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 commission is amending sections (1), (4), (7), (9), (12), (13), (16), and Appendix E.

*PURPOSE: This amendment modifies the rule to address amendments of 49 CFR part 192 promulgated between January 2022 and December 2022, technical corrections published in the **Federal Register** on April 24, 2023, page 88 FR 24708, and corrects typographical errors.*

(1) General.

(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 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;

*[6.]***7.** Commission means the Missouri Public Service Commission;

*[7.]***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;

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

*[9.]***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;

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

*[11.]***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;

*[12.]***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;

*[13.]***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));

*[14.]***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;

*[15.]***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);

*[16.]***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;

*[17.]***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;

*[18.]***22.** Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;

*[19.]***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 HV$_{10}$);

*[20.]***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;

*[21.]***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;

*[22.]***29.** Listed specification means a specification listed in subsection I. of Appendix B, which is included herein (at the end of this rule);

*[23.]***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;

*[24.]***31.** Main means a distribution line that serves as a common source of supply for more than one (1) service line;

*[25.]***32.** Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of one (1) year;

*[26.]***33.** Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this rule;

*[27.]***34**. 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_classifications/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;

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

36. 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;

*[29.]***37**. Operator means a person who engages in the transportation of gas;

*[30.]***38.** 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;

*[31.]***39.** 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);

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

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

*[34.]***42.** 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;

*[35.]***43.** 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;

*[36.]***44.** 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;

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

46. 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;

*[38.]***47.** 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;

*[39.]***48.** 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;

*[40.]***49.** 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));

*[41.]***50.** 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;

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

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

A. Transports gas from a gathering **pipe**line 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. *[Operates at a hoop stress]* **Has an MAOP** of twenty percent (20%) or more of SMYS; *[or]*

C. Transports gas within a storage field; **or**

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

*[44.]***53.** 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;

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

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

*[47.]***56.** 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;

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

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

59. 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 (1) 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

*[50.]***60**. 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, *[2020]* **2021**, and the subsequent amendment 192-*[128]* **132** (published in *Federal Register* on *[January 11, 2021]* **August 24, 2022**, page *[86]* **87** FR *[2210]* **52224**), 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, *[2020]* **2021**, version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. The *Federal Register* publication on page *[86]* **87** FR *[2210]* **52224** is available at *[https://www.govinfo.gov/content/pkg/FR-2021-01-11/pdf/2021-00208.pdf]* **https://www.govinfo.gov/content/pkg/FR-2022-08-24/pdf/2022-17031.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. (192.8 and 192.9)

1. *[As set forth in the Code of Federal Regulations (CFR) dated October 1, 2020, and the subsequent amendments 192-129 (published in Federal Register on November 15, 2021, page 86 FR 63266) and 192-131 (published in Federal Register on May 4, 2022, page 86 FR 26296), the federal regulations at 49 CFR 192.8 and 192.9 are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR 192.8 and 192.9.]* **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 subparagraph (1)(E)1.B.

(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 paragraph (1)(E)1. 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 thousand feet (1000') (305 m) of pipeline and including five (5) or more dwellings.	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.
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.

D. 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.

E. 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. *[The Code of Federal Regulations is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 2020, version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. The Federal Register publication on page 86 FR 63266 is available at https://www.govinfo.gov/content/pkg/FR-2021-11-15/pdf/2021-24240.pdf.]* **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.

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., (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., (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 subsection (12)(J);

(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 paragraphs (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 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 paragraph (1)(E)2., 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 paragraph (1)(E)2.

(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 paragraph (1)(E)2., 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 paragraph (1)(E)2.

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 paragraph (1)(E)2.

[3. The regulations at 49 CFR 192.8 and 192.9 provide the requirements for gathering lines. The requirements for offshore lines are not applicable to Missouri.

4. For purposes of this subsection, the following substitutions should be made for certain references in the federal pipeline safety regulations incorporated by reference in paragraph (1)(E)1.

A. The references to "part 191 of this chapter" in 49 CFR 192.8 should refer to "20 CSR 4240-40.020" instead.

B. The references to "section 192.18" in 49 CFR 192.8 and 192.9 should refer to "subsection (1)(M) of this rule" instead.]

(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 no apply until April 14, 2006 (see (1)(E))	March 15, 2007
Regulated onshore gathering pipeline to which this rule did no 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.

*[4.]***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.

(M) How to Notify PHMSA and Designated Commission Personnel. (192.18)

1. An operator must provide any notification required by this rule by—

A. Sending the notification by electronic mail to InformationResourcesManager@dot.gov; or

B. Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave. SE, Washington, DC 20590.

2. An operator must also notify designated commission personnel by electronic mail to PipelineSafetyProgramManager@psc.mo.gov or by mail to Pipeline Safety Program Manager, Missouri Public Service Commission, PO Box 360, Jefferson City, MO 65102.

3. Unless otherwise specified, if *[the notification is made]* **an operator submits**, pursuant to (1)(E), **(1)(G)4., (4)(U)4.–6., (7)(J)4.,** (9)(G)**7.**, (10)(K)2., (12)(E)5.D., *[and]* **(12)(E)5.**E., (12)(M)3.B., (12)(U)3.B.(III), *[and]* **(12)(U)**3.F., (12)(V)2.C., **(12)(X)1., (12)(X)2.C., (12)(X)2.D., (12)(Z)3., (13)(U)5.A.,** (13)(DD)3.G., (13)(EE)4.C.(IV), *[and]* **(13)(EE)**5.B.(I)(e), **(13)(GG)5.B., (13)(GG)5.C.,** 49 CFR 192.921(a)(7) (incorporated by reference in section (16)), or 49 CFR 192.937(c)(7) (incorporated by reference in section (16)), *[to]* **a notification for** use **of** a different integrity assessment method, analytical method, **compliance period,** sampling approach, **pipeline material,** or technique (*[i.e.]* **e.g.**, "other technology" *[that differs from that prescribed]* **or "alternative equivalent technology"**) **than otherwise prescribed** in those requirements, *[the operator must notify]* **that notification must be submitted to** PHMSA **for review** at least ninety (90) days in advance of using the *["]*other *[technology"]* **method, approach, compliance timeline, or technique**. An operator may proceed to use the *["]*other *[technology"]* **method, approach, compliance timeline, or technique** ninety-one (91) days after *[submittal of]* **submitting** the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the *[proposed use of "other technology"]* **proposal** or that PHMSA requires additional time to conduct its review.

