RULES OF

Department of Commerce and Insurance

Division 4240—Public Service Commission

Chapter 40—Gas Utilities and Gas Safety Standards

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

20 CSR 4240-40.015 Affiliate Transactions
(Rescinded May 30, 2025)

AUTHORITY: section 386.250, RSMo Supp. 1998, and section 393.140, RSMo 1994. This rule originally filed as 4 CSR 240-40.015. Original rule filed April 26, 1999, effective Feb. 29, 2000. Moved to 20 CSR 4240-40.015, effective Aug. 28, 2019. Rescinded: Filed Sept. 25, 2024, effective May 30, 2025.

20 CSR 4240-40.016 Marketing Affiliate Transactions
(Rescinded May 30, 2025)

AUTHORITY: section 386.250, RSMo Supp. 1998, and section 393.140, RSMo 1994. This rule originally filed as 4 CSR 240-40.016. Original rule filed April 26, 1999, effective Feb. 29, 2000. Moved to 20 CSR 4240-40.016, effective Aug. 28, 2019. Rescinded: Filed Sept. 25, 2024, effective May 30, 2025.

20 CSR 4240-40.017 HVAC Services Affiliate Transactions
(Rescinded May 30, 2025)

AUTHORITY: section 386.760.1, RSMo Supp. 1998, and section 393.140, RSMo 1994. This rule originally filed as 4 CSR 240-40.017. Original rule filed Dec. 17, 1998, effective Aug. 30, 1999. Moved to 20 CSR 4240-40.017, effective Aug. 28, 2019. Rescinded: Filed Sept. 25, 2024, effective May 30, 2025.

20 CSR 4240-40.018 Natural Gas Price Volatility Mitigation

PURPOSE: This rule represents a statement of commission policy that natural gas local distribution companies should undertake diversified natural gas purchasing activities as part of a prudent effort to mitigate upward natural gas price volatility and secure adequate natural gas supplies for their customers.

(1) Natural Gas Supply Planning Efforts to Ensure Price Stability.

(A) As part of a prudent planning effort to secure adequate natural gas supplies for their customers, natural gas utilities should structure their portfolios of contracts with various supply and pricing provisions in an effort to mitigate upward natural gas price spikes, and provide a level of stability of delivered natural gas prices.

(B) In making this planning effort, natural gas utilities should consider the use of a broad array of pricing structures, mechanisms, and instruments, including, but not limited to, those items described in (2)(A) through (2)(H), to balance market price risks, benefits, and price stability. Each of these mechanisms may be desirable in certain circumstances, but each has unique risks and costs that require evaluation by the natural gas utility in each circumstance. Financial gains or losses associated with price volatility mitigation efforts are flowed through the Purchased Gas Adjustment (PGA) mechanism, subject to the applicable provisions of the natural gas utility's tariff and applicable prudence review procedures.

(C) Part of a natural gas utility's balanced portfolio may be higher than spot market price at times, and this is recognized as a possible result of prudent efforts to dampen upward volatility.

(2) Pricing Structures, Mechanisms and Instruments:

(A) Natural Gas Storage;
(B) Fixed Price Contracts;
(C) Call Options;
(D) Collars;
(E) Outsourcing/Agency Agreements;
(F) Futures Contracts; and
(G) Financial Swaps and Options from Over the Counter Markets; and
(H) Other tools utilized in the market for cost-effective management of price and/or usage volatility.

AUTHORITY: sections 386.250, RSMo 2000 and 393.130, RSMo Supp. 2003. This rule originally filed as 4 CSR 240-40.018. Original rule filed May 1, 2003, effective Dec. 30, 2003. Moved to 20 CSR 4240-40.018, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991,1993, 1995, 1996; 393.130, RSMo 1939, amended 1967, 1969, 2002.*

20 CSR 4240-40.020 Incident, Annual, and Safety-Related Condition Reporting Requirements

PURPOSE: This rule prescribes requirements and procedures for reporting certain gas-related incidents and safety-related conditions and for filing annual reports. It applies to gas systems subject to the safety jurisdiction of the Public Service Commission.

PUBLISHER'S NOTE: The secretary of state has determined that publication of the entire text of the material that is incorporated by reference as a portion of this rule would be unduly cumbersome or expensive. This material as incorporated by reference in this rule shall be maintained by the agency at its headquarters and shall be made available to the public for inspection and copying at no more than the actual cost of reproduction. This note applies only to the reference material. The entire text of the rule is printed here.

*AGENCY NOTE: This rule is similar to the Minimum Federal Safety Standards contained in 49 CFR part 191, **Code of Federal Regulations**. Parallel citations to Part 191 are provided for gas operator convenience and to promote public safety.*

(1) Scope. (191.1)

(A) This rule prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of gas pipeline facilities and underground natural gas storage facilities located in Missouri and under the jurisdiction of the commission. This rule applies to onshore gathering lines, including Type R gathering lines as determined in 20 CSR 4240-40.030(1)(E). (192.8)

(B) Subsections (11)(B) and (11)(C) and section (12) do not apply to the onshore gathering of gas—

1. Through a pipeline that operates at less than zero (0) pound per square inch gauge (psig) (0 kPa); or
2. Through a pipeline that is not a regulated onshore gathering line.

(2) Definitions. (191.3) As used in this rule and in the PHMSA Forms referenced in this rule—

(A) Administrator means the administrator of PHMSA or his or her delegate;

(B) Commission means the Public Service Commission. Designated commission personnel means the Pipeline Safety Program Manager at the address contained in subsection (5)(E) for correspondence and means the list of staff personnel supplied to operators for telephonic notices;

(C) Confirmed discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation;

(D) Federal incident means any of the following events:

1. An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas (LNG), liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one (1) or more of the following consequences:

A. A death or personal injury necessitating inpatient hospitalization; or

B. Estimated property damage of one hundred twenty-nine thousand three hundred dollars ($129,300) or more, including loss to the operator and others, or both, but excluding the cost of gas lost; or

C. Unintentional estimated gas loss of three (3) million cubic feet or more;

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

3. An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph (2)(D)1. or (2)(D)2.

(E) Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;

(F) LNG facility means a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing liquefied natural gas;

(G) LNG plant means an LNG facility or system of LNG facilities functioning as a unit;

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

(I) Municipality means a city, village, or town;

(J) Operator means a person who engages in the transportation of gas;

(K) Person means any individual, firm, joint venture, partnership, corporation, association, county, state, municipality, political subdivision, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative of them;

(L) Pipeline or pipeline system means all parts of those physical facilities through which gas moves in transportation including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies;

(M) PHMSA means the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation;

(N) Regulated onshore gathering means a Type A, Type B, or Type C gas gathering pipeline system as determined in 20 CSR 4240-40.030(1)(E) (192.8);

(O) Reporting-regulated gathering means a Type R gathering line as determined in 20 CSR 4240-40.030(1)(E). (192.8) A Type R gathering line is subject only to this rule;

(P) 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; and

(Q) Underground natural gas storage facility (UNGSF) means a gas pipeline facility that stores natural gas in an underground facility incidental to the transportation of natural gas, including—

1. A depleted hydrocarbon reservoir, an aquifer reservoir, or a solution-mined cavern; and

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

(3) Immediate Notice of Federal Incidents. (191.5)

(A) At the earliest practicable moment following discovery, but no later than one (1) hour after confirmed discovery, each operator shall give notice, in accordance with subsection (3)(B), of each federal incident as defined in section (2) (191.3).

(B) Each notice required by subsection (3)(A) must be made to the National Response Center either by telephone to (800) 424-8802 or electronically at www.nrc.uscg.mil and must include the following information:

1. Names of operator and person making report and their telephone numbers;

2. Location of the incident;

3. Time of the incident;

4. Number of fatalities and personal injuries, if any; and

5. All other significant facts known by the operator that are relevant to the cause of the incident or extent of the damages.

(C) Within forty-eight (48) hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in subsection (3)(B) with an estimate of the amount of gas released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.

(4) Immediate Notice of Missouri Incidents.

(A) Within two (2) hours following discovery by the operator, or as soon thereafter as practicable if emergency efforts to protect life and property would be hindered, each gas operator must notify designated commission personnel by telephone of the following events within areas served by the operator:

1. An event that involves a release of gas involving the operator's actions or pipeline system, or where there is a suspicion by the operator that the event may involve a release of gas involving the operator's actions or pipeline system, and results in one (1) or more of the following consequences:

A. A death;

B. A personal injury involving medical care administered in an emergency room or health care facility, whether inpatient or outpatient, beyond initial treatment and prompt release after evaluation by a health care professional; or

C. Estimated property damage of seventeen thousand five hundred dollars ($17,500) or more, including loss to the gas operator or others, or both, and including the cost of gas lost;

2. An event that is significant, in the judgement of the operator, even though it did not meet the criteria of paragraph (4)(A)1.; or

3. An event that is reported as a Federal incident under section (3).

(B) Exceeding the two- (2-) hour notification time period in subsection (4)(A) requires submission of a written explanation of reasons with the operator's incident report when submitting the report to designated commission personnel. See section (5) for report submission requirements.

(5) Report Submission Requirements. (191.7)

(A) Reports to PHMSA.

1. An operator must submit each report required by sections (6)–(11) electronically to the Pipeline and Hazardous Materials Safety Administration at http://portal.phmsa.dot.gov/pipeline unless an alternative reporting method is authorized in accordance with subsection (5)(D).

2. A copy of each online submission to PHMSA must also be submitted concurrently to designated commission personnel. The copy submitted to designated commission personnel must be clearly marked to indicate the date of the online submission to PHMSA.

(B) Missouri incident reports.

1. This subsection applies to events that meet the criteria in subsection (4)(A) but are not a federal incident reported under subsection (5)(A). Within thirty (30) days of a telephone notification made under subsection (4)(A), each gas operator must submit the applicable U.S. Department of Transportation Form PHMSA F 7100.1, PHMSA F 7100.2, or PHMSA F 7100.3 to designated commission personnel. Additional information required in subsections (6)(B) and (9)(B) for federal incidents is also required for these events.

2. The incident report forms for gas distribution systems (PHMSA F 7100.1, revised May 2021), gas transmission and gathering pipeline systems (PHMSA F 7100.2, revised March 2022), and LNG facilities (PHMSA F 7100.3, revised April 2019) are incorporated by reference in subsection (5)(G).

(C) Safety-related conditions. An operator must submit concurrently to PHMSA and designated commission personnel a safety-related condition report required by section (12) (191.23). A safety-related condition report can be submitted by electronic mail or telefacsimile (fax) as provided for in section (13).

(D) Alternative reporting method.

1. If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at (202) 366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted, but before an authorization or denial is received.

2. A copy of each report using an alternate reporting method must also be submitted concurrently to designated commission personnel. The copy submitted to designated commission personnel must be clearly marked to indicate the date of submission to PHMSA.

(E) Address for designated commission personnel. The address for the designated commission personnel is Pipeline Safety Program Manager, Missouri Public Service Commission, PO Box 360, Jefferson City, MO 65102. The email address for designated commission personnel is PipelineSafetyProgramManager@psc.mo.gov.

(F) National Pipeline Mapping System (NPMS). An operator must provide the NPMS data to the address identified in the NPMS *Operator Standards* manual available at www.npms.phmsa.dot.gov or by contacting the PHMSA geographic information systems manager at (202) 366–4595.

(G) Forms incorporated by reference.

1. The following forms are incorporated by reference and made part of this rule.

A. U.S. Department of Transportation Form PHMSA F 1000.1, revised January 2020. The PHMSA F 1000.1 form is the Operator Identification (OPID) Assignment Request form and does not include any amendments or additions to the January 2020 version.

B. U.S. Department of Transportation Form PHMSA F 1000.2, revised March 2022. The PHMSA F 1000.2 form is the National Registry Notification form for reporting changes including operator name change, change in entity operating, shared safety program change, change in ownership for gas facilities, construction or rehabilitation of gas facilities, change in ownership for LNG, and construction for LNG. The PHMSA F 1000.2 form does not include any amendments or additions to the March 2022 version.

