(K)10. must complete development of its written procedure by June 13, 2008. Operators must submit their completed programs and any program changes to designated commission personnel as required by subsection (1)(J).

9. The operator's program documentation and evaluation results must be available for periodic review by designated commission personnel.

10. Unless the operator transports gas as a primary activity, the operator of a master meter is not required to develop a public awareness program as prescribed in paragraphs (12)(K)1.–7. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter is located on property the

operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

A. A description of the purpose and reliability of the pipeline;

B. An overview of the hazards of the pipeline and prevention measures used;

C. Information about damage prevention;

D. How to recognize and respond to a leak; and

E. How to get additional information.

(L) Investigation of Failures and Incidents. (192.617)

1. Post-failure and incident procedures. Each operator must establish and follow procedures for investigating and analyzing failures and federal incidents as defined in 20 CSR 4240-40.020(2)(D), including sending the failed pipe, component, or equipment for laboratory testing or examination, where appropriate, for the purpose of determining the causes and contributing factor(s) of the failure or incident and minimizing the possibility of a recurrence.

2. Post-failure and incident lessons learned. Each operator **of a transmission or distribution pipeline** must develop, implement, and incorporate lessons learned from a post-failure or incident review into its written procedures, including personnel training and qualification programs[*,*]**;** and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.

3. Analysis of rupture and valve shutoffs. If an incident on a gas transmission pipeline [*or a Type A gathering pipeline*] involves the closure of a rupture-mitigation valve (RMV), as defined in subsection (1)(B), or the closure of alternative equivalent technology, the operator of the pipeline must also conduct a post-incident analysis of all of the factors that may have impacted the release volume and the consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. The requirements of this paragraph are not applicable to **gas** distribution [*pipelines*] or [*Types B and C*] gas gathering pipelines. The analysis must include all relevant factors impacting the release volume and consequences, including**,** but not limited to**,** the following:

A. Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the incident;

B. Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel;

C. Actual response time from identifying a rupture following a notification of potential rupture, as defined in subsection (1)(B), to initiation of mitigative actions and isolation of the pipeline segment, and the appropriateness and effectiveness of the mitigative actions taken;

D. Location and timeliness of actuation of RMVs or alternative equivalent technologies; and

E. All other factors the operator deems appropriate.

4. Rupture post-failure and incident summary. If a failure or incident on a gas transmission pipeline [*or a Type A gathering pipeline*] involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV (as those terms are defined in subsection (1)(B)), or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by paragraph (12)(L)3. within ninety (90) days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-failure or incident summary, and all other reviews and analyses

produced under the requirements of this subsection, must be reviewed, dated, and signed by the operator's appropriate senior executive officer. The final post-failure or incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline. The requirements of this paragraph are not applicable to **gas** distribution [*pipelines*] or [*Types B and C*] gas gathering pipelines.

(M) Maximum Allowable Operating Pressure−Steel or Plastic Pipelines. (192.619 and 192.620)

1. Except as provided in paragraphs (12)(M)3., 4., and 6., no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

A. The design pressure of the weakest element in the segment, determined in accordance with sections (3) and (4). However, for steel pipe in pipelines being converted under subsection (1)(H) or uprated under section (11), if any variable necessary to determine the design pressure under the design formula in subsection (3)(C) is unknown, one (1) of the following pressures is to be used as design pressure:

(I) Eighty percent (80%) of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), reduced by the appropriate factor in part (12)(M)1.B.(II); or

(II) If the pipe is twelve and three-quarter inches (12 (3/4") (three hundred twenty-four (324) mm) or less in outside diameter and is not tested to yield under this paragraph, two hundred (200) psi (one thousand three hundred seventy-nine (1379) kPa) gauge;

B. The pressure obtained by dividing the highest pressure to which the segment was tested after construction or uprated as follows:

(I) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5; and

(II) For steel pipe operated at one hundred (100) psi (six hundred eighty-nine (689) kPa) gauge or more, the test pressure is divided by a factor determined in accordance with the following table:

Class Location	Factors[1,2], Segment			
	Installed before Nov. 12, 1970	Installed after Nov. 11, 1970, and before July 1, 2020	Installed on or after July 1, 2020	Converted under subsection (1)(H) (192.14)
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1]For segments installed, uprated, or converted after July 31, 1977, that are located on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

[2]For a component with a design pressure established in accordance with paragraphs (4)(H)1. or (4)(H)2. of this rule [*(192.153(a) or (b))*] installed after July 14, 2004, the factor is 1.3;

C. The highest actual operating pressure to which the segment was subjected during the five (5) years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested in accordance with subparagraph (12)(M)1.B. after the applicable date in the third column or the segment was uprated in accordance with section (11); and

Pipeline Segment	Pressure Date	Test Date

Onshore regulated gathering pipeline (Type A or Type B under 49 CFR 192(b)) that first became subject to this rule after April 13, 2006 (see subsection (1)(E)).	March 15, 2006, or date line becomes subject to this rule, whichever is later.	Five (5) years preceding applicable date in second column.
Onshore regulated gathering pipeline (Type C under 49 CFR 192.9(d)) that first became subject to this rule on or after May 16, 2022.	May 16, 2023, or date pipeline becomes subject to this rule, whichever is later.	Five (5) years preceding applicable date in second column.
Onshore transmission pipeline that was a gathering line not subject to this rule before March 15, 2006 (see subsection (1)(E)).	March 15, 2006, or date line becomes subject to this rule, whichever is later.	Five (5) years preceding applicable date in second column.
All other pipelines.	July 1, 1970	July 1, 1965

D. The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with subsection (12)(E), if applicable, and the history of the pipeline segment, including known corrosion and the actual operating pressure.