(4) Design of Pipeline Components.

(U) Transmission Line Valves. (192.179)

1. Each transmission line must have sectionalizing block valves spaced as follows, unless in a particular case the administrator finds that alternative spacing would provide an equivalent level of safety:

A. Each point on the pipeline in a Class 4 location must be within two and one-half (2 1/2) miles (4 kilometers) of a valve;

B. Each point on the pipeline in a Class 3 location must be within four (4) miles (6.4 kilometers) of a valve;

C. Each point on the pipeline in a Class 2 location must be within seven and one-half (7 1/2) miles (12 kilometers) of a valve; and

D. Each point on the pipeline in a Class 1 location must be within ten (10) miles (16 kilometers) of a valve.

2. Each sectionalizing block valve on a transmission line must comply with the following:

A. The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage; and

B. The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

3. Each section of a transmission line between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

4. For transmission pipeline segments with diameters

greater than or equal to six inches (6") that are constructed after April 10, 2023, the operator must install rupture-mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this subsection. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (4)(U)6. All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of subsections (12)(X) and (12)(Z). Exempted from this paragraph's installation requirements are pipeline 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)), of one hundred fifty feet (150') or less. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in subsection (1)(M), that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular new pipeline.

5. For entirely replaced transmission pipeline segments, as defined in subsection (1)(B), with diameters greater than or equal to six inches (6") and that are installed after April 10, 2023, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this subsection. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (4)(U)6. All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of subsections (12)(X) and (12)(Z). The requirements of this paragraph apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. This paragraph's installation requirements do not apply to pipe segments in Class 1 or Class 2 locations that have a 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'). An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in subsection (1)(M), that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project.

6. If an operator elects to use alternative equivalent technology in accordance with paragraph (4)(U)4. or (4)(U)5., the operator must notify PHMSA in accordance with the procedures in subsection (1)(M). The operator must include a technical and safety evaluation in its notice to PHMSA. Valves that are installed as alternative equivalent technology must comply with subsections (12)(X) and (12)(Z). An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to PHMSA a demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, and use of such valve would not require a notification to PHMSA in accordance with subsection (1)(M), but it must comply with subsection (12)(Z).

7. The valve spacing requirements of paragraph (4)(U)1. do not apply to pipe replacements on a pipeline if the distance between each point on the pipeline and the nearest valve does not exceed—

A. Four (4) miles in Class 4 locations, with a total spacing between valves no greater than eight (8) miles;

B. Seven and one-half (7 1/2) miles in Class 3 locations, with a total spacing between valves no greater than fifteen (15) miles; or

C. Ten (10) miles in Class 1 or 2 locations, with a total spacing between valves no greater than twenty (20) miles.

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

(J) Installation of Pipe in a Ditch. (192.319)

1. When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of twenty percent (20%) or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

2. When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that—

A. Provides firm support under the pipe; and

B. Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

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

4. An operator must notify PHMSA in accordance with subsection (1)(M) at least ninety (90) days in advance of using other technology to assess integrity of the coating under paragraph (7)(J)3.

5. An operator of a steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within six (6) months of completing the assessment that identified the deficiency. An operator must repair any coating damage classified as severe (voltage drop greater than sixty percent (60%) for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)) within six (6) months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed six (6) months after the receipt of permits.

6. An operator of a steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (7)(J)3.–5.

(9) Requirements for Corrosion Control.

(G) External Corrosion Control—Protective Coating. (192.461)

1. Each external protective coating applied for the purpose of external corrosion control must—

A. Be applied on a properly prepared surface;

B. Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

C. Be sufficiently ductile to resist cracking;

D. Have sufficient strength to resist damage due to handling **(including but not limited to transportation, installation, boring, and backfilling)** and soil stress; and

E. Have properties compatible with any supplemental cathodic protection.

2. Each external protective coating must also have low moisture absorption and high electrical resistance.

3. Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

4. Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

5. If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

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

7. An operator must notify PHMSA in accordance with subsection (1)(M) at least ninety (90) days in advance of using other technology to assess integrity of the coating under paragraph (9)(G)6.

8. An operator of a steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within six (6) months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than sixty percent (60%) for DCVG or 70 dBμV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)) within six (6) months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed six (6) months after the receipt of permits.

9. An operator of a steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (9)(G)6.–8.

(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 *[shall take]* **must** prompt**ly** *[remedial action to]* correct any deficiencies indicated by the *[monitoring set forth in]* **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.

(M) External Corrosion Control—Interference Currents. (192.473)

1. Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of these currents.

2. Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

3. For gas transmission pipelines, the program required by paragraph (9)(M)1. must include—

A. Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures;

B. Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;

C. Development of a remedial action plan to correct any instances where interference current is greater than or equal to one hundred (100) amps per meter squared alternating current (AC), or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and

D. Application for any necessary permits within six (6) months of completing the interference survey that identified the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within fifteen (15) months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed six (6) months, after obtaining any necessary permits.

(S) Remedial Measures—Transmission Lines. (192.485)

1. General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering test and analysis show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

2. Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

3. **Calculating remaining strength.** Under paragraphs (9)(S)1. and (9)(S)2., the strength of pipe based on actual remaining wall thickness *[may]* **must** be determined *[by the procedure in ASME/ANSI B31G (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) or the procedure in PRCI PR-3-805 (R-STRENG) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures]* **and documented in accordance with subsection (13)(EE)**.

(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.

(12) Operations.

(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.

(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. *[Causing an]* **Taking necessary actions, including but not limited to** emergency shutdown *[and]***, valve shut-off, or** pressure reduction**,** in any section of the operator's pipeline system**,** *[necessary]* to minimize hazards **of released gas** to life**,** *[or]* 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 *[and coordinating with them]* **to coordinate and share information to determine the location of the emergency, including** both planned responses and actual responses during an emergency**. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in 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; *[and]*

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 *[shall]* **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.