C. U.S. Department of Transportation Form PHMSA F 7100.1, revised May 2021. The PHMSA F 7100.1 form is the incident report form for gas distribution systems and does not include any amendments or additions to the May 2021 version.

D. U.S. Department of Transportation Form PHMSA F 7100.1-1, revised May 2021. The PHMSA F 7100.1-1 form is the annual report form for gas distribution systems and does not include any amendments or additions to the May 2021 version.

E. Reserved.

F. U.S. Department of Transportation Form PHMSA F 7100.2, revised March 2022. The PHMSA F 7100.2 form is the incident report form for gas transmission and gathering pipeline systems and does not include any amendments or additions to the March 2022 version.

G. U.S. Department of Transportation Form PHMSA F 7100.2-1, revised March 2022. The PHMSA F 7100.2-1 form is the annual report form for gas transmission and gathering pipeline systems and does not include any amendments or additions to the March 2022 version.

H. U.S. Department of Transportation Form PHMSA F 7100.3, revised April 2019. The PHMSA F 7100.3 form is the incident report form for LNG facilities and does not include any amendments or additions to the April 2019 version.

I. U.S. Department of Transportation Form PHMSA F 7100.3-1, revised October 2014. The PHMSA F 7100.3-1 form is the annual report form for LNG facilities and does not include any amendments or additions to the October 2014 version.

J. U.S. Department of Transportation Form PHMSA 7100.4-1, approved August 2017. The PHMSA F 7100.4-1 form is the annual report form for underground natural gas storage facilities and does not include any amendments or additions to the August 2017 version.

K. U.S. Department of Transportation Form PHMSA 7100.2.2, approved March 2022. The PHMSA F 7100.2.2 form is the incident report form for reporting-regulated gathering pipeline systems and does not include any amendments or additions to the March 2022 version.

L. U.S. Department of Transportation Form PHMSA 7100.2-3, approved March 2022. The PHMSA F 7100.2-3 form is the annual report form for reporting-regulated gathering pipeline systems and does not include any amendments or additions to the March 2022 version.

2. The forms listed in paragraph (5)(D)1. are published by the U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington, DC 20590-0001. The forms are available at www.phmsa.dot.gov/forms/pipeline-forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E).

(6) Distribution System — Federal Incident Report. (191.9)

(A) Except as provided in subsection (6)(C), each operator of a distribution pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.1 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised May 2021) is incorporated by reference in subsection (5)(G).

(B) When additional relevant information is obtained after the report is submitted under subsection (6)(A), the operator shall make supplementary reports, as deemed necessary, with a clear reference by date and subject to the original report.

(C) The incident report required by this section need not be submitted with respect to master meter systems.

(7) Distribution System — Annual Report.

(A) Annual report. (191.11)

1. Except as provided in paragraph (7)(A)3., each operator of a distribution pipeline system must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.1-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A).

2. The annual report form (revised May 2021) is incorporated by reference in subsection (5)(G).

3. The annual report requirement in this subsection does not apply to a master meter system, a petroleum gas system that serves fewer than one hundred (100) customers from a single source, or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in 20 CSR 4240-40.030(1)(E). (192.8)

(B) Reserved.

(8) Distribution Systems Reporting Transmission Pipelines — Transmission or Gathering Systems Reporting Distribution Pipelines. (191.13) Each operator primarily engaged in gas distribution who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by sections (9) and (10) (191.15 and 191.17). Each operator primarily engaged in gas transmission or gathering who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by sections (6) and (7) (191.9 and 191.11).

(9) Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities — Federal Incident Report. (191.15)

(A) Transmission or gathering.

1. Each operator of a transmission or a regulated onshore gathering pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3). (191.5) See the report submission requirements in subsection (5)(A). The incident report form (revised March 2022) is incorporated by reference in subsection (5)(G).

2. Each operator of a reporting-regulated gathering pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.2.2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5) that occurs after May 16, 2022. See the report submission requirements in subsection (5)(A). The incident report form (revised March 2022) is incorporated by reference in subsection (5)(G).

(B) LNG. Each operator of a liquefied natural gas plant or facility must submit U.S. Department of Transportation Form PHMSA F 7100.3 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised April 2019) is incorporated by reference in subsection (5)(G).

(C) Underground natural gas storage facility. Each operator of an UNGSF must submit U.S. Department of Transportation Form PHMSA F 7100.2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3). (191.5) See the report submission requirements in subsection (5)(A). The incident report form (revised March 2022) is incorporated by reference in subsection (5)(G).

(D) Supplemental report. Where additional related information is obtained after an operator submits a report under subsection (9)(A), (9)(B), or (9)(C), the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report.

(10) Transmission Systems; Gathering Systems; Liquefied Natural Gas Facilities; and Underground Natural Gas Storage Facilities — Annual Report. (191.17)

(A) Transmission or gathering.

1. Each operator of a transmission or a regulated onshore gathering pipeline system must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (revised March 2022) is incorporated by reference in subsection (5)(G).

2. Type R gathering. Beginning with an initial annual report submitted in March 2023 for the 2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.2-3. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (revised March 2022) is incorporated by reference in subsection (5)(G).

(B) LNG. Each operator of a liquefied natural gas facility must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.3-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (revised October 2014) is incorporated by reference in subsection (5)(G).

(C) Underground natural gas storage facility. Each operator of an UNGSF must submit an annual report through U.S. Department of Transportation Form PHMSA 7100.4-1. This report must be submitted each year, no later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (August 2017) is incorporated by reference in subsection (5)(G).

(11) National Registry of Pipeline and LNG Operators. (191.22)

(A) OPID request.

1. Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline, pipeline facility, or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request (U.S. Department of Transportation Form PHMSA F 1000.1) through the National Registry of Operators at https://portal.phmsa.dot.gov unless an alternative reporting method is authorized in accordance with subsection (5)(D). A copy of each submission to PHMSA must also be submitted concurrently to designated commission personnel—see addresses in subsection (5)(E).

2. The OPID Assignment Request form (January 2020) is incorporated by reference in subsection (5)(G).

(B) OPID validation. An operator who has already been assigned one (1) or more OPIDs by January 1, 2011, must validate the information associated with each OPID through the National Registry of Operators at https://portal.phmsa.dot.gov, and correct that information as necessary, no later than September 30, 2012 (PHMSA Advisory Bulletin ADB-2012-04 extended the deadline from June 30, 2012, to September 30, 2012).

(C) Changes. Each operator of a gas pipeline, gas pipeline facility, UNGSF, LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of Operators at https://portal.phmsa.dot.gov of certain events. A copy of each online notification must also be submitted concurrently to designated commission personnel—see addresses in subsection (5)(E).

1. An operator must notify PHMSA of any of the following events not later than sixty (60) days before the event occurs:

A. Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs ten (10) million dollars or more. If sixty- (60-) day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

B. Construction of ten (10) or more miles of a new pipeline;

C. Construction of a new LNG plant, LNG facility, or UNGSF;

D. Maintenance of an UNGSF that involves the plugging or abandonment of a well, or that requires a workover rig and costs two hundred thousand dollars ($200,000) or more for an individual well, including its wellhead. If sixty- (60-) day notice is not feasible due to an emergency, an operator must promptly respond to the emergency and notify PHMSA as soon as practicable;

E. Reversal of product flow direction when the reversal is expected to last more than thirty (30) days. This notification is not required for pipeline systems already designed for bi-directional flow; or

F. A pipeline converted for service under 20 CSR 4240-40.030(1)(H) (192.14), or a change in commodity as reported on the annual report as required by section (10) (191.17).

2. An operator must notify PHMSA of any of the following events not later than sixty (60) days after the event occurs:

A. A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this rule covering pipeline facilities operated under multiple OPIDs;

B. A change in the name of the operator;

C. A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, UNGSF, or LNG facility;

D. The acquisition or divestiture of fifty (50) or more miles of a pipeline or pipeline system subject to 20 CSR 4240-40.030; or

E. The acquisition or divestiture of an existing UNGSF, or an LNG plant, or LNG facility subject to 49 CFR Part 193.

(D) Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under 20 CSR 4240-40.020, 40.030, 40.033, and 40.080, and for submissions to the National Pipeline Mapping System.

(12) Reporting Safety-Related Conditions. (191.23)

(A) Except as provided in subsection (12)(B), each operator must report in accordance with section (13) (191.25) the existence of any of the following safety-related conditions involving facilities in service:

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

2. In the case of an UNGSF, general corrosion that has reduced the wall thickness of any metal component to less than that required for the well's maximum operating pressure, or localized corrosion pitting to a degree where leakage might result;

3. Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of an UNGSF, or an LNG facility that contains, controls, or processes gas or LNG;

4. Any crack or other material defect that impairs the structural integrity or reliability of an UNGSF or an LNG facility that contains, controls, or processes gas or LNG;

5. Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of twenty percent (20%) or more of its specified minimum yield strength or an UNGSF;

6. Any malfunction or operating error that causes the pressure, plus the margin (build-up) allowed for operation of pressure limiting or control devices, to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an UNGSF, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG;

7. A leak in a pipeline, UNGSF, or LNG facility that contains or processes gas or LNG that constitutes an emergency;

8. Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

9. Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a twenty percent (20%) or more reduction in

operating pressure or shutdown of operation of a pipeline, UNGSF, or an LNG facility that contains or processes gas or LNG;

10. For transmission pipelines only, each exceedance of the maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of 20 CSR 4240-40.030(4)(FF) and (13)(R) (192.201 and 192.739). The reporting requirement of this paragraph is not applicable to gathering lines, distribution lines, LNG facilities, or underground natural gas storage facilities (see paragraph (12)(A)6.); and

11. Any malfunction or operating error that causes the pressure of a UNGSF using a salt cavern for natural gas storage to fall below its minimum allowable operating pressure, as defined by the facility's State or Federal operating permit or certificate, whichever pressure is higher.

(B) A report is not required for any safety-related condition that—

1. Exists on a master meter system, a reporting-regulated gathering pipeline, a Type C gas gathering pipeline with an outside diameter of 12.75 inches or less, a Type C gathering pipeline covered by the exception in 49 CFR 192.9(f)(1), or a customer-owned service line;

2. Is an incident or results in an incident before the deadline for filing the safety-related condition report;

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

4. Exists on an UNGSF, where a well or wellhead is isolated, allowing the reservoir or cavern and all other components of the facility to continue to operate normally and without pressure restriction; or

5. Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for—

A. Conditions under paragraph (12)(A)1., unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and

B. Any condition under paragraph (12)(A)10.

(13) Filing Safety-Related Condition Reports. (191.25)

(A) Each report of a safety-related condition under paragraphs (12)(A)1.-9. must be filed (received by the Associate Administrator, Office of Pipeline Safety at PHMSA and designated commission personnel) in writing within five (5) working days (not including Saturday, Sunday, or federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than ten (10) working days after the day a representative of the operator discovers the possibility of a condition. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in subsection (13)(C).

(B) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in paragraph (12)(A)10. for a gas transmission pipeline must be filed (received by the Associate Administrator, Office of Pipeline Safety at PHMSA and designated commission personnel) in writing within five (5) calendar days of the exceedance using the reporting methods and report requirements described in subsection (13)(C).

(C) Reports must be filed by email to InformationResourcesManager@dot.gov or by facsimile to (202) 366–7128 for the Office of Pipeline Safety, and by email to PipelineSafetyProgramManager@psc.mo.gov or by facsimile to (573) 522-1946 for designated commission personnel. For a report made pursuant to paragraphs (12)(A)1.-9., the report must be headed "Safety-Related Condition Report." For a report made pursuant to paragraph (12)(A)10., the report must be headed "Maximum Allowable Operating Pressure Exceedances." All reports must provide the following information:

1. Name, principal address, and operator identification number (OPID) of the operator;

2. Date of report;

3. Name, job title, and business telephone number of the person submitting the report;

4. Name, job title, and business telephone number of the person who determined that the condition exists;

5. Date the condition was discovered and date the condition was first determined to exist;

6. Location of the condition, with reference to the state (and town, city, or county), and as appropriate, nearest street address, survey station number, milepost, landmark, or name of pipeline;

7. Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored; and

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

(14) National Pipeline Mapping System (NPMS). (191.29)

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

1. Geospatial data, attributes, metadata, and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS *Operator Standards Manual* available at www.npms.phmsa.dot.gov or by contacting the PHMSA geographic information systems manager at (202) 366-4595;

2. The name of and address for the operator; and

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

(B) The information required in subsection (14)(A) must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS *Operator Standards* manual available at www.npms.phmsa.dot.gov or contact the PHMSA geographic information systems manager at (202) 366-4595.