2. No person may operate a segment of pipeline to which this subsection applies unless overpressure protective devices are installed for the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with subsection (4)(CC) of this rule. [*(192.195)*]

3. The requirements on pressure restrictions in this subsection do not apply in the following instances:

A. 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 five (5) years preceding the applicable date in the second column of the table in subparagraph (12)(M)1.C. An operator must still comply with subsection (12)(G); and

B. For any Type C gas gathering pipeline under [*subsection*]**paragraph** (1)(E)**2.** [*of this rule (192.9)*] existing on or before May 16, 2022, that was not previously subject to this rule and the operator cannot determine the actual operating pressure of the pipeline for the five (5) years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA. The operator must notify PHMSA in accordance with subsection (1)(M) of this rule. The notification must include the following information:

(I) The proposed MAOP of the pipeline;

(II) Description of pipeline segment for which alternate methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age;

(III) Pipeline operating data, including operating history and maintenance history;

(IV) Description of methods being used to establish MAOP;

(V) Technical justification for use of the methods chosen to establish MAOP; and

(VI) Evidence of review and acceptance of the justification by a qualified technical subject matter expert.

4. No person may operate a pipeline at a pressure that results in a hoop stress greater than seventy-two percent (72%) of SMYS.

5. Notwithstanding the requirements in paragraphs (12)(M)1. through 4., operators of steel transmission pipelines that meet the criteria specified in paragraph (12)(U)1. must establish and document the maximum allowable operating pressure in accordance with subsection (12)(U).

6. Operators of steel transmission pipelines must make and retain records necessary to establish and document the MAOP of each pipeline segment in accordance with paragraphs (12)(M)1. through 5. as follows:

A. Operators of pipelines in operation as of July 1, 2020, must retain any existing records establishing MAOP for the life of the pipeline;

B. Operators of pipelines in operation as of July 1, 2020, that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with subsection (12)(U), must retain the records reconfirming MAOP for the life of the pipeline; and

C. Operators of pipelines placed in operation after July 1, 2020, must make and retain records establishing MAOP for the life of the pipeline.

7. Alternative maximum allowable operating pressure for certain steel pipelines. (192.620) The federal regulations at 49 CFR 192.620 are not adopted in this rule.

(N) Maximum Allowable Operating Pressure—High-Pressure Distribution Systems. (192.621)

1. 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:

A. The design pressure of the weakest element in the segment, determined in accordance with sections (3) and (4);

B. Sixty (60) psi (414 kPa) gauge, for a segment of a distribution system otherwise designated to operate at over sixty (60) psi (414 kPa) gauge, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of subsection (4)(DD) [*(192.197[c])*];

C. Twenty-five (25) psi (172 kPa) gauge in segments of cast iron pipe in which there are unreinforced bell and spigot joints;

D. The pressure limits to which a joint could be subjected without the possibility of its parting; and

E. 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.

2. No person may operate a segment of pipeline to which this subsection applies, unless overpressure protective devices are installed for the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with subsection (4)(CC). [*(192.195)*]

(U) Maximum Allowable Operating Pressure Reconfirmation: Steel Transmission Pipelines. (192.624)

1. Applicability. Operators of steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:

A. Records necessary to establish the MAOP in accordance with subparagraph (12)(M)1.B., including records required by paragraph (10)(I)1., are not traceable, verifiable, and complete and the pipeline is located in one (1) of the following locations:

(I) A high consequence area as defined in 49 CFR 192.903 (incorporated by reference in section (16)); or

(II) A Class 3 or Class 4 location.

B. The pipeline segment's MAOP was established in accordance with paragraph (12)(M)3., the pipeline segment's MAOP is greater than or equal to thirty percent (30%) of the specified minimum yield strength, and the pipeline segment is located in one (1) of the following areas:

(I) A high consequence area as defined in 49 CFR 192.903 (incorporated by reference in section (16));

(II) A Class 3 or Class 4 location; or

(III) A "moderate consequence area" as defined in subsection (1)(B), if the pipeline segment can accommodate inspection by means of instrumented inline inspection tools.

2. Procedures and completion dates. Operators of a pipeline subject to this subsection must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet a condition of paragraph (12)(U)1., and for performing a spike test or material verification in accordance with subsections (10)(K) and (12)(E), if applicable. All actions required by this subsection must be completed according to the following schedule:

A. Operators must complete all actions required by this subsection on at least fifty percent (50%) of the pipeline mileage by July 3, 2028;

B. Operators must complete all actions required by this subsection on one-hundred percent (100%) of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed four (4) years after the pipeline segment first meets a condition of paragraph (12)(U)1. (e.g., due to a location becoming a high consequence area), whichever is later; and

C. If operational and environmental constraints limit an operator from meeting the deadlines in this subsection, the operator may petition for an extension of the completion deadlines by up to one (1) year, upon submittal of a notification in accordance with subsection (1)(M) [*(192.18)*]. The notification must include an up-to-date plan for completing all actions in accordance with this subsection, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety.

3. Maximum allowable operating pressure determination. Operators of a pipeline segment meeting a condition in paragraph (12)(U)1. must reconfirm its MAOP using one of the following methods:

A. Method 1: Pressure test. Perform a pressure test and verify material properties records in accordance with subsection (12)(E) and the following requirements:

(I) Pressure test. Perform a pressure test in accordance with section (10). The MAOP must be equal to the test pressure divided by the greater of either 1.25 or the applicable class location factor in (12)(M)1.B.(II);

(II) Material properties records. Determine if the following material properties records are documented in traceable, verifiable, and complete records: diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength); and

(III) Material properties verification. If any of the records required by (12)(U)3.A.(II) are not documented in traceable, verifiable, and complete records, the operator must obtain the missing records in accordance with subsection (12)(E). An operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during the pressure test, the operator must test any removed pipe from the pressure test failure in accordance with subsection (12)(E);

B. Method 2: Pressure Reduction. Reduce pressure, as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the five (5) years preceding October 1, 2019, divided by the greater of 1.25 or the applicable class location factor in (12)(M)1.B.(II). The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight (8) hours during a continuous thirty- (30-) day period. The value used as the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (i.e., the location-specific operating pressure at each location).