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

1. Post-failure and incident procedures. Each operator *[shall]* **must** establish **and follow** procedures for **investigating and** analyzing *[accidents and]* failures **and federal incidents as defined in 20 CSR 4240-40.020(2)(D)**, including **sending** the *[selection of samples of the]* failed *[facility]* **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 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 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 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)]* **paragraph (1)(E)2.**) 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)]* **paragraph (1)(E)2.**) 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 (1)(E) 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 *[(192.18)]*. 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.

(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 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 subsections (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 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 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).

3. Manual operation upon identification of a rupture. Operators using a manual valve as an alternative equivalent technology as authorized pursuant to subsections (1)(M) and (4)(U) must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shut-off in accordance with this subsection and subsection (12)(Z). Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under paragraph (12)(Z)2.

(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.

(Z) Transmission Lines—Response to a Rupture; Capabilities of Rupture-Mitigation Valves (RMVs) or Alternative Equivalent Technologies. (192.636)

1. Scope. The requirements in this subsection apply to rupture-mitigation valves (RMVs), as defined in subsection (1)(B), or alternative equivalent technologies, installed pursuant to paragraphs (4)(U)4.–6. and subsection (12)(X).

2. Rupture identification and valve shut-off time. An operator must, as soon as practicable but within thirty (30) minutes of rupture identification (see subparagraph (12)(J)1.L.), fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture.

3. Open valves. An operator may leave an RMV or alternative equivalent technology open for more than thirty (30) minutes, as required by paragraph (12)(Z)2., if the operator has previously established in its operating procedures and demonstrated within a notice submitted under subsection (1)(M) for PHMSA review, that closing the RMV or alternative equivalent technology would be detrimental to public safety. The request must have been coordinated with appropriate local emergency responders, and the operator and emergency responders must

determine that it is safe to leave the valve open. Operators must have written procedures for determining whether to leave an RMV or alternative equivalent technology open, including plans to communicate with local emergency responders and minimize environmental impacts, which must be submitted as part of its notification to PHMSA.

4. Valve monitoring and operation capabilities. An RMV, as defined in subsection (1)(B), or alternative equivalent technology, must be capable of being monitored or controlled either remotely or by on-site personnel as follows:

A. Operated during normal, abnormal, and emergency operating conditions;

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

C. Have a back-up power source to maintain SCADA systems or other remote communications for remote-control valve (RCV) or automatic shutoff valve (ASV) operational status, or be monitored and controlled by on-site personnel.

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

6. Flow modeling for automatic shutoff valves. Prior to using an ASV as an RMV, an operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within thirty (30) minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with subsection (1)(B) and subsection (12)(Z). The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not exceeding a period of fifteen (15) months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. If operating conditions change that could affect the ASV set pressures and the thirty- (30-) minute valve closure time after notification of potential rupture, as defined in subsection (1)(B), an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with subsection (13)(U). The flow model must include a time/pressure chart for the segment containing the ASV if a rupture occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the thirty- (30-) minute valve closure time unachievable.

7. Manual valves in non-HCA, Class 1 locations. For pipeline segments in a Class 1 location that do not meet the definition of a high consequence area (HCA), an operator submitting a notification pursuant to subsections (1)(M) and (4)(U) for use of manual valves as an alternative equivalent technology may also request an exemption from the requirements of paragraph (12)(Z)2.

(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*[: The]* **for gathering lines. For gathering lines subject to this subsection in accordance with subsection (1)(E), an** operator must make permanent repairs as soon as feasible; *[and]*

B. Non-integrity management repairs for transmission lines. Except for gathering lines exempted from this subsection in accordance with subsection (1)(E), 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

*[B.]***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.

(U) Valve Maintenance—Transmission Lines. (192.745)

1. Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding fifteen (15) months but at least once each calendar year.

2. Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

3. For each remote-control valve (RCV) installed in accordance with subsection (4)(U) or subsection (12)(X), an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with paragraphs (12)(T)3. and 5.

4. For each alternative equivalent technology installed on a pipeline under paragraphs (4)(U)4. or (4)(U)5. or subsection (12)(X) that is manually or locally operated (i.e., not a rupture-mitigation valve (RMV), as that term is defined in subsection (1)(B))—

A. Operators must achieve a valve closure time of thirty (30) minutes or less, pursuant to paragraph (12)(Z)2., through an initial drill and through periodic validation as required in subparagraph (13)(U)4.B. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shutoff time as being less than or equal to thirty (30) minutes after rupture

identification;

B. Within each pipeline system and within each operating or maintenance field work unit, operators must randomly select a valve serving as an alternative equivalent technology in lieu of an RMV for an annual thirty- (30-) minute-total response time validation drill that simulates worst-case conditions for that location to ensure compliance with subsection (12)(Z). Operators are not required to close the valve fully during the drill; a minimum twenty-five percent (25%) valve closure is sufficient to demonstrate compliance with drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, with intervals not to exceed fifteen (15) months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph;

C. If the thirty- (30-) minute-maximum response time cannot be achieved during the drill, the operator must revise response efforts to achieve compliance with subsection (12)(Z) as soon as practicable but no later than twelve (12) months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (13)(U)5. within seven (7) days of a failed drill;

D. Based on the results of response-time drills, the operator must include lessons learned in—

(I) Training and qualifications programs;

(II) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and

(III) Any other areas identified by the operator as needing improvement; and

E. The requirements of paragraph (13)(U)4. do not apply to manual valves that, pursuant to paragraph (12)(Z)7., have been exempted from the requirements of paragraph (12)(Z)2.

5. Each operator must develop and implement remedial measures to correct any valve installed on a pipeline under paragraphs (4)(U)4. or (4)(U)5. or subsection (12)(X) that is indicated to be inoperable or unable to maintain effective shut-off as follows:

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

B. Designate an alternative valve acting as an RMV within seven (7) calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Such valves are not required to comply with the valve spacing requirements of this rule.

6. An operator using an ASV as an RMV, in accordance with subsections (1)(B), (4)(U), (12)(X), and (12)(Z), must document and confirm the ASV shut-in pressures, in accordance with paragraph (12)(Z)6., on a calendar year basis not to exceed fifteen (15) months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required, on a calendar year basis not to exceed fifteen (15) months.