(C) This section does not apply to gathering pipelines.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.020. Original rule filed Feb. 5, 1970, effective Feb. 26, 1970. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed Feb. 8, 1985, effective Aug. 11, 1985. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Dec. 14, 2000, effective May 30, 2001. Amended: Filed Oct.*

15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May 30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019. Moved to 20 CSR 4240-40.020, effective Aug. 28, 2019. Amended: Filed Dec. 12, 2019, effective July 30, 2020. Amended: Filed June 29, 2021, effective Jan. 30, 2022. Amended: Filed July 29, 2022, effective Feb. 28, 2023.

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

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

PURPOSE: This rule prescribes minimum safety standards regarding the design, fabrication, installation, construction, metering, corrosion control, testing, uprating, operation, maintenance, leak detection, repair, replacement, and integrity management of pipelines used for the transportation of natural and other gas.

PUBLISHER'S NOTE: The secretary of state has determined that publication of the entire text of the material that is incorporated by reference as a portion of this rule would be unduly cumbersome or expensive. This material as incorporated by reference in this rule shall be maintained by the agency at its headquarters and shall be made available to the public for inspection and copying at no more than the actual cost of reproduction. This note applies only to the reference material. The entire text of the rule is printed here.

*AGENCY NOTE: This rule is similar to the Minimum Federal Safety Standards contained in 49 CFR part 192, **Code of Federal Regulations**. Parallel citations to Part 192 are provided for gas operator convenience and to promote public safety. Appendix E, contained in this rule, is a Table of Contents for 20 CSR 4240-40.030.*

(1) General.

(A) What Is the Scope of this Rule? (192.1)

1. This rule prescribes minimum safety requirements for pipeline facilities and the transportation of gas in Missouri and under the jurisdiction of the commission. A table of contents is provided in Appendix E, which is included herein (at the end of this rule).

2. This rule does not apply to—

A. The gathering of gas—

(I) Through a pipeline that operates at less than zero (0) pounds per square inch gauge (psig) (0 kPa); or

(II) Through a pipeline that is not a regulated onshore gathering line (as determined in (1)(E)); or

B. Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—

(I) Fewer than ten (10) customers, if no portion of the system is located in a public place; or

(II) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

(B) Definitions. (192.3) As used in this rule—

1. Abandoned means permanently removed from service;

2. Active corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety;

3. Administrator means the Administrator of the Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation to whom authority in the matters of pipeline safety have been delegated by the Secretary of the United States Department of Transportation, or his or her delegate;

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

5. Building means any structure that is regularly or periodically occupied by people;

6. Close interval survey means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey;

7. Commission means the Missouri Public Service Commission;

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

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

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

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

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

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

A. At a metering location;

B. A pressure reduction location; or

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

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

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

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

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

pipeline segment maximum allowable operating pressure;

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

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

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

21. Fuel line means the customer-owned gas piping downstream from the outlet of the customer meter or operator-owned pipeline, whichever is farther downstream;

22. Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;

23. Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main;

24. Hard spot means an area on steel pipe material with a minimum dimension greater than two inches (2") (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV_{10});

25. High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than an equivalent to fourteen inches (14") water column;

26. Hoop stress means the stress in a pipe wall acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe produced by the pressure in the pipe;

27. In-line inspection (ILI) means an inspection of a pipeline from the interior of the pipe using an inspection tool also called intelligent or smart pigging. This definition includes tethered and self-propelled inspection tools;

28. In-line inspection tool or instrumented internal inspection device means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an intelligent or smart pig;

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

30. Low-pressure distribution system means a distribution system in which the gas pressure in the main is less than or equal to an equivalent of fourteen inches (14") water column;

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

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

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;

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;

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. This definition does not apply to any gathering line;

37. Operator means a person who engages in the transportation of gas;

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;

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);

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

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

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;

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;

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;

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. This definition does not apply to any gathering line;

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;

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;

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));

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;

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

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

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

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

C. Transports gas within a storage field; or

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

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

54. Tunnel means a subsurface passageway large enough for a man to enter;

55. Vault or manhole means a subsurface structure that a man can enter;

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;

57. Welder means a person who performs manual or semi-automatic welding;

58. Welding operator means a person who operates machine or automatic welding equipment;

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 or more ripples with—

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

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

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

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

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

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

60. 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.

(C) Class Locations. (192.5)

1. This subsection classifies pipeline locations for the purpose of this rule. The following criteria apply to classifications under this section:

A. A "class location unit" is an area that extends two hundred twenty (220) yards (200 meters) on either side of the centerline of any continuous one- (1-) mile (1.6 kilometers) length of pipeline; and

B. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

2. Except as provided in paragraph (1)(C)3., pipeline locations are classified as follows:

A. A Class 1 location is any class location unit that has ten (10) or fewer buildings intended for human occupancy;

B. A Class 2 location is any class location unit that has more than ten (10) but fewer than forty-six (46) buildings intended for human occupancy;

C. A Class 3 location is—

(I) Any class location unit that has forty-six (46) or more buildings intended for human occupancy; or

(II) An area where the pipeline lies within one hundred (100) yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 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); and

D. A Class 4 location is any class location unit where buildings with four (4) or more stories aboveground are prevalent.

3. The length of Class locations 2, 3, and 4 may be adjusted as follows:

A. A Class 4 location ends two hundred twenty (220) yards (200 meters) from the nearest building with four (4) or more stories aboveground; and

B. When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends two hundred twenty (220) yards (200 meters) from the nearest building in the cluster.

4. An operator must have records that document the current class location of each gas transmission pipeline segment and that demonstrate how the operator determined each current class location in accordance with this subsection.

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

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2021, and the subsequent amendment 192-132 (published in *Federal Register* on August 24, 2022, page 87 FR 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, 2021, version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. 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.

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

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

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

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

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

(E) Gathering Lines.

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

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

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

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

(III) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than fifty (50) miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR 190.9).

(IV) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

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

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

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

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

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

(b) Justification for an alternative compliance deadline; and

(c) Proposed alternative deadline.

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

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

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

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

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

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

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

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

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

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

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

B. Type A lines. An operator of a Type A regulated gathering line must comply with the requirements of this rule applicable to transmission lines, except the requirements in

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

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

(I) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this rule applicable to transmission lines. Compliance with (2)(G), (3)(M), (4)(U)4. and 5., (4)(II), (5)(D)3., (6)(H)5., (7)(J)3.–6., (10)(K), (12)(X), and (12)(Z) is not required;

(II) If the pipeline is metallic, control corrosion according to requirements of section (9) applicable to transmission lines, except the requirements in (9)(G)6.–9., (9)(I)4. and 6., (9)(M)3., (9)(S)3., (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 the requirements of subsection (12)(J), effective February 28, 2023;

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

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

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

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

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

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

E. Exceptions.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(a) May 16, 2023; or

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(F) Petroleum Gas Systems. (192.11)

1. Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this rule and of NFPA 58 and NFPA 59 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

2. Each pipeline system subject to this rule that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this rule and of NFPA 58 and NFPA 59 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

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

(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.

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.

(H) Conversion to Service Subject to this Rule. (192.14)

1. Except as provided in paragraph (1)(H)4., a pipeline previously used in service not subject to this rule qualifies for use under this rule if the operator prepares and follows a written procedure to carry out the following requirements:

A. The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation;

B. The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline;

C. All known unsafe defects and conditions must be corrected in accordance with this rule; and

D. The pipeline must be tested in accordance with section (10) to substantiate the maximum allowable operating pressure permitted by section (12).

2. Each operator must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (1)(H)1.

3. An operator converting a pipeline from service not previously covered by this rule must notify PHMSA and designated commission personnel sixty (60) days before the conversion occurs as required by 20 CSR 4240-40.020(11).

4. This paragraph lists situations where steel pipe may not be converted to service subject to this rule.

A. Steel yard lines that are not cathodically protected must be replaced under subsection (15)(C).

B. Buried steel fuel lines that are not cathodically protected may not be converted to a pipeline as defined in subsection (1)(B), such as a service line or main.

C. Buried steel pipes that are not cathodically protected may not be converted to a service line.

D. Buried steel pipes that are not cathodically protected may not be converted to a main in Class 3 and Class 4 locations.

(I) Rules of Regulatory Construction. (192.15)

1. As used in this rule —

A. Includes means including, but not limited to;

B. May means is permitted to or is authorized to;

C. May not means is not permitted to or is not authorized to; and

D. Shall is used in the mandatory and imperative sense.

2. In this rule —

A. Words importing the singular include the plural;

B. Words importing the plural include the singular; and

C. Words importing the masculine gender include the feminine.

(J) Filing of Required Plans, Procedures, and Programs.

1. Each operator shall submit to designated commission personnel all plans, procedures, and programs required by this rule (to include welding and joining procedures, construction standards, control room management procedures, corrosion control procedures, damage prevention program, distribution integrity management plan, emergency procedures, public education program, operator qualification program, replacement programs, transmission integrity management program, and procedural manual for operations, maintenance,

and emergencies). In addition, each change must be submitted to designated commission personnel within twenty (20) days after the change is made.

2. All operators under the pipeline safety jurisdiction of the Missouri Public Service Commission must establish and submit welding procedures, joining procedures, and construction specifications and standards to designated commission personnel before construction activities begin. All other plans, procedures and programs required by rules 20 CSR 4240-40.020, 20 CSR 4240-40.030, and 20 CSR 4240-40.080 must be established and submitted to designated commission personnel before the system is put into operation.

3. A written plan for drug and alcohol testing in accordance with 20 CSR 4240-40.080 must be submitted to designated commission personnel.

(K) Customer Notification Required by Section 192.16 of 49 CFR part 192. (192.16)

1. This subsection applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this subsection, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to subsection (9)(I) if the customer's buried piping is metallic, survey for leaks according to subsection (13)(M), and if an unsafe condition is found, take action according to paragraph (12)(S)3.

2. Each operator shall notify each customer once in writing of the following information:

A. The operator does not maintain the customer's buried piping;

B. If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;

C. Buried gas piping should be—

(I) Periodically inspected for leaks;

(II) Periodically inspected for corrosion if the piping is metallic; and

(III) Repaired if any unsafe condition is discovered;

D. When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand; and

E. The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.

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

4. Each operator must make the following records available for inspection by designated commission personnel:

A. A copy of the notice currently in use; and

B. Evidence that notices have been sent to customers within the previous three (3) years.

(L) Customer Notification, Paragraph (12)(S)2. When providing gas service to a new customer or a customer relocated from a different operating district, see paragraph (12)(S)2. regarding applicable customer notification.

(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 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., (12)(E)5.E., (12)(M)3.B., (12)(U)3.B.(III), (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), (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)), a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (e.g., "other technology" or "alternative equivalent technology") than otherwise prescribed in those requirements, that notification must be submitted to PHMSA for review at least ninety (90) days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique ninety-one (91) days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time to conduct its review.

(2) Materials.

(A) Scope. (192.51) This section prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

(B) General. (192.53) Materials for pipe and components must be—

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

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

3. Qualified in accordance with the applicable requirements of this section;

4. Only of steel or polyethylene for pipe for the underground construction of pipelines, except that other previously qualified materials may be used for repair of pipe constructed of the same material; and

5. Other piping materials may be used with approval of the commission.

(C) Steel Pipe. (192.55)

1. New steel pipe is qualified for use under this rule if—

A. It was manufactured in accordance with a listed specification;

B. It meets the requirements of—

(I) Subsection II of Appendix B to this rule; or

(II) If it was manufactured before November 12, 1970, either subsection II or III of Appendix B to this rule; or

C. It is used in accordance with paragraph (2)(C)3. or 4.

2. Used steel pipe is qualified for use under this rule if—

A. It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of Appendix B to this rule;

B. It meets the requirements of—

(I) Subsection II of Appendix B to this rule; or

(II) If it was manufactured before November 12, 1970, either subsection II or III of Appendix B to this rule;

C. It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B to this rule; or

D. It is used in accordance with paragraph (2)(C)3.

3. New or used steel pipe may be used at a pressure resulting in a hoop stress of less than six thousand (6000) pounds per square inch (psi) (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates that the pipe is in good condition and that it is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of Appendix B to this rule.

4. Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

5. New steel pipe that has been cold expanded must comply with the mandatory provisions of API Specification 5L (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

(D) Plastic Pipe. (192.59)

1. New polyethylene pipe is qualified for use under this rule if—

A. It is manufactured in accordance with a listed specification;

B. It is resistant to chemicals with which contact may be anticipated; and

C. It is free of visual defects.

2. Used plastic pipe is qualified for use under this rule if—

A. It was manufactured in accordance with a listed specification;

B. It is resistant to chemicals with which contact may be anticipated;

C. It has been used only in gas service;

D. Its dimensions are still within the tolerances of the specification to which it was manufactured; and

E. It is free of visible defects.

3. For the purpose of subparagraphs (2)(D)1.A. and 2.A., where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it—

A. Meets the strength and design criteria required of pipe included in that listed specification; and

B. Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

4. Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this rule.

(E) Marking of Materials. (192.63)

1. Except as provided in paragraphs (2)(E)4. and (2)(E)5., each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured.

2. Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

3. If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

4. Paragraph (2)(E)1. does not apply to items manufactured before November 12, 1970, that meet all of the following:

A. The item is identifiable as to type, manufacturer, and model; and

B. Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

5. All plastic pipe and components must also meet the following requirements:

A. All markings on plastic pipe prescribed in the listed specification and the requirements of subparagraph (2)(E)5.B. must be repeated at intervals not exceeding two (2) feet;

B. Plastic pipe and components manufactured after December 31, 2019 must be marked in accordance with the listed specification; and

C. All physical markings on plastic pipelines prescribed in the listed specification and subparagraph (2)(E)5.B. must be legible until the time of installation.

(F) Transportation of Pipe. (192.65)

1. Railroad. In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by railroad unless the transportation is performed in accordance with API RP 5L1 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

2. Ship or barge. In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. Truck. In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

(G) Records: Material Properties. (192.67)

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

2. For steel transmission pipelines installed on or before July 1, 2020, if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with subsections (2)(B) and (2)(C) (192.53 and 192.55), operators must retain such records for the life of the pipeline.

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

(U) (192.624) according to the terms of that subsection.

(H) Storage and Handling of Plastic Pipe and Associated Components. (192.69) Each operator must have and follow written procedures for the storage and handling of plastic pipe and associated components that meet the applicable listed specifications.

(3) Pipe Design.

(A) Scope. (192.101) This section prescribes the minimum requirements for the design of pipe.

(B) General. (192.103) Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

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

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

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

where—

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

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

D = Nominal outside diameter of the pipe in inches (millimeters);

t = Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with subsection (3)(E) (192.109). Additional wall thickness required for concurrent external loads in accordance with subsection (3)(B) (192.103) may not be included in computing design pressure;

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

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

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

2. If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to seventy-five percent (75%) of the pressure determined under paragraph (3)(C)1. if the temperature of the pipe exceeds 900 °F (482 °C) at any time or is held above 600 °F (316 °C) for more than one (1) hour.

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

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

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

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

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

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

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

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

1. If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

2. However, if the pipe is of uniform grade, size, and thickness and there are more than ten (10) lengths, only ten percent (10%) of the individual lengths, but not less than ten (10) lengths, need to be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in subsection (3)(C) (192.105) is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than one and fourteen hundredths (1.14) times the smallest measurement taken on pipe less than twenty inches (20”) (508 millimeters) in outside diameter, nor more than one and eleven hundredths (1.11) times the smallest measurement taken on pipe twenty inches (20”) (508 millimeters) or more in outside diameter.

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

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

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

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

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

B. Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;

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

D. Is used in a fabricated assembly (including separators, mainline valve assemblies, cross-connections and river crossing headers) or is used within five (5) pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

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

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

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

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

(G) Longitudinal Joint Factor (E) for Steel Pipe. (192.113) The longitudinal joint factor to be used in the design formula in subsection (3)(C) is determined in accordance with the following table:

Specification	Pipe Class	Longitudinal Joint Factor (E)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.60
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric fusion welded	1.00
ASTM A 672	Electric fusion welded	1.00
ASTM A 691	Electric fusion welded	1.00
API 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	0.60
Other	Pipe over 4 inches (102 millimeters)	0.80
Other	Pipe 4 inches (102 millimeters) or less	0.60

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

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

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

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

(I) Design of Plastic Pipe. (192.121)

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

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

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

where

P = Design pressure, psi (kPa) gauge;

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

t = Specified wall thickness, inches (millimeters);

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

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

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

2. General Requirements for Plastic Pipe and Components.

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

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

(I) Below -20 °F (-29 °C), or -40 °F (-40 °C) if all pipe and pipeline components whose operating temperature will be below -20 °F (-29 °C) have a temperature rating by the manufacturer consistent with that operating temperature; or

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

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

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

3. Polyethylene (PE) Pipe Requirements.

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

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

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

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

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

(IV) The wall thickness for a given outside diameter is not less than that listed in the following table:

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

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

(J) *Reserved*. (192.123)

(K) Design of Copper Pipe for Repairs. (192.125)

1. Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.

2. Copper pipe used in service lines must have a minimum wall thickness not less than that indicated in the following table:

Standard Size (inch) (millimeter)	Nominal O.D. (inch) (millimeters)	Wall Thickness Nominal	Tolerance (inch) (millimeter)
1/2 (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
5/8 (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
3/4 (19)	.875 (22)	.045 (1.14)	.004 (.102)
1 (25)	1.125 (29)	.050 (1.27)	.004 (.102)
1 1/4 (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
1 1/2 (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

3. Copper pipe used in mains and services lines may not be used at pressures in excess of 100 psi (689 kPa) gauge.

4. Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft^3 (6.9/m^3) under standard conditions. Standard conditions refers to 60 °F and 14.7 psia (38 °C and one atmosphere) of gas.

(L) Additional Design Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.112) The federal regulations at 49 CFR 192.112 are not adopted in this rule.

(M) Records: Pipe Design. (192.127)

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

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

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

(4) Design of Pipeline Components.

(A) Scope. (192.141) This section prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

(B) General Requirements. (192.143)

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

2. The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in section (9).

3. Except for excess flow valves, each plastic pipeline component installed after April 22, 2019, must be able to withstand operating pressures and other anticipated loads in accordance with a listed specification.

(C) Qualifying Metallic Components. (192.144) Notwithstanding any requirement of this section which incorporates by reference an edition of a document listed in 49 CFR 192.7 (see (1)(D)) or Appendix B, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this rule if—

1. It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and

2. The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in 49 CFR 192.7 (see (1)(D)) or Appendix B:

A. Pressure testing;

B. Materials; and

C. Pressure and temperature ratings.

(D) Valves. (192.145)

1. Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Specification 6D (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

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

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

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

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

(II) After the shell test, the seat must be tested to a pressure not less than one and one-half (1.5) times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted; and

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

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

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

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

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

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

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

(E) Flanges and Flange Accessories. (192.147)

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

2. Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

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

(F) Standard Fittings. (192.149)

1. The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this rule or their equivalent.

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

3. Plastic fittings installed after April 22, 2019, must meet a listed specification.

(G) Tapping. (192.151)

1. Each mechanical fitting used to make a hot tap must be designed for at least the operating pressure of the pipeline.

2. Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

3. Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than twenty-five percent (25%) of the nominal diameter of the pipe unless the pipe is reinforced, except that—

A. Existing taps may be used for replacement service, if they are free of cracks and have good threads; and

B. A one and one-fourth inch (1 1/4") (32 millimeters) tap may be made in a four-inch (4") (102 millimeters) cast iron or ductile iron pipe, without reinforcement.

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

(H) Components Fabricated by Welding. (192.153)

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

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

A. Regularly manufactured butt-welding fittings;

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

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

D. Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

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

4. Except for flat closures designed in accordance with the *ASME Boiler and Pressure Vessel Code* (Section VIII, Division 1 or 2) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), flat closures and fish tails may not be used on pipe that either operates at 100 psi (689 kPa) gauge or more,

or is more than three inches (3") (76 millimeters) nominal diameter.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(J) Extruded Outlets. (192.157) Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

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

(L) Supports and Anchors. (192.161)

1. Each pipeline and its associated equipment must have enough anchors or supports to—

A. Prevent undue strain on connected equipment;

B. Resist longitudinal forces caused by a bend or offset in the pipe; and

C. Prevent or damp out excessive vibration.

2. Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

3. Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

A. Free expansion and contraction of the pipeline between supports or anchors may not be restricted;

B. Provision must be made for the service conditions involved; and

C. Movement of the pipeline may not cause disengagement of the support equipment.

4. Each support on an exposed pipeline operated at a stress level of fifty percent (50%) or more of SMYS must comply with the following:

A. A structural support may not be welded directly to the pipe;

B. The support must be provided by a member that completely encircles the pipe; and

C. If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

5. Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement or it must have an anchor that will limit the movement of the pipeline.

6. Each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

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

1. Location of compressor building. Except for a compressor building on a platform located in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property not under control of the operator to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of firefighting equipment.

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

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

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

3. Exits. Each operating floor of a main compressor building must have at least two (2) separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to a place of safety. Each door latch on an exit must be of a type which can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

4. Fenced areas. Each fence around a compressor station must have at least two (2) gates located so as to provide a convenient opportunity for escape to a place of safety or have other facilities affording a similarly convenient exit from the area. Each gate located within two hundred feet (200') (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

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

(N) Compressor Stations — Liquid Removal. (192.165)

1. Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of liquids in quantities that could cause damage.

2. Each liquid separator used to remove entrained liquids at a compressor station must —

A. Have a manually operable means of removing these liquids;

B. Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and

C. Be manufactured in accordance with section VIII of the *ASME Boiler and Pressure Vessel Code* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) and the additional requirements of paragraph (4)(H)5., except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4 or less.

(O) Compressor Stations — Emergency Shutdown. (192.167)

1. Except for unattended field compressor stations of one thousand (1,000) horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:

A. It must be able to block gas out of the station and blowdown the station piping;

B. It must discharge gas from the blowdown piping at a location where the gas will not create a hazard;

C. It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except that —

(I) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

(II) Electrical circuits needed to protect equipment from damage may remain energized; and

D. It must be operable from at least two (2) locations, each of which is —

(I) Outside the gas area of the station;

(II) Near the exit gates if the station is fenced or near emergency exits if not fenced; and

(III) Not more than five hundred feet (500') (153 meters) from the limits of the station.

2. If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

3. On a platform located in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

A. In the case of an unattended compressor station —

(I) When the gas pressure equals the maximum allowable operating pressure plus fifteen percent (15%); or

(II) When an uncontrolled fire occurs on the platform; and

B. In the case of a compressor station in a building —

(I) When an uncontrolled fire occurs in the building; or

(II) When the concentration of gas in air reaches fifty percent (50%) or more of the lower explosive limit in a building which has a source of ignition. For the purpose of part (4)(O)3.B.(II), an electrical facility which conforms to Class 1, Group D of the *National Electrical Code* is not a source of ignition.

(P) Compressor Stations—Pressure Limiting Devices. (192.169)

1. Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than ten percent (10%).

2. Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

(Q) Compressor Stations—Additional Safety Equipment. (192.171)

1. Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

2. Each compressor station prime mover other than an electrical induction or synchronous motor must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

3. Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

4. Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

5. Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

(R) Compressor Stations—Ventilation. (192.173) Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

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

1. Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe or in auxiliary equipment that might cause corrosion or interfere with the safe operation of the holder.