(I) Where the pipeline segment has had a class location change in accordance with subsection (12)(G), and records documenting diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

(a) For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the five (5) years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4; and

(b) For pipeline segments where a class location changed from Class 1 to Class 3, reduce the pipeline MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the five (5) years preceding October 1, 2019, divided by 2.00.

(II) Future uprating of the pipeline segment in accordance with section (11) is allowed if the MAOP is established using Method 2.

(III) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with subsection (1)(M) [*(192.18)*] no later than seven (7) calendar days after establishing the reduced MAOP. The notification must include the following details:

(a) Descriptions of the operational constraints, special circumstances, or other factors that preclude, or make it impractical, to use the pressure reduction factor specified in subparagraph (12)(U)3.B.;

(b) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with subsection (13)(EE);

(c) Justification that establishing MAOP by another method allowed by this subsection is impractical;

(d) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material properties records, material properties verified in accordance with subsection (12)(E), and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

(e) Planned duration for operating at the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressures and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts;

C. Method 3: Engineering Critical Assessment (ECA). Conduct an ECA in accordance with subsection (12)(V);

D. Method 4: Pipe Replacement. Replace the pipeline segment in accordance with this rule;

E. Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius. Pipelines with a potential impact radius (PIR) less than or equal to one-hundred-fifty (150) feet may establish the MAOP as follows:

(I) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during five (5) years preceding October 1, 2019, divided by 1.1. The highest actual sustained pressure must have been reached for a minimum cumulative duration of eight (8) hours during one continuous thirty- (30-) day period. The reduced MAOP must account for differences between discharge and upstream pressure on the pipeline by use of either the lowest value for the entire pipeline segment or the operating pressure gradient (i.e., the location specific operating pressure at each location);

(II) Conduct patrols in accordance with paragraphs (13)(C)1. and 3. and conduct instrumented leakage surveys in accordance with subsection (13)(D) at intervals not to exceed those in the following table 1:

Table 1

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3½ months, but at least four times each calendar year	3½ months, but at least four times each calendar year
(B) Class 3 and Class 4	3 months, but at least six times each calendar year	3 months, but at least six times each calendar year

(III) Under Method 5, future uprating of the pipeline segment in accordance with section (11) is allowed; or

F. Method 6: Alternative Technology. Operators may use an alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with subsection (1)(M) [*(192.18)*]. The notification must include descriptions of the following details:

(I) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated;

(II) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

(III) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

(IV) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

(V) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with subsection (13)(EE);

(VI) Operational monitoring procedures;

(VII) Methodology and criteria used to justify and establish the MAOP; and

(VIII) Documentation of the operator's processes and procedures used to implement the use of the alternative technology, including any records generated through its use.

4. Records. An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this subsection for the life of the pipeline.

(V) Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Steel Transmission Pipelines. (192.632) When an operator conducts an MAOP reconfirmation in accordance with subparagraph (12)(U)3.C. "Method 3" using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: threats; loadings, and operational circumstances relevant to those threats, including along the pipeline right-of way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

1. ECA Analysis.

A. The material properties required to perform an ECA analysis in accordance with paragraph (12)(V)1. are as follows: Diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with paragraph (12)(V)1. are not documented in traceable, verifiable, and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with subsection (12)(E). The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with subsection (12)(V), along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by section (9), cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by subsections (12)(L) and (13)(DD) and section (16).

B. The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:

(I) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with subsection (13)(EE);

(II) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes, or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)) or R–STRENG (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over eighty percent (80%) of the wall thickness and are subject to the limitations prescribed in the equations' procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth);

(III) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented; and

(IV) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume thirty thousand (30,000) psi or determine the material properties using subsection (12)(E).

C. The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

D. The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in part (12)(M)1.B.(II).

2. Assessment to determine defects remaining in the pipe. An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (12)(V)1.

A. An operator may use a previous pressure test that complied with section (10) to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of section (10) exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in accordance with subsection (13)(EE). The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a reassessment interval in accordance with the methodology in subsection (13)(EE).

B. Operators may use an inline inspection program in accordance with paragraph (12)(V)3.

C. Operators may use "other technology" if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use "other technology" in the ECA, it must notify PHMSA in advance of using the "other technology" in accordance with subsection (1)(M) [*(192.18)*]. The "other technology" notification must have—

(I) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and

(II) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.

3. In-line inspection. An inline inspection (ILI) program to determine the defects remaining in the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.

A. If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.

B. If the pipeline has had a reportable federal incident, as defined in 20 CSR 4240-40.020(2)(D), attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

C. Inline inspection must be performed in accordance with subsection (9)(X).

D. An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.

E. Interpretation and evaluation of assessment results must meet the requirements of subsections (13)(H) and (13)(DD) and section (16), and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation, and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

F. Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in subsection (13)(H) and 49 CFR 192.933 (incorporated by reference in section (16)).

4. Defect remaining life. If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with subsection (13)(EE).

5. Records. An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this subsection for the life of the pipeline.

(W) Change in Class Location—Change in Valve Spacing. **(192.610)**

1. If a class location change on a transmission pipeline occurs after October 5, 2022, and results in pipe replacement, of two (2) or more miles, in the aggregate, within any five (5) contiguous miles within a twenty-four- (24-) month period, to meet the maximum allowable operating pressure (MAOP) requirements in subsections (12)(G) or (12)(M), then the requirements in subsections (4)(U), (12)(X), and (12)(Z), as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those subsections. Such valves must be installed within twenty-four (24) months of the class location change in accordance with the timing requirement in paragraph (12)(G)6. for compliance after a class location change.