(DD) Transmission Lines: Assessments Outside of High Consequence Areas. (192.710)

1. Applicability. This subsection applies to steel transmission pipelines segments with a maximum allowable operating pressure of greater than or equal to thirty percent (30%) of the specified minimum yield strength and are located in—

A. A Class 3 or Class 4 location; or

B. A "moderate consequence area" as defined in subsection (1)(B), if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (i.e., "smart pig"); and

C. This subsection does not apply to a pipeline segment located in a "high consequence area" as defined in 49 CFR 192.903 (incorporated in section (16)).

2. General.

A. Initial assessment. An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed ten (10) years after the pipeline segment first meets the conditions of paragraph (13)(DD)1. (e.g., due to a change in class location or the area becomes a moderate consequence area), whichever is later.

B. Periodic reassessment. An operator must perform periodic reassessments at least once every ten (10) years, with intervals not to exceed one*[-]*hundred twenty-six (126) months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

C. Prior assessment. An operator may use a prior assessment conducted before July 1, 2020, as an initial assessment for the pipeline segment, if the assessment met the section (16) requirements for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in subparagraph (13)(DD)2.B. calculated from the date of the prior assessment.

D. MAOP verification. An integrity assessment conducted in accordance with the requirements of paragraph (12)(U)3. for establishing MAOP may be used as an initial assessment or reassessment under this subsection.

3. Assessment method. The initial assessments and the reassessments required by paragraph (13)(DD)2. must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one (1) or more of the following methods:

A. Internal inspection. Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (e.g., dents, gouges, and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with subsection (9)(X);

B. Pressure test. Pressure test conducted in accordance with section (10). The use of section (10) pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents, and other forms of mechanical damage;

C. Spike hydrostatic pressure test. A spike hydrostatic pressure test conducted in accordance with subsection (10)

(K). A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

D. Direct examination. Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

E. Guided Wave Ultrasonic Testing. Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F to 49 CFR part 192 (incorporated in section (16));

F. Direct assessment. Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in 49 CFR 192.923 and with the applicable requirements specified in 49 CFR 192.925, 192.927, and 192.929 (incorporated in section (16)); or

G. "Other technology." "Other technology" that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the "other technology" in accordance with subsection (1)(M) *[(192.18)]*.

4. Data analysis. An operator must analyze and account for the data obtained from an assessment performed under paragraph (13)(DD)3. to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

5. Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than one hundred eighty (180) days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that one hundred eighty (180) days is impracticable.

6. Remediation. An operator must comply with the requirements in subsections (9)(S), (13)(G), *[and]* (13)(H), **(13)(EE), and (13)(GG)**, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

7. Analysis of information. An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs (13)(DD)1. through 6.

(EE) Analysis of Predicted Failure Pressure **and Critical Strain Level**. (192.712)

1. Applicability. Whenever required by this rule, operators of steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this subsection.

2. Corrosion metal loss. When analyzing corrosion metal loss under this **sub**section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)); R–STRENG (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

A. If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in paragraph (13)(EE)2. introductory text, the operator must notify PHMSA in advance in accordance with subsection (1)(M).

B. The notification provided for by subparagraph (13)(EE)2.A. must include a comparison of its predicted failure pressures to R–STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.

3. *[(Reserved)]* **Dents and other mechanical damage. To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:**

A. Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion;

B. Review high-resolution magnetic flux leakage (HR–MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections;

C. Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data;

D. Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape;

E. Identify and quantify all previous and present significant loads acting on the dent;

F. Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods;

G. The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances;

H. Dents with a depth greater than ten percent (10%) of the pipe outside diameter or with geometric strain levels that exceed the lesser of ten percent (10%) or exceed the critical strain for the pipe material properties must be remediated in accordance with subsection (13)(H), subsection (13)(GG), or 49 CFR 192.933 (this federal regulation is incorporated by reference and adopted in

section (16)), as applicable;

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

J. If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in subsection (13)(H), subsection (13)(GG), or 49 CFR 192.933 (this federal regulation is incorporated by reference and adopted in section (16)), as applicable; and

K. An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph (13)(EE)3. must submit advance notification to PHMSA, with the relevant procedures, in accordance with subsection (1)(M).

4. Cracks and crack-like defects.

A. Crack analysis models. When analyzing cracks and crack-like defects under this subsection, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle, or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).

B. Analysis for crack growth and remaining life. If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

(I) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in subparagraph (13)(EE)5.B. must be used.

(II) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle, or both) and boundary condition used (pressure test, ILI, or other).

(III) An operator must re-evaluate the remaining life of the pipeline before fifty percent (50%) of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before fifty percent (50%) of the remaining life calculated in the most recent evaluation has expired.

C. Cracks that survive pressure testing. For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in subparagraph (13)(EE)4.A. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one (1) of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

(I) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(II) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in subsection (12)(E);

(III) A full size equivalent Charpy v-notch upper-shelf toughness level of one hundred twenty (120) foot-pounds; or

(IV) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with subsection (1)(M) ***[(192.18)]***.

5. Data. In performing the analyses of predicted or assumed anomalies or defects in accordance with this subsection, an operator must use data as follows.

A. An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using in situ direct measurements.

B. The analyses performed in accordance with this subsection must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through subsection (12)(E). Until documented material properties are available, the operator shall use conservative assumptions as follows:

(I) Material toughness. An operator must use one of the following for material toughness:

(a) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(b) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in subsection (12)(E);

(c) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 foot-pounds for body cracks and 4.0 foot-pounds for cold weld, lack of fusion, and selective seam weld corrosion defects;

(d) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 foot-pounds for body cracks and 1.0 foot-pound for cold weld, lack of fusion, and selective seam weld corrosion; or

(e) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with subsection (1)(M) *[(192.18)]* and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions;

(II) Material strength. An operator must assume one of the following for material strength:

(a) Grade A pipe (30,000 psi); or

(b) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure; and

(III) Pipe dimensions and other data. Until pipe wall thickness, diameter, or other data are determined and documented in accordance with subsection (12)(E), the operator must use values upon which the current MAOP is based.