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

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

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

where

C = Minimum clearance between pipe containers or bottles in inches (millimeters);

D = Outside diameter of pipe containers or bottles in inches (millimeters);

P = Maximum allowable operating pressure, psi (kPa) gauge; and

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

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

1. Each bottle-type holder must be—

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

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

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

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

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

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

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

C. Welding may not be performed on the holder after it has been heat-treated or stress-relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized Thermit welding process is used;

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

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

(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 subsection (12)(Z). The installation requirements in this paragraph do not apply to pipe segments with 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') in either Class 1 or Class 2 locations. 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 subsection (12)(Z). The requirements of this paragraph apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. The installation requirements in this paragraph do not apply to pipe segments with 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') in either Class 1 or Class 2 locations. 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.

(V) Distribution Line Valves. (192.181)

1. Each high pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains and the local physical conditions, but it must at least provide zones of isolation sized so that the operator could relight the lost customer services within a period of eight (8) hours after restoration of system pressure.

2. Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping and on the outlet piping at a sufficient distance from the regulator station to permit the operation of the valve during an emergency that might preclude access to the station. An outlet valve on regulator stations will not be required on single-feed distribution systems when the outlet piping size is less than or equal to two inches (2") in nominal diameter.

3. Each valve on a main installed for operating or emergency purposes must comply with the following:

A. The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency;

B. The operating stem or mechanism must be readily accessible; and

C. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

(W) Vaults—Structural Design Requirements. (192.183)

1. Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations must be able to meet the loads which may be imposed upon it and to protect installed equipment.

2. There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

3. Each pipe entering, or within, a regulator vault or pit must be steel for sizes ten inches (10") (254 millimeters), and less, except that control and gauge piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.

(X) Vaults—Accessibility. (192.185) Each vault must be located in an accessible location and, so far as practical, away from—

1. Street intersections or points where traffic is heavy or dense;

2. Points of minimum elevation, catch basins or places where the access cover will be in the course of surface waters; and

3. Water, electric, steam, or other facilities.

(Y) Vaults—Sealing, Venting, and Ventilation. (192.187) Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented, or ventilated, as follows:

1. When the internal volume exceeds two hundred (200) cubic feet (5.7 cubic meters)—

A. The vault or pit must be ventilated with two (2) ducts, each having at least the ventilating effect of a pipe four inches (4") (102 millimeters) in diameter;

B. The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

C. The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged;

2. When the internal volume is more than seventy-five (75) cubic feet (2.1 cubic meters) but less than two hundred (200)

cubic feet (5.7 cubic meters)—

A. If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;

B. If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or

C. If the vault or pit is ventilated, paragraph (4)(Y)1. or 3. applies; and

3. If a vault or pit covered by paragraph (4)(Y)2. is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than twenty to one (20:1), no additional ventilation is required.

(Z) Vaults—Drainage and Waterproofing. (192.189)

1. Each vault must be designed so as to minimize the entrance of water.

2. A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

3. All electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the *National Electrical Code*, NFPA-70 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

(AA) Risers Installed After January 22, 2019. (192.204)

1. Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.

2. Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973–13 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this paragraph must have a rigid riser casing.

(BB) Valve Installation in Plastic Pipe. (192.193) Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

(CC) Protection Against Accidental Overpressuring. (192.195)

1. General requirements. Except as provided in subsection (4)(DD) (192.197), each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded, as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of subsections (4)(EE) and (FF). (192.199 and 192.201)

2. Additional requirements for distributions systems. Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

A. Have pressure regulation devices capable of meeting the pressure, load and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

B. Be designed so as to prevent accidental overpressuring.

(DD) Control of the Pressure of Gas Delivered from Transmission Lines and High-Pressure Distribution Systems to Service Equipment. (192.197) If the maximum allowable operating pressure of the system exceeds fourteen inches (14") water column, one (1) of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

1. A service regulator with a suitable over-pressure protection device set to limit, to a maximum safe value, the pressure of the gas delivered to the customer and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than sixty (60) psi (414 kPa) gauge. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to sixty (60) psi (414 kPa) gauge or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts and remains closed until manually reset, if the pressure on the inlet of the service regulator exceeds the set pressure (sixty (60) psi (414 kPa) gauge or less);

2. A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer. A device or method that indicates the failure of the service regulator must also be provided. The service regulator must be monitored at intervals not exceeding fifteen (15) months, but at least once each calendar year for detection of a failure;

3. A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds sixty (60) psi (414 kPa) gauge. For higher inlet pressure, the methods in paragraph (4)(DD)1. or 2. must be used; or

4. A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

(EE) Requirements for Design of Pressure Relief and Limiting Devices. (192.199) Except for rupture discs, each pressure relief or pressure limiting device must—

1. Be constructed of materials so that the operation of the device will not be impaired by corrosion;

2. Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

3. Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate and can be tested for leakage when in the closed position;

4. Have support made of noncombustible material;

5. Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;

6. Be designed and installed so that the size of the openings, pipe and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

7. Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident, for instance, an explosion in a vault or damage by a vehicle, from affecting the operation of both the overpressure protective device and the district regulator;

8. Except for a valve that will isolate the system under

protection from its source of pressure, be designed to prevent unauthorized access to or operation of the following stop valves regardless of installation date:

A. Any valve that will make the pressure relief valve or pressure limiting device inoperative;

B. Valves that would bypass the regulator or relief devices; and

C. Shut-off valves in control lines that, if operated, would cause the regulator or overpressure protection device to be inoperative;

9. Be designed and installed so that adequate overpressure protection is provided for all town border stations and district regulator stations regardless of installation date;

10. Where a monitor regulator is used for overpressure protection, be designed and installed to include an internal or separate device or method that indicates a failure of the operating regulator regardless of installation date. The operating regulator must be monitored at least monthly for regulator stations for detection of a failure; and

11. Where regulators in series or working monitors are used for overpressure protection, be designed and installed to include an internal or separate device or method that indicates a failure of each regulator regardless of installation date. Each regulator must be monitored at least monthly for regulator stations for detection of a failure. When the operator chooses to use a pressure gauge as the separate device to comply with paragraph (4)(EE)10. or 11., the pressure gauge must have the capability to record the high pressure, such as a recording chart or "tattle-tale" needle (a standard sight gauge is not adequate for this purpose).

(FF) Required Capacity of Pressure Relieving and Limiting Stations. (192.201)

1. Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to ensure the following:

A. In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment; and

B. In pipelines other than a low pressure distribution system—

(I) If the maximum allowable operating pressure is sixty (60) psi (414 kPa) gauge or more, the pressure may not exceed the maximum allowable operating pressure plus ten percent (10%) or the pressure that produces a hoop stress of seventy-five percent (75%) of SMYS, whichever is lower;

(II) If the maximum allowable operating pressure is twelve (12) psi (83 kPa) gauge or more, but less than sixty (60) psi (414 kPa) gauge, the pressure may not exceed the maximum allowable operating pressure plus six (6) psi (41 kPa) gauge; or

(III) If the maximum allowable operating pressure is less than twelve (12) psi (83 kPa) gauge, the pressure may not exceed the maximum allowable operating pressure plus fifty percent (50%).

2. When more than one (1) pressure regulating or compressor station feeds into a pipeline, relief valves or other protective devices must be installed at each station to ensure that the complete failure of the largest capacity regulator or compressor, or any single run of lesser capacity regulators or compressors in that station, will not impose pressures on any part of the pipeline or distribution system in excess of those for which it was designed, or against which it was protected, whichever is lower.

3. Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

(GG) Instrument, Control, and Sampling Pipe and Components. (192.203)

1. Applicability. This subsection applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.

2. Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:

A. Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue;

B. Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary;

C. Brass or copper material may not be used for metal temperatures greater than four hundred degrees Fahrenheit (400 °F) (204 °C);

D. Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing;

E. Pipe or components in which liquids may accumulate must have drains or drips;

F. Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning;

G. The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses;

H. Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip-type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself; and

I. Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one (1) control line from making both the regulator and the overpressure protective device inoperative.

(HH) Passage of Internal Inspection Devices. (192.150)

1. Except as provided in paragraphs (4)(HH)2. and (4)(HH)3., each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

2. This subsection does not apply to—

A. Manifolds;

B. Station piping such as at compressor stations, meter stations, or regulator stations;

C. Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

D. Cross-overs;

E. Sizes of pipe for which an instrumented internal inspection device is not commercially available;

F. Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;

G. Gathering lines; and

H. Other piping that, under 49 CFR 190.9, the administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

3. An operator encountering emergencies, construction time constraints, or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (4)(HH)1., if the operator determines and documents why an impracticability prohibits compliance with paragraph (4)(HH)1. Within thirty (30) days of discovering the emergency or construction problem, the operator must petition, under 49 CFR 190.9, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within one (1) year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

(II) Records: Pipeline Components. (192.205)

1. For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested in accordance with this section. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of forty-two thousand (42,000) psi (X42) or greater and with nominal diameters of greater than two inches (2") must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.

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

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

(5) Welding of Steel in Pipelines.

(A) Scope. (192.221)

1. This section prescribes minimum requirements for welding steel materials in pipelines.

2. This section does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

(B) General.

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

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

(C) Welding Procedures. (192.225)

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

2. Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

(D) Qualification of Welders and Welding Operators. (192.227)

1. Except as provided in paragraph (5)(D)2., each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A, or Appendix B of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) or section IX of the ASME Boiler and Pressure Vessel Code (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). However, a welder or welding operator qualified under an earlier edition of a standard listed in 49 CFR 192.7 (see subsection (1)(D)) may weld but may not requalify under that earlier edition.

2. A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than twenty percent (20%) of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in subsection I. of Appendix C, which is included herein (at the end of this rule). Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under subsection II. of Appendix C as a requirement of the qualifying test.

3. For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of five (5) years following construction.

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

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

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

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

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

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

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

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

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

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

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

(F) Protection From Weather. (192.231) The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

(G) Miter Joints. (192.233)

1. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of thirty percent (30%) or more of SMYS may not deflect the pipe more than three degrees (3°).

2. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than thirty percent (30%), but more than ten percent (10%), of SMYS may not deflect the pipe more than twelve and one-half degrees (12 1/2°) and must be a distance equal to one (1) pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

3. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of ten percent (10%) or less of SMYS may not deflect the pipe more than ninety degrees (90°).

(H) Preparation for Welding. (192.235) Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

(I) Inspection and Test of Welds. (192.241)

1. Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that—

A. The welding is performed in accordance with the welding procedure; and

B. The weld is acceptable under paragraph (5)(I)3.

2. The welds on a pipeline to be operated at a pressure that produces a hoop stress of twenty percent (20%) or more of SMYS must be nondestructively tested in accordance with subsection (5)(J), except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if—

A. The pipe has a nominal diameter of less than six inches (6") (152 millimeters); or

B. The pipeline is to be operated at a pressure that produces a hoop stress of less than forty percent (40%) of SMYS and the welds are so limited in number that nondestructive testing is impractical.

3. The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 or Appendix A of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). Appendix A of API Standard 1104 may not be used to accept cracks.

(J) Nondestructive Testing. (192.243)

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

2. Nondestructive testing of welds must be performed—

A. In accordance with written procedures; and

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

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

4. When nondestructive testing is required under paragraph (5)(I)2. (192.241[b]), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

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

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

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

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

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

6. When nondestructive testing is required under paragraph (5)(I)2. (192.241[b]), each operator must retain, for the life of the pipeline, a record showing, by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected and the disposition of the rejects.

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

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

2. Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

3. Repair of a crack or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under subsection (5)(C) (192.225). Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

(6) Joining of Materials Other Than by Welding.

(A) Scope. (192.271)

1. This section prescribes minimum requirements for joining materials in pipelines, other than by welding.

2. This section does not apply to joining during the manufacture of pipe or pipeline components.

(B) General. (192.273)

1. The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

2. Each joint must be made in accordance with written procedures that have been proved by test or experience to produce strong gastight joints.