2. If a class location change on a gas transmission pipeline occurs after October 5, 2022, and results in pipe replacement of less than two (2) miles within five (5) contiguous miles during a twenty-four- (24-) month period, to meet the MAOP requirements in subsection (12)(G) or (12)(M), then within twenty-four (24) months of the class location change, in accordance with paragraph (12)(G)6., the operator must either—

A. Comply with the valve spacing requirements of paragraph (4)(U)1. for the replaced pipeline segment; or

B. Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two (2) RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment must not exceed twenty (20) miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of subsection (12)(Z).

3. The provisions of paragraph (12)(W)2. do not apply to pipeline replacements that amount to less than one thousand feet (1,000') within any one (1) contiguous mile during any twenty-four- (24-) month period.

(X) Transmission Lines—Valve Shut-Off for Rupture Mitigation. **(192.634)**

1. Applicability. For new or entirely replaced transmission pipeline segments with diameters of six inches (6") or greater that are located in high-consequence areas (HCA) or Class 3 or Class 4 locations and that are installed after April 10, 2023, an operator must install or use existing rupture mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this subsection and subsections (4)(U) and (12)(Z). RMVs and alternative equivalent technologies must be operational within fourteen (14) days of placing the new or replaced pipeline segment into service. An operator may request an extension of this fourteen- (14-) day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in subsection (1)(M), that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this subsection apply to all applicable pipe replacement projects, even those that do not otherwise involve the addition or replacement of a valve. This subsection does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR), as defined in 49 CFR 192.903 (incorporated by reference in section (16)), that is less than or equal to one hundred fifty feet (150').

2. Maximum spacing between valves. RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements:

A. Shut-off segment. For purposes of this subsection, a "shut-off segment" means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two (2) RMVs or alternative equivalent technologies. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in subsection (1)(B), or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within thirty (30) minutes following rupture identification, as that term is defined in subsection (1)(B). Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with subsection (1)(M);

B. Shut-off segment valve spacing. A pipeline subject to paragraph (12)(X)1. must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed—

(I) Eight (8) miles for any Class 4 location;

(II) Fifteen (15) miles for any Class 3 location; or

(III) Twenty (20) miles for all other locations;

C. Laterals. Laterals extending from shut-off segments that contribute less than five percent (5%) of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of the laterals contributing gas volumes to the shut-off segment do not contribute more than five percent (5%) of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are twelve inches (12") in diameter or less, a check valve that allows gas to flow freely in one (1) direction and contains a mechanism to automatically prevent flow in the other direction may be used as an alternative equivalent technology where it is positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this paragraph are not subject to subsection (12)(Z), but they must be inspected, operated, and remediated in accordance with subsection (13)(U), including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify PHMSA in accordance with subsections (1)(M) and (4)(U), and develop and implement maintenance procedures for such equipment that meet subsection (13)(U); and

D. Crossovers. An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify PHMSA in accordance with subsections (1)(M) and (4)(U).

(Y) Notification of Potential Rupture. (192.635)

1. As used in this rule, a "notification of potential rupture" refers to the notification of, or observation by, an operator (e.g., by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one (1) or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline:

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

B. An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting subparagraph (12)(Y)1.A.; or

C. Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline.

2. A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph (12)(Y)1.

3. This subsection does not apply to any gas gathering line.

(13) Maintenance.

(G) Transmission Lines—General Requirements for Repair Procedures. (192.711)

1. Temporary repairs. Each operator must take immediate temporary measures to protect the public whenever—

A. A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above forty percent (40%) of the SMYS; and

B. It is not feasible to make a permanent repair at the time of discovery.

2. Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following:

A. Non-integrity management repairs for gathering lines. For gathering lines subject to this subsection in accordance with [*subsection*]**paragraph** (1)(E)**2.**, an operator must make permanent repairs as soon as feasible;

B. Non-integrity management repairs for transmission lines. Except for gathering lines exempted from this subsection in accordance with [*subsection*]**paragraph** (1)(E)**2.**, after May 24, 2023, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under section (16)—Pipeline Integrity Management for Transmission Lines (Subpart O), it must correct the condition as prescribed in subsection (13)(GG); and

C. Integrity management repairs. When an operator discovers a condition on a pipeline covered under section (16)—Pipeline Integrity Management for Transmission Lines (Subpart O), the operator must remediate the condition as prescribed by 49 CFR 192.933(d) (this federal regulation is incorporated by reference and adopted in section (16)).

3. Welded patch. Except as provided in subparagraph (13)(J)2.C. [*(192.717[b][3])*], no operator may use a welded patch as a means of repair.

(I) Transmission Lines—Permanent Field Repair of Welds. (192.715) Each weld that is unacceptable under paragraph (5)(I)3. [*(192.241[c])*] must be repaired as follows:

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 subsection (5)(K) [*(192.245)*];

2. A weld may be repaired in accordance with subsection (5)(K) [*(192.245)*] while the segment of transmission line is in service if—

A. The weld is not leaking;

B. The pressure in the segment is reduced so that it does not produce a stress that is more than twenty percent (20%) of the SMYS of the pipe; and

C. Grinding of the defective area can be limited so that at least one-eighth inch (1/8") (3.2 millimeters) thickness in the pipe weld remains; and

3. A defective weld which cannot be repaired in accordance with paragraph (13)(I)1. or 2. must be repaired by installing a full encirclement welded split sleeve of appropriate design.

(K) Transmission Lines—Testing of Repairs. (192.719)

1. 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.