6. Review. Analyses conducted in accordance with this subsection must be reviewed and confirmed by a subject matter expert.

7. Records. An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this subsection. Records must document justifications, deviations, and determinations made for the following, as applicable:

A. The technical approach used for the analysis;

B. All data used and analyzed;

C. Pipe and weld properties;

D. Procedures used;

E. Evaluation methodology used;

F. Models used;

G. Direct in situ examination data;

H. In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;

I. Pressure test data and results;

J. In-the-ditch assessments;

K. All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

L. All finite element analysis results;

M. The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

N. The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

O. Safety factors used for fatigue life and/or predicted failure pressure calculations;

P. Reassessment time interval and safety factors;

Q. The date of the review;

R. Confirmation of the results by qualified technical subject matter experts; and

S. Approval by responsible operator management personnel.

8. Reassessments. If an operator uses an engineering critical assessment method in accordance with paragraphs (13)(EE)3. or 4. to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:

A. If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of seven (7) years in accordance with 49 CFR 192.939(a) (this federal regulation is incorporated by reference and adopted in section (16)), unless the safety factor is expected to go below what is specified in paragraph (13)(EE)3. or paragraph (13)(EE)4.; and

B. If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of ten (10) years in accordance with paragraph (13)(DD)2., unless the anomaly safety factor is expected to go below what is specified in paragraph (13)(EE)3. or paragraph (13)(EE)4.

(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 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in 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 (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;

(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 (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).

(16) Pipeline Integrity Management for Transmission Lines.

(A) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, *[2019]* **2021**, and the subsequent amendment**s** 192-*[125]* **130** (published in *Federal Register* on *[October 1, 2019]* **April 8, 2022**, page *[84]* **87** FR *[52180]* **20940**), **192-132 (published in *Federal Register* on August 24, 2022, page 87 FR 52224), 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, *[2019]* **2021,** version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. The *Federal Register* publication on page *[84]* **87** FR *[52180]* **20940** is available at *[https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf]* **https://www.govinfo.gov/content/pkg/FR-2022-04-08/pdf/2022-07133.pdf. The *Federal Register* publication on page 87 FR 52224 is available at https://www.govinfo.gov/content/pkg/FR-2022-08-24/pdf/2022-17031.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.**

(F) For the purposes of this section, the following substitutions should be made for certain references in the federal pipeline safety regulations that are incorporated by reference in subsection (16)(A).

1. *[(Reserved)]* **In 49 CFR 192.901 through 192.951, the references to "incorporated by reference, see section 192.7" should refer to "incorporated by reference in 49 CFR 192.7 and adopted in 20 CSR 4240-40.030(1)(D)" instead.**

2. In 49 CFR 192.901, 192.917, and 192.935, the references to "this part" should refer to "this rule" instead.

3. In 49 CFR 192.903 and 192.927, the references to "section 192.3" should refer to "20 CSR 4240-40.030(1)(B)" instead.

4. In 49 CFR 192.903, the reference to "section 192.5" should refer to "20 CSR 4240-40.030(1)(C)" instead.

5. In 49 CFR 192.911, the reference to "section 192.13(d)" should refer to "20 CSR 4240-40.030(1)(G)4." instead.

*[2.]***6.** In 49 CFR 192.917*[(e)(5)]*, the reference to "part 192" should refer to "20 CSR 4240-40.030" instead.

7. In 49 CFR 192.917, the reference to "a reportable incident, as defined in section 191.3" should refer to "a reportable federal incident, as defined in 20 CSR 4240-40.020(2)" instead.

8. In 49 CFR 192.917, the reference to "section 192.113" should refer to "20 CSR 4240-40.030(3)(G)" instead.

9. In 49 CFR 192.917, the reference to "section 192.459" should refer to "20 CSR 4240-40.030(9)(F)" instead.

10. In 49 CFR 192.917, the reference to "section 192.605(c)" should refer to "20 CSR 4240-40.030(12)(C)3." instead.

11. In 49 CFR 192.917, the reference to "section 192.617" should refer to "20 CSR 4240-40.030(12)(L)" instead.

12. In 49 CFR 192.917 and 192.921, the references to "subpart J" should refer to "20 CSR 4240-40.030(10)" instead.

13. In 49 CFR 192.917, 192.921, 192.927, 192.933, 192.937, and 192.939, the references to "section 192.18" should refer to "20 CSR 4240-40.030(1)(M)" instead.

14. In 49 CFR 192.917, 192.929, and 192.933, the references to "section 192.712" should refer to "20 CSR 4240-40.030(13)(EE)" instead.

15. In 49 CFR 192.921, 192.929, and 192.937, the references to "section 192.506" should refer to "20 CSR 4240-40.030(10)(K)" instead.

*[3.]***16.** In 49 CFR 192.921*[(a)(2)]* and 192.937*[(c)(2)]*, the references to "subpart J of this part" should refer to "20 CSR 4240-40.030(10)" instead.

*[4.]***17.** *[(Reserved)]* **In 49 CFR 192.921 and 192.937, the references to "section 192.624(c)" should refer to "20 CSR 4240-40.030(12)(U)3." instead.**

18. In 49 CFR 192.927, the reference to "sections 192.485 and 192.714" should refer to "20 CSR 4240-40.030(9)(S) and 20 CSR 4240-40.030(13)(GG)" instead.

19. In 49 CFR 192.927, the reference to "section 192.478" should refer to "20 CSR 4240-40.030(9)(Y)" instead.

20. In 49 CFR 192.929, the reference to "section 192.111 and 192.112" should refer to "20 CSR 4240-40.030(3)(F) and 20 CSR 4240-40.030(3)(L)" instead.

21. In 49 CFR 192.929, the reference to "section 192.506(a)" should refer to "20 CSR 4240-40.030(10)(K)1." instead.

22. In 49 CFR 192.929 and 192.933, the references to "section 192.607" should refer to "20 CSR 4240-40.030(12)(E)" instead.

23. In 49 CFR 192.929 and 192.933, the references to "section 192.611" should refer to "20 CSR 4240-40.030(12)(G)" instead.