3. Each joint must be inspected to ensure compliance with this section.

(C) Cast Iron Pipe. (192.275)

1. Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

2. Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

3. Cast iron pipe may not be joined by threaded joints.

4. Cast iron pipe may not be joined by brazing.

(D) Ductile Iron Pipe. (192.277)

1. Ductile iron pipe may not be joined by threaded joints.

2. Ductile iron pipe may not be joined by brazing.

(E) Copper Pipe. (192.279) Copper pipe may not be threaded, except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

(F) Plastic Pipe (192.281)

1. General. A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

2. Solvent cement joints. Each solvent cement joint on plastic pipe must comply with the following:

A. The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint;

B. The solvent cement must conform to ASTM D 2564-12 for PVC (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)); and

C. The joint may not be heated or cooled to accelerate the setting of the cement.

3. Heat-fusion joints. Each heat-fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints, and the following:

A. A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under subsection (6)(G);

B. A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component uniformly and simultaneously to establish the same temperature. The device used must be the same device specified in the operator's joining procedure for socket fusion;

C. An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer or using equipment and techniques shown, by testing joints to the requirements of part (6)(G)1.A.(III), to be equivalent or better than the requirements of the fitting manufacturer; and

D. Heat may not be applied with a torch or other open flame.

4. Mechanical joints. Each compression type mechanical joint on plastic pipe must comply with the following:

A. The gasket material in the coupling must be compatible with the plastic;

B. A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling;

C. All mechanical fittings must meet a listed specification based upon the applicable material; and

D. All mechanical joints or fittings installed after April 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than twenty-five percent (25%) elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

(G) Plastic Pipe — Qualifying Joining Procedures. (192.283)

1. Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under paragraph (6)(B)2. is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests, as applicable:

A. The test requirements of —

(I) In the case of thermoplastic pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification;

(II) *(Reserved)*;

(III) In the case of electrofusion fittings for polyethylene pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055-98(2006) (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

B. For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

C. For procedures intended for non-lateral pipe connections, perform tensile testing in accordance with a listed specification. If the test specimen elongates no less than twenty-five percent (25%) or failure initiates outside the joint area, the procedure qualifies for use.

2. Mechanical joints. Before any written procedure established under paragraph (6)(B)2. is used for making mechanical plastic pipe joints, the procedure must be qualified in accordance with a listed specification based upon the pipe material.

3. A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.

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

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

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

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

2. The specimen joint must be—

A. Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

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

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

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

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

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

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

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

4. Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator's system is qualified in accordance with this subsection.

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

(I) Plastic Pipe—Inspection of Joints. (192.287) No person may carry out the inspection of joints in plastic pipes required by paragraphs (6)(B)3. and (6)(H)2. (192.273[c] and 192.285[b]) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

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

(A) Scope. (192.301) This section prescribes minimum requirements for constructing transmission lines and mains.

(B) Compliance With Specifications or Standards. (192.303) Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this rule.

(C) Inspection—General. (192.305) Each transmission line or main must be inspected to ensure that it is constructed in accordance with this rule.

(D) Inspection of Materials. (192.307) Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

(E) Repair of Steel Pipe. (192.309)

1. Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either—

A. The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

B. The nominal wall thickness required for the design pressure of the pipeline.

2. Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of twenty percent (20%) or more of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

A. A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn;

B. A dent that affects the longitudinal weld or a circumferential weld; and

C. In pipe to be operated at a pressure that produces a hoop stress of forty percent (40%) or more of SMYS, a dent that has a depth of—

(I) More than one-quarter inch (1/4") (6.4 millimeters) in pipe twelve and three-quarters inches (12 3/4") (324 millimeters) or less in outer diameter; or

(II) More than two percent (2%) of the nominal pipe diameter in pipe over twelve and three-quarters inches (12 3/4") (324 millimeters) in outer diameter.

For the purpose of this subsection, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

3. Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of forty percent (40%) or more of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either—

A. The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

B. The nominal wall thickness required for the design pressure of the pipeline.

4. A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out.

5. Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

(F) Repair of Plastic Pipe During Construction. (192.311) Each pipe segment containing imperfection or damage that would impair the serviceability of plastic pipe must be removed. For repair of plastic pipe other than during construction, see subsection (13)(AA).

(G) Bends and Elbows. (192.313)

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

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

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

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

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

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

2. Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

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

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

(H) Wrinkle Bends in Steel Pipe. (192.315)

1. A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of thirty percent (30%), or more, of SMYS.

2. Each wrinkle bend on steel pipe must comply with the following:

A. The bend must not have any sharp kinks;

B. When measured along the crotch of the bend, the wrinkles must be a distance of at least one (1) pipe diameter;

C. On pipe sixteen inches (16") (406 millimeters) or larger in diameter, the bend may not have a deflection of more than one and one-half degrees (1 1/2°) for each wrinkle; and

D. On pipe containing a longitudinal weld, the longitudinal seam must be as near as practicable to the neutral axis of the bend.

(I) Protection From Hazards. (192.317)

1. The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.

2. Each aboveground transmission line or main, not located in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

3. Pipelines, including pipe risers, on each platform located in inland navigable waters must be protected from accidental damage by vessels.

(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.

(K) Installation of Plastic Pipe. (192.321)

1. Plastic pipe must be installed below ground level except as provided by paragraphs (7)(K)7., (7)(K)8., and (7)(K)9.

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

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

4. Plastic pipe must have a minimum wall thickness in accordance with (3)(I).

5. Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

6. Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. Plastic pipe that is being encased must be protected from damage at all entrance and all exit points of the casing. The leading end of the plastic must be closed before insertion.

7. Uncased plastic pipe may be temporarily installed above-ground level under the following conditions:

A. The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or two (2) years, whichever is less;

B. The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage; and

C. The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

8. Plastic pipe may be installed on bridges provided that it is—

A. Installed with protection from mechanical damage, such as installation in a metallic casing;

B. Protected from ultraviolet radiation; and

C. Not allowed to exceed the pipe temperature limits specified in subsection (3)(I).

9. Plastic mains may terminate above ground level provided they comply with the following:

A. The above-ground level part of the plastic main is protected against deterioration and external damage;

B. The plastic main is not used to support external loads; and

C. Installations of risers at regulator stations must meet the design requirements of (4)(AA).

(L) Casing. (192.323) Each casing used on a transmission line or main under a railroad or highway must comply with the following:

1. The casing must be designed to withstand the

superimposed loads;

2. If there is a possibility of water entering the casing, the ends must be sealed;

3. If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than seventy-two percent (72%) of SMYS; and

4. If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

(M) Underground Clearance. (192.325)

1. Each transmission line must be installed with at least twelve inches (12") (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

2. Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

3. In addition to meeting the requirements of paragraph (7)(M)1. or 2., each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

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

(N) Cover. (192.327)

1. Except as provided in paragraphs (7)(N)3. and 5., each buried transmission line must be installed with a minimum cover as follows:

Location	**Normal Soil inches**	**Consolidated Rock (millimeters)**
Class 1 locations	30 (762)	18 (457)
Class 2, 3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

2. Except as provided in paragraphs (7)(N)3. and 4., each buried main must be installed with at least twenty-four inches (24") (610 millimeters) of cover.

3. Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

4. A main may be installed with less than twenty-four inches (24") (610 millimeters) of cover if the law of the state or municipality—

A. Establishes a minimum cover of less than twenty-four inches (24") (610 millimeters);

B. Requires that mains be installed in a common trench with other utility lines; and

C. Provides adequately for prevention of damage to the pipe by external forces.

5. Except as provided in paragraph (7)(N)3., all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of forty-eight inches (48") (1219 millimeters) in soil or twenty-four inches (24") (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(O) Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.328). The federal regulations at 49 CFR 192.328 are not adopted in this rule.

(P) Installation of Plastic Pipelines by Trenchless Excavation. (192.329) Plastic pipelines installed by trenchless excavation must comply with the following:

1. Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation; and

2. For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined in subsection (1)(B), to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

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

(A) Scope, Compliance with Specifications or Standards, and Inspections. (192.351) This section prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains. Service lines must be constructed in accordance with comprehensive written specifications or standards that are consistent with this rule. Service lines must be inspected to ensure they are constructed in accordance with this rule. Each service line component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

(B) Service Lines and Yard Lines.

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

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

(C) Customer Meters and Regulators—Location. (192.353)

1. Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.

2. Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

3. Each meter installed within a building must be located in a ventilated place and not less than three feet (3') (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

4. Where feasible, the upstream regulator in a series

must be located outside the building, unless it is located in a separate metering or regulating building.

(D) Customer Meters and Regulators—Protection From Damage. (192.355)

1. Protection from vacuum or back pressure. If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

2. Service regulator vents and relief vents. Service regulator vents and relief vents must terminate outdoors and the outdoor terminal must—

A. Be rain and insect resistant;

B. Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

C. Be protected from damage caused by submergence in areas where flooding may occur.

3. Pits and vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated must be able to support that traffic.

(E) Customer Meters and Regulators—Installation. (192.357)

1. Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

2. When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this rule.

3. Connections made of lead and other easily damaged material may not be used in the installation of meters or regulators.

4. Each regulator equipped with a vent must be vented to the atmosphere outside the building.

(F) Customer Meter Installations—Operating Pressure. (192.359)

1. A meter may not be used at a pressure that is more than sixty-seven percent (67%) of the manufacturer's shell test pressure.

2. Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of ten (10) psi (69 kPa) gauge.

3. A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than fifty percent (50%) of the pressure used to test the meter after rebuilding or repairing.

(G) Service Lines—Installation. (192.361)

1. Depth. Each buried service line must be installed with at least twelve inches (12") (305 millimeters) of cover in private property and at least eighteen inches (18") (457 millimeters) of cover in streets and roads, except a plastic service line that is not inserted in a metallic casing must be installed with at least eighteen inches (18") (457 millimeters) of cover in all locations. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

2. Support and backfill. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

3. Grading for drainage. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

4. Protection against piping strain and external loading. Each service line must be installed so as to minimize anticipated piping strain and external loading.

5. Installation of service lines into buildings. Each underground service line installed below grade through the outer foundation wall of a building must—

A. In the case of a metal service line, be protected against corrosion;

B. In the case of a plastic service line, be protected from shearing action and backfill settlement; and

C. Be sealed at the foundation wall to prevent leakage into the building.

6. Installation of service lines under buildings. Where an underground service line is installed under a building—

A. It must be encased in a gastight conduit;

B. The conduit and the service line must extend, if the service line supplies the building it underlies, into a normally usable and accessible part of the building; and

C. The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

7. Locating underground service lines. Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with paragraph (7)(K)5.

(H) Service Lines—Valve Requirements. (192.363)

1. Each service line must have a service line valve that meets the applicable requirements of sections (2) and (4) of this rule. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service line valve.

2. A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

3. Each service line valve on a high-pressure service line, installed aboveground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

(I) Service Lines—Location of Valves. (192.365)

1. Relation to regulator or meter. Each service line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

2. Outside valves. Each service line must have a shut-off valve in a readily accessible location that is outside of the building.

3. Underground valves. Each underground service line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

(J) Service Lines—General Requirements for Connections to Main Piping. (192.367)

1. Location. Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

2. Compression-type connection to main. Each compression-type service line to main connection must—

A. Be designed and installed to effectively sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading;

B. If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system; and

C. If used on pipelines comprised of plastic, be a Category 1 connection as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

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

1. Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of subsection (6)(B). (192.273)

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

(L) Service Lines—Steel. (192.371) Each steel service line to be operated at less than one hundred (100) psi (689 kPa) gauge must be constructed of pipe designed for a minimum of one hundred (100) psi (689 kPa) gauge.

(M) Service Lines—Plastic. (192.375)

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

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

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

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

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

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

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

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

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

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

6. Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

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

(N) New Service Lines Not in Use. (192.379) Each service line that is not placed in service upon completion of installation must comply with one (1) of the following until the customer is supplied with gas:

1. The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator;

2. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly; or

3. The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

(O) Service Lines—Excess Flow Valve Performance Standards. (192.381)

1. Excess flow valves to be used on service lines that operate continuously throughout the year at a pressure not less than ten (10) psi (69 kPa) must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will—

A. Function properly up to the maximum operating pressure at which the valve is rated;

B. Function properly at all temperatures reasonably expected in the operating environment of the service line;

C. At ten (10) psi (69 kPa) gauge:

(I) Close at, or not more than fifty percent (50%) above, the rated closure flow rate specified by the manufacturer; and

(II) Upon closure, reduce gas flow—

(a) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than five percent (5%) of the manufacturer's specified closure flow rate, up to a maximum of twenty (20) cubic feet per hour (0.57 cubic meters per hours); or

(b) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (0.01 cubic meters per hour); and

D. Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

2. An excess flow valve must meet the applicable requirements of sections (2) and (4).

3. An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

4. An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

5. An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service line, such as blowing liquids from the service line.

(P) Excess Flow Valve Installation. (192.383)

1. Definitions for subsection (8)(P).

A. Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

B. Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

C. Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one (1) single-family residence.