2. Testing of repairs made by welding. Each repair made by welding in accordance with subsections (13)(H), (I), and (J) [*(192.713, 192.715, and 192.717)*] must be examined in accordance with subsection (5)(I). [*(192.241)*]

(L) Distribution Systems—Patrolling. (192.721)

1. 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.

2. Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

A. In business districts, at intervals not exceeding four and one-half (4 1/2) months**,** but at least four (4) times each calendar year; and

B. Outside business districts, at intervals not exceeding seven and one-half (7 1/2) months, but at least twice each calendar year.

3. Feeder lines shall be patrolled at intervals not exceeding fifteen (15) months but at least once each calendar year.

(N) Test Requirements for Reinstating Service Lines and Fuel Lines. (192.725)

1. Except as provided in paragraphs (13)(N)2. and 4., each disconnected service line must be tested in the same manner as a new service line and the associated fuel line must meet the requirements of subsection (12)(S) before being reinstated.

2. Before reconnecting, each service line temporarily disconnected from the transmission line or main for any reason must be tested from the point of disconnection to the service line valve in the same manner as a new service line. 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. If continuous service is not maintained, the requirements in subsection (12)(S) must be met for the associated fuel line.

3. Except for system outages, each fuel line to which service has been discontinued shall have service resumed in accordance with subsection (12)(S). Each fuel line restored after a system outage shall have service resumed in accordance with subparagraph (12)(S)1.A. and the procedures required under subparagraph (12)(J)1.I. [*(192.615[a][9])*]

4. Each service line temporarily disconnected from the transmission line or main due to third party damage must be tested from the point of disconnection to the main in the same manner as a new service line, or it may be surveyed from the point of disconnection to the main using a leak detection instrument.

(O) Abandonment or Deactivation of Facilities. (192.727)

1. Each operator shall perform abandonment or deactivation of pipelines in accordance with the requirements of this subsection.

2. Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas, 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.

3. Except for service lines, each inactive pipeline that is not being maintained under this rule must be disconnected from all sources and supplies of gas, purged of gas, 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.

4. Whenever service to a customer is discontinued, one (1) of the following must be complied with:

A. 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;

B. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly; or

C. The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

5. If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging.

6. Each abandoned vault must be filled with a suitable compacted material.

7. For each abandoned 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. The addresses (mail and email) and phone numbers given in this paragraph are from 49 CFR 192.727(g) as published on October 1, 2009. Please consult the current edition of 49 CFR part 192 for any updates to these addresses and phone numbers.

A. 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.phmsa.dot.gov [*or contact the NPMS National Repository at (703) 317-3073*]. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax, or email to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE, Washington, DC 20590-0001; fax (202) 366-4566; email[,] [*InformationResourcesManager@phmsa.dot.gov*]**InformationResourcesManager@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.

B. *(Reserved)*

(P) Compressor Stations—Inspection and Testing of Relief Devices. (192.731)

1. Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with subsections (13)(R) and (T) [*(192.739 and 192.743)*], and must be operated periodically to determine that it opens at the correct set pressure.

2. Any defective or inadequate equipment found must be promptly repaired or replaced.

3. Each remote control shutdown device must be inspected and tested at intervals not exceeding fifteen (15) months but at least once each calendar year to determine that it functions properly.

(Y) Caulked Bell and Spigot Joints. (192.753)

1. Each cast iron caulked bell and spigot joint that is subject to pressures of more than twenty-five (25) psi (172 kPa) gauge must be sealed with—

A. A mechanical leak clamp; or

B. A material or device which—

(I) Does not reduce the flexibility of the joint;

(II) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(III) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of paragraphs (2)(B)1. and 2. and subsection (4)(B). [*(192.53[a] and [b] and 192.143)*]

2. Each cast iron caulked bell and spigot joint that is subject to pressures of twenty-five (25) psi (172 kPa) gauge or less and is exposed for any reason must be sealed by a means other than caulking.

(Z) Protecting or Replacing Disturbed Cast Iron Pipelines. (192.755) When an operator has knowledge that the support for a segment of a buried cast iron pipeline is disturbed or that an excavation or erosion is nearby, the operator shall determine if more than half the pipe diameter lies within the area of affected soil. For the purposes of this subsection, "area of affected soil" refers to the area above a line drawn from the bottom of the excavation or erosion, at the side nearest the main, at a forty-five degree (45°) angle from the horizontal (a lesser angle should be used for sandy or loose soils, or a greater angle may be used for certain consolidated soils if the angle can be substantiated by the operator). If more than half the pipe diameter lies within the area of affected soil, the following measures/precautions must be taken—

1. That segment of the pipeline must be protected, as necessary, against damage during the disturbance by—

A. Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

B. Impact forces by vehicles;

C. Earth movement;

D. Water leaks or sewer failures that could remove or undermine pipe support;

E. Apparent future excavations near the pipeline; or

F. Other foreseeable outside forces which may subject that segment of the pipeline to bending stress;

2. If eight inches (8") or less in nominal diameter, then as soon as feasible, this segment of cast iron pipeline, which shall include a minimum of ten feet (10') beyond the area of affected soil, must be replaced, except as noted in paragraph (13)(Z)4.;

3. If greater than eight inches (8") in nominal diameter, then 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 subsection (7)(J) [*(192.319)*] and paragraph (7)(I)1. [*(192.317[a])*]; and

4. Replacement of cast iron pipelines would not necessarily be required if—

A. The support beneath the pipe is removed for a length less than ten (10) times the nominal pipe diameter not to exceed six feet (6');

B. For parallel excavations, the pipe lies within the area of affected soil for a length less than ten (10) times the nominal pipe diameter not to exceed six feet (6');

C. The excavation is made by the operator in the course of routine maintenance, such as leak repairs to the main or service line installation, where the exposed portion of the main does not exceed six feet (6'), and the backfill supporting the pipe is replaced and compacted by the operator; or

D. Permanent or temporary shoring was adequately installed to protect the cast iron pipeline during excavation and backfilling.