24. In 49 CFR 192.933, the reference to "section 192.712(b)" should refer to "20 CSR 4240-40.030(13)(EE)2." instead.

25. In 49 CFR 192.933, the reference to "section 192.712(c)" should refer to "20 CSR 4240-40.030(13)(EE)3." instead.

26. In 49 CFR 192.933, the reference to "section 192.712(d)" should refer to "20 CSR 4240-40.030(13)(EE)4." instead.

27. In 49 CFR 192.933, the reference to "section 192.712(d)(3)" should refer to "20 CSR 4240-40.030(13)(EE)4.C." instead.

28. In 49 CFR 192.933, the reference to "section 192.712(e)(2)" should refer to "20 CSR 4240-40.030(13)(EE)5.B." instead.

29. In 49 CFR 192.935, the reference to "Part 192" should refer to "20 CSR 4240-40.030" instead.

*[5.]***30**. In 49 CFR 192.935*[(b)(1)(ii)]*, the reference to "an incident under part 191" should refer to "a federal incident under 20 CSR 4240-40.020" instead.

31. In 49 CFR 192.935, the reference to "an incident or safety-related condition, as those terms are defined at sections 191.3 and 191.23" should refer to "a federal incident or safety-related condition, as those terms are defined at 20 CSR 4240-40.020(2) and 20 CSR 4240-40.020(12)" instead.

32. In 49 CFR 192.935, the reference to "section 192.614 of this part" should refer to "20 CSR 4240-40.030(12)(I)" instead.

*[6.]***33**. In 49 CFR 192.935*[(d)(2)]*, the reference to "section 192.705" should refer to "20 CSR 4240-40.030(13)(C)" instead.

34. In 49 CFR 192.937, the reference to "section 192.493" should refer to "20 CSR 4240-40.030(9)(X)" instead.

*[7.]***35.** In 49 CFR 192.941*[(b)(2)(i)]*, the reference to "section 192.706" should refer to "20 CSR 4240-40.030(13)(D)" instead.

*[8.]***36.** In 49 CFR 192.945*[(a)]*, the reference**s** to "section 191.17 of this subchapter" should refer to "20 CSR 4240-40.020(10)" instead.

*[9.]***37.** In 49 CFR 192.947*[(i)]*, the reference to "a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State" should refer to "designated commission personnel" instead.

*[10.]***38.** In 49 CFR 192.951, the reference to "section 191.7 of this subchapter" should refer to "20 CSR 4240-40.020(5)(A)" instead.

Appendix E to 20 CSR 4240-40.030
Appendix E—Table of Contents—Safety Standards—Transportation of Gas by Pipeline

20 CSR 4240-40.030(1) General
(A) What Is the Scope of this Rule? (192.1)
(B) Definitions. (192.3)
(C) Class Locations. (192.5)
(D) Incorporation By Reference of the Federal Regulation at 49 CFR 192.7. (192.7)
(E) Gathering Lines. (192.8 and 192.9)
(F) Petroleum Gas Systems. (192.11)
(G) What General Requirements Apply to Pipelines Regulated Under this Rule? (192.13)
(H) Conversion to Service Subject to this Rule. (192.14)
(I) Rules of Regulatory Construction. (192.15)
(J) Filing of Required Plans, Procedures, and Programs.
(K) Customer Notification Required by Section 192.16 of 49 CFR 192. (192.16)
(L) Customer Notification, Paragraph (12)(S)2.
(M) How to Notify PHMSA and Designated Commission Personnel. (192.18)

20 CSR 4240-40.030(2) Materials
(A) Scope. (192.51)
(B) General. (192.53)
(C) Steel Pipe. (192.55)
(D) Plastic Pipe. (192.59)
(E) Marking of Materials. (192.63)
(F) Transportation of Pipe. (192.65)
(G) Records: Material Properties. (192.67)
(H) Storage and Handling of Plastic Pipe and Associated Components. (192.69)

20 CSR 4240-40.030(3) Pipe Design
(A) Scope. (192.101)
(B) General. (192.103)
(C) Design Formula for Steel Pipe. (192.105)
(D) Yield Strength (S) for Steel Pipe. (192.107)
(E) Nominal Wall Thickness (t) for Steel Pipe. (192.109)
(F) Design Factor (F) for Steel Pipe. (192.111)
(G) Longitudinal Joint Factor (E) for Steel Pipe. (192.113)
(H) Temperature Derating Factor (T) for Steel Pipe. (192.115)
(I) Design of Plastic Pipe. (192.121)
(J) *Reserved*. (192.123)
(K) Design of Copper Pipe for Repairs. (192.125)
(L) Additional Design Requirements for Steel Pipe Using

Alternative Maximum Allowable Operating Pressure. (192.112)
(M) Records: Pipe design. (192.127)

20 CSR 4240-40.030(4) Design of Pipeline Components
(A) Scope. (192.141)
(B) General Requirements. (192.143)
(C) Qualifying Metallic Components. (192.144)
(D) Valves. (192.145)
(E) Flanges and Flange Accessories. (192.147)
(F) Standard Fittings. (192.149)
(G) Tapping. (192.151)
(H) Components Fabricated by Welding. (192.153)
(I) Welded Branch Connections. (192.155)
(J) Extruded Outlets. (192.157)
(K) Flexibility. (192.159)
(L) Supports and Anchors. (192.161)
(M) Compressor Stations – Design and Construction. (192.163)
(N) Compressor Stations – Liquid Removal. (192.165)
(O) Compressor Stations – Emergency Shutdown. (192.167)
(P) Compressor Stations – Pressure Limiting Devices. (192.169)
(Q) Compressor Stations – Additional Safety Equipment. (192.171)
(R) Compressor Stations – Ventilation. (192.173)
(S) Pipe-Type and Bottle-Type Holders. (192.175)
(T) Additional Provisions for Bottle-Type Holders. (192.177)
(U) Transmission Line Valves. (192.179)
(V) Distribution Line Valves. (192.181)
(W) Vaults – Structural Design Requirements. (192.183)
(X) Vaults – Accessibility. (192.185)
(Y) Vaults – Sealing, Venting, and Ventilation. (192.187)
(Z) Vaults – Drainage and Waterproofing. (192.189)
(AA) Risers Installed After January 22, 2019. (192.204)
(BB) Valve Installation in Plastic Pipe. (192.193)
(CC) Protection Against Accidental Overpressuring. (192.195)
(DD) Control of the Pressure of Gas Delivered From Transmission Lines and High-Pressure Distribution Systems to Service Equipment. (192.197)
(EE) Requirements for Design of Pressure Relief and Limiting Devices. (192.199)
(FF) Required Capacity of Pressure Relieving and Limiting Stations. (192.201)
(GG) Instrument, Control, and Sampling Pipe and Components. (192.203)
(HH) Passage of Internal Inspection Devices. (192.150)
(II) Records: Pipeline Components. (192.205)