2. Installation required. An excess flow valve (EFV) installation must comply with the performance standards in subsection (8)(O). After April 14, 2017, each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:

A. A single service line to one (1) single family residence;

B. A branched service line to a single family residence installed concurrently with the primary single family residence service line (i.e., a single EFV may be installed to protect both service lines);

C. A branched service line to a single family residence installed off a previously installed single family residence service line that does not contain an EFV;

D. Multifamily residences with known customer loads not exceeding one thousand standard cubic feet per hour (1,000 SCFH) per service, at time of service installation, based on installed meter capacity; and

E. A single, small commercial customer served by a single service line with a known customer load not exceeding one thousand standard cubic feet per hour (1,000 SCFH), at the time of meter installation, based on installed meter capacity.

3. Exceptions to excess flow valve installation requirement. An operator need not install an excess flow valve if one (1) or more of the following conditions are present:

A. The service line does not operate at a pressure of ten (10) psi gauge or greater throughout the year;

B. The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;

C. An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

D. An EFV meeting performance standards in subsection (8)(O) is not commercially available to the operator.

4. Customer's right to request an EFV. Existing service line customers who desire an EFV on service lines not exceeding one thousand standard cubic feet per hour (1,000 SCFH) and who do not qualify for one (1) of the exceptions in paragraph (8)(P)3. may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

5. Operator notification of customers concerning EFV installation. Operators must notify customers of their right to request an EFV in the following manner:

A. Except as specified in (8)(P)3. and (8)(P)5.E., each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, website postings, and e-billing notices;

B. The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks;

C. The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known;

D. The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed one thousand standard cubic feet per hour (1,000 SCFH) and the conditions of paragraph (8)(P)3. are not present, the operator must install an EFV at a mutually agreeable date; and

E. Operators of master-meter systems may continuously post a general notification in a prominent location frequented by customers.

6. Operator evidence of customer notification. An operator must make a copy of the notice or notices currently in use available during inspections conducted by designated commission personnel.

7. Reporting. Except for operators of master meter systems, each operator must report the EFV measures detailed in the annual report required by 20 CSR 4240-40.020(7)(A).

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

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

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

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

(R) Installation of Plastic Service Lines by Trenchless Excavation. (192.376) Plastic service lines installed by trenchless excavation must comply with the following:

1. Each operator shall take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and structures at the time of installation; and

2. For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined in subsection (1)(B), to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

(9) Requirements for Corrosion Control.

(A) Scope. (192.451) This section prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

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

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

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

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

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

3. Type C onshore regulated gathering lines. For any Type C onshore regulated gathering pipeline under subsection (1)(E) of this rule (192.9) existing on May 16, 2022, that was not previously subject to this rule, and for any Type C onshore gas gathering pipeline that becomes subject to section (9) after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site—

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

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

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

(C) General. (192.453) Each operator shall establish written procedures as required by subparagraph (12)(C)2.B. to implement the requirements of this section. Each written procedure, including those for the design, installation, operation, and maintenance of cathodic protection systems, shall be carried out by, or under the direction of, a person qualified by experience and training in pipeline corrosion control methods.

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

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

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

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

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

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

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

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

4. Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of eight (8), unless tests or experience indicate its suitability in the particular environment involved.

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

A. For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

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

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

(E) External Corrosion Control—Buried or Submerged Pipelines Installed Before August 1, 1971. (192.457)

1. Each buried or submerged transmission line and each buried or submerged feeder line or main in excess of one hundred feet (100') installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this section unless definitely scheduled in a replacement program in subsection (15)(E). For the purposes of this section, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

2. Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this section in areas in which active corrosion is found:

A. Bare or ineffectively coated transmission lines;

B. Effectively coated feeder lines and mains not in excess of one hundred feet (100');

C. Bare or ineffectively coated feeder lines or mains; and

D. Bare or coated service lines, except that steel service lines must be replaced as required by subsection (15)(C).

(F) External Corrosion Control—Inspection of Buried Pipeline When Exposed. (192.459) Whenever an operator has knowledge that any portion of a buried metallic pipeline is exposed, an inspection of the exposed portion must be conducted. If the pipe is coated, the condition of the coating must be determined. If the pipe is bare or if the coating is deteriorated, the surface of the pipe must be examined for evidence of external corrosion. If external corrosion requiring remedial action under subsections (9)(R) through (9)(U) (192.483 through 192.489) is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

(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.

(H) External Corrosion Control — Cathodic Protection. (192.463)

1. Each cathodic protection system required by this section must provide a level of cathodic protection that complies with one (1) or more of the applicable criteria contained in Appendix D, which is included herein (at the end of this rule).

2. If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential —

A. The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

B. The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D for amphoteric metals.

3. The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

2. One (1) or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

3. Except for unprotected copper inserted in a ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

4. Inspection and electrical tests must be made to assure that electrical isolation is adequate.

5. An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

6. Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

(K) External Corrosion Control—Test Stations. (192.469) Each pipeline under cathodic protection required by this section must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

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

1. Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

2. Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

3. Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

(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.

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

1. Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

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

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

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

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

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

4. Monitoring. (192.477) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two (2) times each calendar year, but with intervals not exceeding seven and one-half (7 1/2) months.

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

1. Design and construction. Except as provided in paragraph (9)(O)2., each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must—

A. Be configured to reduce the risk that liquids will collect in the line;

B. Have effective liquid removal features whenever the configuration would allow liquids to collect; and

C. Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

2. Exceptions to applicability. The design and construction requirements of paragraph (9)(O)1. do not apply to pipeline installed or line pipe, valve, fitting, or other line component replaced before May 23, 2007.

3. Change to existing transmission line. When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion

risk to the downstream portion of an existing transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

4. Records. An operator must maintain records demonstrating compliance with this subsection. Provided the records show why incorporating design features addressing (9)(O)1.A., (9)(O)1.B., or (9)(O)1.C. is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

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

1. Pipelines installed after July 31, 1971. Each aboveground pipeline or portion of a pipeline installed after July 31, 1971, that is exposed to the atmosphere must be cleaned and coated with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph for an inside pipeline, if the operator can demonstrate by test, investigation or experience appropriate to the inside environment of the pipeline that corrosion will —

A. Only be a light surface oxide; or

B. Not result in pitting of the base metal before the next scheduled inspection.

2. Pipelines installed before August 1, 1971. Each aboveground pipeline or portion of a pipeline installed before August 1, 1971, that is exposed to the atmosphere must be cleaned and coated with a material suitable for the prevention of atmospheric corrosion. This applies to all portions of pipelines in soil-to-air interfaces. For portions of pipelines that are not in soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will —

A. Only be a light surface oxide; or

B. Not affect the safe operation of the pipeline before the next scheduled inspection.

3. For the purposes of this subsection and subsection (9)(Q), atmospheric corrosion means corrosion that has resulted in pitting of the base metal.

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

1. Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion at least once every three (3) calendar years, but with intervals not exceeding thirty-nine (39) months. (Atmospheric corrosion is defined in paragraph (9)(P)3.)

2. During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, at deck penetrations, and in spans over water.

3. If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by subsection (9)(P) within twelve (12) months unless otherwise approved by designated commission personnel.

(R) Remedial Measures — General. (192.483)

1. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of subsection (9)(G). (192.461)

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

3. Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected and monitored in accordance with this section.

(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 must be determined and documented in accordance with subsection (13)(EE).

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

1. General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, or a remaining wall thickness less than thirty percent (30%) of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

2. Localized corrosion pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

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

1. General graphitization. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result must be replaced.

2. Localized graphitization. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

(V) Corrosion Control Records. (192.491)

1. Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode. Each operator shall develop and maintain maps showing, at a minimum, the location of cathodically protected mains (except for short sections less than one hundred feet (100') in length); feeder lines; and transmission lines; and all cathodic protection facilities such as rectifiers, test points (except for service riser locations that are not used each year), electrical isolating

devices that separate protection zones, and interference bonds.

2. Each record or map required by paragraph (9)(V)1. must be retained for as long as the pipeline remains in service.

3. Each operator shall maintain a record of each test, survey, inspection, and remedial action required by this section in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least five (5) years with the following exceptions:

A. Operators must retain records related to paragraphs (9)(I)1., (9)(I)4., (9)(I)5., and (9)(N)2. for as long as the pipeline remains in service; and

B. Operators must retain records of atmospheric corrosion inspections of each pipeline that is being inspected under paragraph (9)(Q) for the longer of the two (2) most recent atmospheric corrosion inspections or five (5) years.

(W) Direct Assessment. (192.490) Each operator that uses direct assessment as defined in 49 CFR 192.903 (see section (16)) on a transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard[1] (see section (16))
External corrosion	49 CFR 192.925[2]
Internal corrosion in pipelines that transport dry gas	49 CFR 192.927
Stress corrosion cracking	49 CFR 192.929

[1]For lines not subject to 49 CFR part 192, subpart O, the terms "covered segment" and "covered pipeline segment" in 49 CFR 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

[2]In 49 CFR 192.925[b], the provision regarding detection of coating damage applies only to pipelines subject to 49 CFR part 192, subpart O.

(X) In-line Inspection of Pipelines. (192.493) When conducting in-line inspections of pipelines required by this rule, an operator must comply with API STD 1163, ANSI/ASNT ILI–PQ, and NACE SP0102 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

(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.

(10) Test Requirements.

(A) Scope. (192.501) This section prescribes minimum leak-test and strength-test requirements for pipelines.

(B) General Requirements. (192.503)

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

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

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

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

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

B. Relatively free of sedimentary materials; and

C. Except for natural gas, nonflammable.

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

Class Location	Maximum Hoop Stress Allowed as Percentage of SMYS	
	Natural Gas	Air or Inert Gas
1	80	80
2	30	75
3	30	50
4	30	40

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

5. If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that —

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

B. The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

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

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

1. Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of thirty percent (30%) or more of SMYS must be strength tested in accordance with this subsection to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within three hundred feet (300') (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least one hundred twenty-five percent (125%) of maximum operating pressure on that segment of the pipeline within three hundred feet (300') (91 meters) of such a building, but in no event may the test section be less than six hundred feet (600') (183 meters) unless the length of the newly installed or relocated pipe is less than six hundred feet (600') (183 meters). However, if the buildings are evacuated while the hoop stress exceeds fifty percent (50%) of SMYS, air or inert gas may be used as the test medium.

2. In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station must be tested to at least Class 3 location test requirements.

3. Except as provided in paragraph (10)(C)4., the strength test must be conducted by maintaining the pressure at or above the test pressure for at least eight (8) hours.

4. For fabricated units and short sections of pipe, for which a post-installation test is impractical, a pre-installation strength test must be conducted by maintaining the pressure at or above the test pressure for at least four (4) hours.

(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) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than thirty percent (30%) of SMYS and at or above one hundred (100) psi (689 kPa) gauge must be tested in accordance with subparagraph (12)(M)1.B. and the following:

1. The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested;

2. If, during the test, the segment is to be stressed to twenty percent (20%) or more of SMYS and natural gas, inert gas, or air is the test medium—

A. A leak test must be made at a pressure between one hundred (100) psi (689 kPa) gauge and the pressure required to produce a hoop stress of twenty percent (20%) of SMYS; or

B. The line must be walked to check for leaks while the hoop stress is held at approximately twenty percent (20%) of SMYS;

3. The pressure must be maintained at or above the test pressure for at least one (1) hour; and

4. For fabricated units and short sections of pipe for which a post-installation test is impractical, a pre-installation pressure test must be conducted in accordance with the requirements of this subsection.