(BB) Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Regulated Gathering or Transmission Pipelines. (192.740)

1. This subsection applies, except as provided in paragraph (13)(BB)3., to any service line directly connected to a transmission pipeline or regulated gathering pipeline as determined in [*subsection*]**paragraph** (1)(E)**1.** [*of this rule (192.8)*] that is not operated as part of a distribution system.

2. Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every three (3) calendar years, not exceeding thirty-nine (39) months, to determine that it is—

A. In good mechanical condition;

B. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

C. Set to control or relieve at the correct pressure consistent with the pressure limits of subsection (4)(DD); and to limit the pressure on the inlet of the service regulator to sixty (60) psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and

D. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

3. This subsection does not apply to equipment installed on—

A. A service line that only serves engines that power irrigation pumps; or

B. A service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in [*subsection*]**paragraph** (1)(E)**1.** [*of this rule (192.8).*]

(GG) Transmission Lines—Repair Criteria for Transmission Pipelines. (192.714)

1. Applicability. This section applies to transmission pipelines not subject to the repair criteria in section (16)—Pipeline Integrity Management for Transmission Lines (Subpart O). Pipeline segments that are located in high consequence areas, as defined in 49 CFR 192.903 (incorporated by reference in section (16)), must comply with the applicable actions specified by the integrity management requirements in section (16)—Pipeline Integrity Management for Transmission Lines (Subpart O).

2. General. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure

pressure determined in accordance with subsection (13)(EE) during repair operations. Repairs performed in accordance with this subsection must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through subsection (12)(E). Until documented material properties are available, the operator must use the conservative assumptions in either subparagraph (13)(EE)5.B. or, if appropriate following a pressure test, in subparagraph (13)(EE)4.C.

3. Schedule for evaluation and remediation. An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph (13)(GG)4. provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME[*/ANSI*] B31.8S (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)), [*section*]**Section** 7, Figure [*4*]**7.2.1–1**. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in paragraph (13)(GG)4. in a steel transmission pipeline must be—

A. Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of subsection (3)(C) and the design factors for the class location in which it is located; or

B. Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure pressure times the design factor for the class location in which it is located.

4. Remediation of certain conditions. For transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:

A. Immediate repair conditions. An operator's evaluation and remediation schedule for immediate repair conditions must follow section 7 of ASME/ANSI B31.8S–**2004** (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)). An operator must repair the following conditions immediately upon discovery:

(I) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with paragraph (13)(EE)2., of less than or equal to 1.1 times the MAOP;

(II) A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with paragraph (13)(EE)3. demonstrates critical strain levels are not exceeded;

(III) Metal loss greater than eighty percent (80%) of nominal wall regardless of dimensions;

(IV) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency [*or high-frequency*] electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with paragraph (13)(EE)4. is less than 1.25 times the MAOP;

(V) A crack or crack-like anomaly meeting any of the following criteria:

(a) Crack depth plus any metal loss is greater than fifty percent (50%) of pipe wall thickness; **or**

(b) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; [*or*

(c) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with (13)(EE)4., that is less than 1.25 times the MAOP;] and

(VI) An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action.

B. Two- (2-) year conditions. An operator must repair the following conditions within two (2) years of discovery:

(I) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than six percent (6%) of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with paragraph (13)(EE)3. demonstrates critical strain levels are not exceeded;

(II) A dent with a depth greater than two percent (2%) of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal or helical (spiral) seam weld, unless an engineering analysis performed in accordance with paragraph (13)(EE)3. demonstrates critical strain levels are not exceeded;

(III) A dent located between the 4 o'clock and 8 o'clock positions (lower 1⁄3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with paragraph (13)(EE)3. demonstrates critical strain levels are not exceeded;

(IV) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with paragraph (13)(EE)2. at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S–**2004** (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)), section 7, Figure 4, as specified in paragraph (13)(GG)3.;

(V) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with paragraph (13)(EE)2., less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with subsection (12)(G), or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations;

(VI) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with paragraph (13)(EE)4. is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with subsection (12)(G), or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations; and

(VII) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with paragraph (13)(EE)4., that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with subsection (12)(G), or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

C. Monitored conditions. An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(I) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom 1⁄3 of the pipe) with a depth greater than six percent (6%) of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis, performed in accordance with paragraph (13)(EE)3., demonstrates critical strain levels are not exceeded;

(II) A dent located between the 8 o'clock and 4 o'clock positions (upper 2⁄3 of the pipe) with a depth greater than six percent (6%) of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with paragraph (13)(EE)3. determines that critical strain levels are not exceeded;

(III) A dent with a depth greater than two percent (2%) of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with paragraph (13)(EE)3., demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties;

(IV) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with paragraph (13)(EE)3. demonstrates critical strain levels are not exceeded;

(V) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with paragraph (13)(EE)4., is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with subsection (12)(G), or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations; and

(VI) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with paragraph (13)(EE)4., is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with subsection (12)(G), or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

5. Temporary pressure reduction.

A. Immediately upon discovery and until an operator remediates the condition specified in subparagraph (13)(GG)4.A., or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in subparagraph (13)(GG)4.B., the operator must reduce the operating pressure of the affected pipeline to any one (1) of the following based on safety considerations for the public and operating personnel:

(I) A level not exceeding eighty percent (80%) of the operating pressure at the time the condition was discovered;

(II) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(III) A level not exceeding the predicted failure pressure divided by 1.1.

B. An operator must notify PHMSA in accordance with subsection (1)(M) if it cannot meet the schedule for evaluation and remediation required under paragraph (13)(GG)3. or paragraph (13)(GG)4. and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this subsection.