20 CSR 4240-40.030(5) Welding of Steel in Pipelines
(A) Scope. (192.221)
(B) General.
(C) Welding Procedures. (192.225)
(D) Qualification of Welders and Welding Operators. (192.227)
(E) Limitations on Welders and Welding Operators. (192.229)
(F) Protection From Weather. (192.231)
(G) Miter Joints. (192.233)
(H) Preparation for Welding. (192.235)
(I) Inspection and Test of Welds. (192.241)
(J) Nondestructive Testing. (192.243)
(K) Repair or Removal of Defects. (192.245)

20 CSR 4240-40.030(6) Joining of Materials Other Than by Welding
(A) Scope. (192.271)
(B) General. (192.273)
(C) Cast Iron Pipe. (192.275)
(D) Ductile Iron Pipe. (192.277)
(E) Copper Pipe. (192.279)
(F) Plastic Pipe. (192.281)
(G) Plastic Pipe – Qualifying Joining Procedures. (192.283)
(H) Plastic Pipe – Qualifying Persons to Make Joints. (192.285)
(I) Plastic Pipe – Inspection of Joints. (192.287)

20 CSR 4240-40.030(7) General Construction Requirements for Transmission Lines and Mains
(A) Scope. (192.301)
(B) Compliance With Specifications or Standards. (192.303)
(C) Inspection – General. (192.305)
(D) Inspection of Materials. (192.307)
(E) Repair of Steel Pipe. (192.309)
(F) Repair of Plastic Pipe During Construction. (192.311)
(G) Bends and Elbows. (192.313)
(H) Wrinkle Bends in Steel Pipe. (192.315)
(I) Protection From Hazards. (192.317)
(J) Installation of Pipe in a Ditch. (192.319)
(K) Installation of Plastic Pipe. (192.321)
(L) Casing. (192.323)
(M) Underground Clearance. (192.325)
(N) Cover. (192.327)
(O) Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.328)
(P) Installation of Plastic Pipelines by Trenchless Excavation. (192.329)

20 CSR 4240-40.030(8) Customer Meters, Service Regulators, and Service Lines
(A) Scope, Compliance with Specifications or Standards, and Inspections. (192.351)
(B) Service Lines and Yard Lines.
(C) Customer Meters and Regulators – Location. (192.353)
(D) Customer Meters and Regulators – Protection From Damage. (192.355)
(E) Customer Meters and Regulators – Installation. (192.357)
(F) Customer Meter Installations – Operating Pressure. (192.359)
(G) Service Lines – Installation. (192.361)
(H) Service Lines – Valve Requirements. (192.363)
(I) Service Lines – Location of Valves. (192.365)
(J) Service Lines – General Requirements for Connections to Main Piping. (192.367)
(K) Service Lines – Connections to Cast Iron or Ductile Iron Mains. (192.369)
(L) Service Lines – Steel. (192.371)
(M) Service Lines – Plastic. (192.375)
(N) New Service Lines Not in Use. (192.379)
(O) Service Lines – Excess Flow Valve Performance Standards. (192.381)
(P) Excess Flow Valve Installation. (192.383)
(Q) Manual Service Line Shut-Off Valve Installation. (192.385)
(R) Installation of Plastic Service Lines by Trenchless Excavation. (192.376)

20 CSR 4240-40.030(9) Requirements for Corrosion Control
(A) Scope. (192.451)
(B) How Does this Section Apply to Converted Pipelines and Regulated Onshore Gathering Lines? (192.452)
(C) General. (192.453)
(D) External Corrosion Control – Buried or Submerged Pipelines Installed After July 31, 1971. (192.455)
(E) External Corrosion Control – Buried or Submerged Pipelines Installed Before August 1, 1971. (192.457)
(F) External Corrosion Control – Inspection of Buried Pipeline When Exposed. (192.459)
(G) External Corrosion Control – Protective Coating. (192.461)
(H) External Corrosion Control – Cathodic Protection.

(192.463)

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

(J) External Corrosion Control—Electrical Isolation. (192.467)

(K) External Corrosion Control—Test Stations. (192.469)

(L) External Corrosion Control—Test Leads. (192.471)

(M) External Corrosion Control—Interference Currents. (192.473)

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

(O) Internal Corrosion Control—Design and Construction of Transmission Line. (192.476)

(P) Atmospheric Corrosion Control—General. (192.479)

(Q) Atmospheric Corrosion Control—Monitoring. (192.481)

(R) Remedial Measures—General. (192.483)

(S) Remedial Measures—Transmission Lines. (192.485)

(T) Remedial Measures—Distribution Lines Other Than Cast Iron or Ductile Iron Lines. (192.487)

(U) Remedial Measures—Cast Iron and Ductile Iron Pipelines. (192.489)

(V) Corrosion Control Records. (192.491)

(W) Direct Assessment. (192.490)

(X) In-line Inspection of Pipelines. (192.493)

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

20 CSR 4240-40.030(10) Test Requirements

(A) Scope. (192.501)

(B) General Requirements. (192.503)

(C) Strength Test Requirements for Steel Pipelines to Operate at a Hoop Stress of Thirty Percent (30%) or More of SMYS. (192.505)

(D) Test Requirements for Pipelines to Operate at a Hoop Stress Less Than Thirty Percent (30%) of SMYS and At or Above One Hundred (100) psi (689 kPa) gauge. (192.507)

(E) Test Requirements for Pipelines to Operate Below One Hundred (100) psi (689 kPa) gauge. (192.509)

(F) Test Requirements for Service Lines. (192.511)

(G) Test Requirements for Plastic Pipelines. (192.513)

(H) Environmental Protection and Safety Requirements. (192.515)

(I) Records. (192.517)

(J) Test Requirements for Customer-Owned Fuel Lines.