C. When a pressure reduction, in accordance with paragraph (13)(GG)5., exceeds three hundred sixty-five (365) days, an operator must notify PHMSA in accordance with subsection (1)(M) and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

D. An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of five (5) years after the pipeline has been repaired.

6. Other conditions. Unless another time frame is specified in paragraph (13)(GG)4., an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.

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

8. Determining predicted failure pressures and critical strain levels. An operator must perform all determinations of predicted failure pressures and critical strain levels required by this subsection in accordance with subsection (13)(EE).

(14) Gas Leaks.

(C) Leak Classifications. The leak classifications in this subsection apply to pipelines, and do not apply to fuel lines. The definitions for "pipeline," "fuel line," "reading," "sustained reading," "building," "tunnel," and "vault or manhole" are included in subsection (1)(B). The definition for "reading" is the highest sustained reading when testing in a bar hole or opening without induced ventilation. Thus, the leak classification examples involving a gas reading do not apply to outside pipelines located aboveground. Even though the leak classifications do not apply to fuel lines, an operator must respond immediately to each notice of an inside leak or odor as required in paragraphs (12)(J)1., (14)(B)1., and (14)(B)2. In addition, the requirements in paragraph (12)(S)3. apply to fuel lines that are determined to be unsafe.

1. Class 1 leak is a gas leak which, due to its location and/or magnitude, constitutes an immediate hazard to a building and/or the general public. A Class 1 leak requires immediate corrective action. Examples of Class 1 leaks are: a gas fire, flash, or explosion; broken gas facilities such as contractor damage, main failures or blowing gas in a populated area; an indication of gas present in a building emanating from operator-owned facilities; a gas reading equal to or above the lower explosive limit in a tunnel, sanitary sewer, or confined area; gas

entering a building or in imminent danger of doing so; and any leak which, in the judgment of the supervisor at the scene, is regarded as immediately hazardous to the public and/or property. When venting at or near the leak is the immediate corrective action taken for Class 1 leaks where gas is detected entering a building, the leak may be reclassified to a Class 2 leak if the gas is no longer entering the building, nor is in imminent danger of doing so. However, the leak shall be rechecked daily and repaired within fifteen (15) days. Leaks of this nature, if not repaired within five (5) days, may need to be reported as a safety-related condition, as required in 20 CSR 4240-40.020(12) and (13). [*(191.23 and 191.25)*]

2. Class 2 leak is a leak that does not constitute an immediate hazard to a building or to the general public, but is of a nature requiring action as soon as possible. The leak of this classification must be rechecked every fifteen (15) days, until repaired, to determine that no immediate hazard exists. A Class 2 leak may be properly reclassified to a lower leak classification within fifteen (15) days after the initial investigation. Class 2 leaks due to readings in sanitary sewers, tunnels, or confined areas must be repaired or properly reclassified within fifteen (15) days after the initial investigation. All other Class 2 leaks must be eliminated within forty-five (45) days after the initial investigation, unless it is definitely included and scheduled in a rehabilitation or replacement program to be completed within a period of one (1) year, in which case the leak must be rechecked every fifteen (15) days to determine that no immediate hazard exists. Examples of Class 2 leaks are: a leak from a transmission line discernible twenty-five feet (25') or more from the line and within one hundred feet (100') of a building; any reading outside a building at the foundation or within five feet (5') of the foundation; any reading greater than fifty percent (50%) gas-in-air located five to fifteen feet (5'–15') from a building; any reading below the lower explosive limit in a tunnel, sanitary sewer, or confined area; any reading equal to or above the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 leak, which in the judgment of the supervisor at the scene, is regarded as requiring Class 2 leak priority.

3. Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine action. These leaks must be repaired within five (5) years and be rechecked twice per calendar year, not to exceed six and one-half (6 1/2) months, until repaired or the facility is replaced. Examples of Class 3 leaks are: any reading of fifty percent (50%) or less gas-in-air located between five and fifteen feet (5'–15') from a building; any reading located between fifteen and fifty feet (15'–50') from a building, except those defined in Class 4; a reading less than the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 or Class 2 which, in the judgment of the supervisor at the scene, is regarded as requiring Class 3 priority.

4. Class 4 leak is a confined or localized leak which is completely nonhazardous. No further action is necessary.

(15) Replacement Programs.

(D) Replacement Program—Cast Iron.

1. Operators who have cast iron transmission lines, feeder lines, or mains shall develop a replacement program to be submitted with an explanation to the commission by May 1, 1990, for commission review and approval. This systematic replacement program shall be prioritized to identify and eliminate pipelines in those areas that present the greatest potential for hazard in an expedited manner. These high priority replacement areas would include, but not be limited to:

A. High-pressure cast iron pipelines located beneath pavement which is continuous to building walls;

B. High-pressure cast iron pipelines located near concentrations of the general public such as Class 4 locations, business districts and schools;

C. Small diameter cast iron pipelines;

D. Areas where extensive excavation, blasting or construction activities have occurred in close proximity to cast iron pipelines;

E. Sections of cast iron pipeline that have had sections replaced as a result of requirements in subsection (13)(Z) [*(192.755)*];

F. Sections of cast iron pipeline that lie in areas of planned future development projects, such as city, county, or state highway construction/relocations, urban renewal, etc.; and

G. Sections of cast iron pipeline that exhibit a history of leakage or graphitization.

2. A long-term, organized replacement program and schedule shall also be established for cast iron pipelines not identified by the operator as being high priority.

3. Operators who have cast iron service lines shall replace them by December 31, 1991.

(16) Pipeline Integrity Management for Transmission Lines.

(A) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, [*2021*]**2023**, and the subsequent amendments 192-[*130*]**135** (published in *Federal Register* on [*April 8, 2022*]**April 29, 2024**, page [*87*]**89** FR [*20940*]**33264**)[*,*]**and** 192-[*132*]**138** (published in Federal Register on [*August 24, 2022*]**January 15, 2025**, page [*87*]**90** FR [*52224*]**3713**), [*and 192-133 (published in the Federal Register on April 24, 2023, page 88 FR 24708),*] the federal regulations in 49 CFR part 192, subpart O, and in 49 CFR part 192, appendices E and F, are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to subpart O and appendices E and F to 49 CFR part 192.

(B) The *Code of Federal Regulations* and the *Federal Register* are published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, [*2021*]**2023**, version of 49 CFR part 192 is available at [*https://www.govinfo.gov/#citation*]**https://www.govinfo.gov/content/pkg/CFR-2023-title49-vol3/pdf/CFR-2023-title49-vol3-part192.pdf**. The *Federal Registe*r publication on page [*87*]**89** FR [20940]**33264** is available at [*https://www.govinfo.gov/content/pkg/FR-2022-04-08/pdf/2022-07133.pdf*] **https://www.govinfo.gov/content/pkg/FR-2024-04-29/pdf/2024-08624.pdf**. The *Federal Register* publication on page [*87*]**90** FR [*52224*]**3713** is available at [*https://www.govinfo.gov/content/pkg/FR-2022-08-24/pdf/2022-17031.pdf*]**https://www.govinfo.gov/content/pkg/FR-2025-01-15/pdf/2025-00073.pdf**. [*The Federal Register publication on page 88 FR 24708 is available at https://www.govinfo.gov/content/pkg/FR-2023-04-24/pdf/2023-08548.pdf.*]

(17) Gas Distribution Pipeline Integrity Management (IM).

(B) What Do the Regulations in this Section Cover? (192.1003)

1. General. Unless exempted in paragraph (17)(B)2., this section prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this rule, including liquefied petroleum gas systems. A gas distribution operator must follow the requirements in section (17).

2. Exceptions. Section (17) does not apply to—

A. Individual service lines directly connected to a production line or a gathering line other than a regulated onshore gathering line as determined in [*subsection*]**paragraph** (1)(E)**1.** [*of this rule (192.8)*];

B. Individual service lines directly connected to either a transmission or regulated gathering pipeline and maintained in accordance with paragraphs (13)(BB)1. and 2. of this rule [*(192.740(a) and (b))*]; and

C. Master meter systems.

Appendix B to 20 CSR 4240-40.030
Appendix B—Qualification of Pipe and Components

I. List of Specifications.

A. Listed Pipe Specifications.

ANSI/API Specification 5L—Steel pipe, "[*API Specification for*] Line Pipe" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A106/A106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A672/A672M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A691/A691M—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513—"Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F2817–10—''Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

B. Other Listed Specifications for Components.

ASME B16.40–2008—''Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513—''Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1055–98 (2006)—''Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).
ASTM F1924–12—''Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).
ASTM F1948–12—''Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing'' (incorporated by reference, in 49 CFR 192.7 and adopted in subsection (1)(D)).
ASTM F1973–13—''Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).
ASTM F2817–10—''Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.030. Original rule filed Feb. 23, 1968, effective March 14, 1968. Amended: Filed Dec. 28, 1970, effective Jan. 6, 1971. Amended: Filed Dec. 29, 1971, effective Jan. 7, 1972. Amended: Filed Feb. 16, 1973, effective Feb. 26, 1973. Amended: Filed Feb. 1, 1974, effective Feb. 11, 1974. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Emergency amendment filed Jan. 17, 1977, effective Jan. 27, 1977, expired May 27, 1977. Amended: Filed Jan. 17, 1977, effective June 1, 1977. Emergency amendment filed March 15, 1978, effective March 25, 1978, expired July 23, 1978. Amended: Filed March 15, 1978, effective July 13, 1978. Amended: Filed July 5, 1978, effective Oct. 12, 1978. Amended: Filed July 13, 1978, effective Oct. 12, 1978. Amended: Filed Jan. 12, 1979, effective April 12, 1979. Amended: Filed May 27, 1981, effective Nov. 15, 1981. Amended: Filed Dec. 28, 1981, effective July 15, 1982. Amended: Filed Jan. 25, 1983, effective June 16, 1983. Amended: Filed Jan. 17, 1984, effective June 15, 1984. Amended: Filed Nov. 16, 1984, effective April 15, 1985. Amended: Filed Jan. 22, 1986, effective July 18, 1986. Amended: Filed May 4, 1987, effective July 24, 1987. Amended: Filed Feb. 2, 1988, effective April 28, 1988. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Dec. 14, 2000, effective May 30, 2001. Amended: Filed Oct. 15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May 30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019. Amended: Filed Dec. 12, 2019, effective July 30, 2020. Amended: Filed June 29, 2021, effective Jan. 30, 2022. Amended: Filed July 29, 2022, effective Feb. 28, 2023. Amended: Filed July 27, 2023, effective March 30, 2024. **Amended: Filed March 19, 2025.***

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

Fields v. Missouri Power & Light Company*, 374 SW2d 17 (Mo. 1963). Violations of general law, municipal ordinances, rules of the Public Service Commission and the like are considered and held to be negligence per se. Here, violation of a rule of a private gas company filed with the P.S.C. cannot result in the creation of a cause of action in favor of another person separate and apart from an action based on common law negligence.*

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE TO SUBMIT COMMENTS AND NOTICE OF PUBLIC HEARING: Anyone may file comments in support of or in opposition to this proposed amendment with the Missouri Public Service Commission, Nancy Dippell, Secretary of the Commission, P.O. Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or be before June 2, 2025, and should include a reference to Commission File No. GX-2025-0249. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing regarding this proposed rule is scheduled for June 6, 2025, at 11 a.m., in Room 310 of the Governor's Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support or in opposition to this proposed amendment, and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.