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

20 CSR 4240-40.030(11) Uprating

(A) Scope. (192.551)

(B) General Requirements. (192.553)

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

(D) Uprating—Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than Thirty Percent (30%) of SMYS—Plastic, Cast Iron, and Ductile Iron Pipelines. (192.557)

20 CSR 4240-40.030(12) Operations

(A) Scope. (192.601)

(B) General Provisions. (192.603)

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

(D) Qualification of Pipeline Personnel. (Subpart N)

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

(F) Change in Class Location—Required Study. (192.609)

(G) Change in Class Location—Confirmation or Revision of Maximum Allowable Operating Pressure. (192.611)

(H) Continuing Surveillance. (192.613)

(I) Damage Prevention Program. (192.614)

(J) Emergency Plans. (192.615)

(K) Public Awareness. (192.616)

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

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

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

(O) Maximum and Minimum Allowable Operating Pressure—Low-Pressure Distribution Systems. (192.623)

(P) Odorization of Gas. (192.625)

(Q) Tapping Pipelines Under Pressure. (192.627)

(R) Purging of Pipelines. (192.629)

(S) Providing Service to Customers.

(T) Control Room Management. (192.631)

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

(V) Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Steel Transmission Pipelines. (192.632)

(W) Change in Class Location—Change in Valve Spacing. (192.610)

(X) Transmission Lines—Valve Shut-Off for Rupture Mitigation. (192.634)

(Y) Notification of Potential Rupture. (192.635)

(Z) Transmission Lines—Response to a Rupture; Capabilities of Rupture-Mitigation Valves (RMVs) or Alternative Equivalent Technologies. (192.636)

20 CSR 4240-40.030(13) Maintenance

(A) Scope. (192.701)

(B) General. (192.703)

(C) Transmission Lines—Patrolling. (192.705)

(D) Transmission Lines—Leakage Surveys. (192.706)

(E) Line Markers for Mains and Transmission Lines. (192.707)

(F) Record Keeping.

(G) Transmission Lines—General Requirements for Repair Procedures. (192.711)

(H) Transmission Lines—Permanent Field Repair of Imperfections and Damages. (192.713)

(I) Transmission Lines—Permanent Field Repair of Welds. (192.715)

(J) Transmission Lines—Permanent Field Repair of Leaks. (192.717)

(K) Transmission Lines—Testing of Repairs. (192.719)

(L) Distribution Systems—Patrolling. (192.721)

(M) Distribution Systems—Leakage Surveys. (192.723)

(N) Test Requirements for Reinstating Service Lines and Fuel Lines. (192.725)

(O) Abandonment or Deactivation of Facilities. (192.727)

(P) Compressor Stations—Inspection and Testing of Relief Devices. (192.731)

(Q) Compressor Stations—Storage of Combustible Materials and Gas Detection. (192.735 and 192.736)

(R) Pressure Limiting and Regulating Stations—Inspection and Testing. (192.739)

(S) Pressure Limiting and Regulating Stations—Telemetering or Recording Gauges. (192.741)

(T) Pressure Limiting and Regulating Stations—Capacity of Relief Devices. (192.743)

(U) Valve Maintenance—Transmission Lines. (192.745)

(V) Valve Maintenance—Distribution Systems. (192.747)

(W) Vault Maintenance. (192.749)

(X) Prevention of Accidental Ignition. (192.751)

(Y) Caulked Bell and Spigot Joints. (192.753)
(Z) Protecting or Replacing Disturbed Cast Iron Pipelines. (192.755)
(AA) Repair of Plastic Pipe. (192.720)
(BB) Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Regulated Gathering or Transmission Pipelines. (192.740)
(CC) Joining Plastic Pipe by Heat Fusion; Equipment Maintenance and Calibration. (192.756)
(DD) Transmission Lines: Assessments Outside of High Consequence Areas. (192.710)
(EE) Analysis of Predicted Failure Pressure **and Critical Strain Level**. (192.712)
(FF) Launcher and Receiver Safety. (192.750)
(GG) Transmission Lines—Repair Criteria for Transmission Pipelines. (192.714)

20 CSR 4240-40.030(14) Gas Leaks
(A) Scope.
(B) Investigation and Classification Procedures.
(C) Leak Classifications.

20 CSR 4240-40.030(15) Replacement Programs
(A) Scope.
(B) Replacement Programs—General Requirements.
(C) Replacement Program—Unprotected Steel Service Lines and Yard Lines.
(D) Replacement Program—Cast Iron.
(E) Replacement/Cathodic Protection Program—Unprotected Steel Transmission Lines, Feeder Lines, and Mains.

20 CSR 4240-40.030(16) Pipeline Integrity Management for Transmission Lines

20 CSR 4240-40.030(17) Gas Distribution Pipeline Integrity Management (IM)
(A) What Definitions Apply to this Section? (192.1001)
(B) What Do the Regulations in this Section Cover? (192.1003)
(C) What Must a Gas Distribution Operator (Other than a Small LPG Operator) Do to Implement this Section? (192.1005)
(D) What Are the Required Elements of an Integrity Management Plan? (192.1007)
(E) *Reserved*.
(F) What Records Must an Operator Keep? (192.1011)
(G) When May an Operator Deviate from Required Periodic Inspections Under this Rule? (192.1013)
(H) What Must a Small LPG Operator Do to Implement this Section? (192.1015)

20 CSR 4240-40.030(18) Waivers of Compliance

*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. For intervening history, please consult the **Code of State Regulations**. Amended: Filed July 27, 2023.*

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 of 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, PO Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the commission's offices on or before October 1, 2023, and should include a reference to Commission Case No. GX-2023-0422. 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 amendment is scheduled for October 4, 2023, at 1 p.m., in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, MO. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of 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.