(E) Test Requirements for Pipelines to Operate Below One Hundred (100) psi (689 kPa) Gauge. (192.509) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below one hundred (100) psi (689 kPa) gauge must be leak tested in accordance with the following:

1. The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested; and

2. Each main that is to be operated at less than one (1) psi (6.9 kPa) gauge must be tested to at least ten (10) psi (69 kPa) gauge, each main to be operated at or above one (1) psi (6.9 kPa) gauge through ninety (90) psi (621 kPa) gauge must be tested to at least ninety (90) psi (621 kPa) gauge, and each main that is to be operated between ninety (90) psi (621 kPa) gauge and one hundred (100) psi (689 kPa) gauge must be tested to at least one hundred (100) psi (689 kPa) gauge.

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

1. Each segment of a service line (other than plastic) must be leak tested in accordance with this subsection before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

2. Each segment of a service line (other than plastic) intended to be operated at a pressure of at least one (1) psi (6.9 kPa) gauge but not more than forty (40) psi (276 kPa) gauge must be given a leak test at a pressure of not less than fifty (50) psi (345 kPa) gauge.

3. Each segment of a service line (other than plastic) intended to be operated at pressures of more than forty (40) psi (276 kPa) gauge through ninety (90) psi (621 kPa) gauge must be tested to at least ninety (90) psi (621 kPa) gauge; if the service line is to be operated between ninety (90) psi (621 kPa) gauge and one hundred (100) psi (689 kPa) gauge, it must be tested to at least one hundred (100) psi (689 kPa) gauge; and if the service line may be operated at one hundred (100) psi (689 kPa) gauge; or more, it must, at a minimum, be tested using the appropriate factor in subparagraph (12)(M)1.B. of this rule, except that each segment of the steel service line stressed to twenty percent (20%) or more of SMYS must be tested in accordance with subsection (10)(D).

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

1. Each segment of a plastic pipeline must be tested in accordance with this subsection.

2. The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.

3. The test pressure must be at least one hundred fifty percent (150%) of the maximum allowable operating pressure or fifty (50) psi (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than two and one half (2.5) times the pressure determined under subsection (3)(I), at a temperature not less than the pipe temperature during the test.

4. During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

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

1. In conducting tests under this section, each operator shall ensure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed fifty percent (50%) of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

2. The operator shall ensure that the test medium is disposed of in a manner that will minimize damage to the environment.

(I) Records. (192.517)

1. For pipelines other than service lines, each operator

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

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

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

C. Test pressure;

D. Test duration;

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

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

G. Leaks and failures noted and their disposition;

H. Test date; and

I. Description of facilities being tested.

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

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

1. At the initial time an operator physically turns on the flow of gas to new fuel line installations—

A. Each segment of fuel line must be tested for leakage to at least the delivery pressure;

B. A visual inspection of the exposed, accessible customer gas piping, interior and exterior, and all connected equipment shall be conducted to determine that the requirements of any applicable industry codes, standards or procedures adopted by the operator to assure safe service are met; and

C. The requirements of any applicable local (city, county, etc.) codes must be met.

2. The temperature of thermoplastic material must not be more than one hundred degrees Fahrenheit (100 °F) during the test.

3. A record of the test and inspection performed in accordance with this subsection shall be maintained by the operator for a period of not less than two (2) years.

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

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

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

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

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

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

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

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

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

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

D. Assessment techniques and acceptance criteria;

E. Remediation methods for assessment findings;

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

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

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

(11) Uprating.

(A) Scope. (192.551) This section prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

(B) General Requirements. (192.553)

1. Pressure increases. Whenever the requirements of this section require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled and in accordance with the following:

A. At the end of each incremental increase, the pressure must be held constant while the entire segment of the pipeline that is affected is checked for leaks. When a combustible gas is being used for uprating, all buried piping must be checked with a leak detection instrument after each incremental increase; and

B. Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

2. Records. Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this section, of all work performed, and of each pressure test conducted, in connection with the uprating.

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

4. Limitation on increase in maximum allowable operating pressure. Except as provided in (11)(C)3., a new maximum allowable operating pressure established under this section may not exceed the maximum that would be allowed under subsections (12)(M) and (12)(N) for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula in subsection (3)(C) is unknown, the MAOP may be increased as provided in subparagraph (12)(M)1.A.

5. Establishment of a new maximum allowable operating

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

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

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

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

A. Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this rule; and

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

3. After complying with paragraph (11)(C)2., an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under subsection (12)(M) (192.619), using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

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

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

B. An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if—

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

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

(III) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this rule.

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

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

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

(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)

1. Unless the requirements of this subsection have been met, no person may subject—

A. A segment of steel pipeline to an operating pressure that will produce a hoop stress less than thirty percent (30%) of SMYS and that is above the previously established maximum allowable operating pressure; or

B. A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

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

A. Review the design, operating, and maintenance history of the segment of pipeline;

B. Conduct a leak detection instrument survey (if it has been more than one (1) year since the last survey conducted with a leak detection instrument) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

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

D. Reinforce or anchor offsets, bends, and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;

E. Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

F. If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

3. After complying with paragraph (11)(D)2., the increase in maximum allowable operating pressure must be made in accordance with paragraph (11)(B)5. The pressure must be increased in increments that are equal to ten (10) psi (69 kPa) gauge or twenty-five percent (25%) of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of subparagraph (11)(D)2.F. apply, there must be at least two (2) approximately equal incremental increases.

4. If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses, and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

A. In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill;

B. Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three (3) places where the cover is most likely to be greatest and shall use the greatest cover measured;

C. Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three (3) separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

Allowance inches (millimeters)
Cast Iron Pipe

Pipe Size inches (millimeters)	Pit Cast Pipe	Centrifugally Cast Pipe	Ductile Iron Pipe
3 to 8 (76 to 203)	0.075 (1.91)	0.065 (1.65)	0.065 (1.65)
10 to 12 (254 to 305)	0.08 (2.03)	0.07 (1.78)	0.07 (1.78)
14 to 24 (356 to 610)	0.08 (2.03)	0.08 (2.03)	0.075 (1.91)
30 to 42 (762 to 1067)	0.09 (2.29)	0.09 (2.29)	0.075 (1.91)
48 (1219)	0.09 (2.29)	0.09 (2.29)	0.08 (2.03)
54 to 60 (1372 to 1524)	0.09 (2.29)	— —	— —

D. For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of eleven thousand (11,000) psi (76 MPa) and a modulus of rupture of thirty-one thousand (31,000) psi (214 MPa).

(12) Operations.

(A) Scope. (192.601) This section prescribes minimum requirements for the operation of pipeline facilities.

(B) General Provisions. (192.603)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

H. Periodically reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found;

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

J. Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available, when needed at the excavation, emergency rescue equipment including a breathing apparatus and a rescue harness and line;

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

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

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

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

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

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

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

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

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

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

(I) Unintended closure of valves or shutdowns;

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

(III) Loss of communications;

(IV) Operation of any safety device; and

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

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

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

D. Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found; and

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

4. Safety-related conditions. The manual required by paragraph (12)(C)1. must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the commission's reporting requirements.

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

(D) Qualification of Pipeline Personnel.

1. Scope. (192.801)

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

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

(I) Is performed on a pipeline facility;

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

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

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

2. Definitions. (192.803)

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

(I) Indicate a condition exceeding design limits;

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

(III) Require an emergency response.

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

(I) Written examination;

(II) Oral examination;

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

(a) Performance on the job;

(b) On the job training; or

(c) Simulations.

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

(I) Perform assigned covered tasks; and

(II) Recognize and react to abnormal operating conditions.

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

A. Identify covered tasks;

B. Provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities;

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

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

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

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

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

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

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

J. Ensure that covered tasks are—

(I) Performed by qualified individuals; or

(II) Directed and observed by qualified individuals; and

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

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

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

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

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

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

E. Recognize potential ignition sources;

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

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

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

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

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

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

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

A. Qualification records shall include:

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

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

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

(IV) Qualification method(s).

B. Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five (5) years.

9. General. (192.809)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(F) Change in Class Location — Required Study. (192.609) Whenever an increase in population density indicates a change in class locations for a segment of an existing steel pipeline operating at a hoop stress that is more than forty percent (40%) of SMYS or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine —

1. The present class location for the segment involved;

2. The design, construction, and testing procedures followed in the original construction and a comparison for these procedures with those required for the present class location by the applicable provisions of this rule;

3. The physical condition of the segment to the extent it can be ascertained from available records;

4. The operating and maintenance history of the segment;

5. The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

6. The actual area affected by the population density increase and physical barriers or other factors which may limit further expansion of the more densely populated area.

(G) Change in Class Location — Confirmation or Revision of Maximum Allowable Operating Pressure. (192.611) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one (1) of the following three (3) paragraphs:

1. If the segment involved has been previously tested in place for a period of not less than eight (8) hours, the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed seventy-two percent (72%) of SMYS of the pipe in Class 1 and 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of SMYS in Class 4 locations;

2. The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this rule for new segments of pipelines in the existing class location; or

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

A. The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations and 0.555 times the test pressure for Class 4 locations; and

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

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

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

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

(H) Continuing Surveillance. (192.613)

1. Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.

2. If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with paragraphs (12)(M)1. and 2. (192.619[a] and [b])

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

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

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

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

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

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

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

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

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

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

(I) Damage Prevention Program. (192.614)

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

2. An operator may perform any of the duties specified in paragraph (12)(I)3. through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this subsection. However, an operator must perform the duties of subparagraph (12)(I)3.D. through participation in the qualified one-call system for Missouri. An operator's pipeline system must be covered by the qualified one-call system for Missouri.

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

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

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

(II) Telephone company;

(III) Electric utilities and co-ops;

(IV) Water and sewer utilities;

(V) City governments;

(VI) County governments;

(VII) Special road districts;

(VIII) Special water and sewer districts; and

(IX) Highway department district(s);

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

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

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

(II) Provide for at least semiannual educational mailings to the excavators named on the comprehensive listing maintained pursuant to part (12)(I)3.C.(I), by first class mail; and

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

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

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

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

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

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

F. If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings;

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

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

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

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

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

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

B. The proximity to the operator's facilities;

C. The type of excavating equipment involved;

D. The importance of the operator's facilities;

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

F. The potential for serious incident should damage occur;

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

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

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

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

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

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

7. Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

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

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

(J) Emergency Plans. (192.615)

1. Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

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

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

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

(I) Gas detected inside or near a building;

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

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

(IV) Natural disaster;

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

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

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

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

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

I. Safely restoring any service outage;

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

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

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

2. Each operator shall—

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

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

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

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

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

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

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

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

(K) Public Awareness. (192.616)

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

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

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

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

2. The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

3. The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

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

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

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

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

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

E. Procedures for reporting such an event.

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

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

7. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

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

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

10. Unless the operator transports gas as a primary activity,

the operator of a master meter is not required to develop a public awareness program as prescribed in paragraphs (12)(K)1.–7. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the master meter is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

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

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

C. Information about damage prevention;

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

E. How to get additional information.

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

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

2. Post-failure and incident lessons learned. Each operator 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 paragraph (1)(E)2.) that first became subject to this rule after April 13, 2006.	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 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. The notification must include the following information:

(I) The proposed MAOP of the pipeline;

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

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

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

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

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

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

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

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

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

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

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

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

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

1. No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

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

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

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

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

E. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

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

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

1. No person may operate a low-pressure distribution system at a pressure greater than —

A. A pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas utilization equipment; or

B. An equivalent of fourteen inches (14") water column.

2. No person may operate a low-pressure distribution system at a pressure lower than —

A. The minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas utilization equipment can be assured; or

B. An equivalent of four inches (4") water column.

(P) Odorization of Gas. (192.625)

1. A combustible gas in a transmission line or distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth (1/5) of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell. However, for transmission lines in operation before May 28, 1995, the section of transmission line between the supplier's delivery point and the odorizer need not meet the requirements of this paragraph.

2. For installations made after May 28, 1995, a combustible gas in a transmission line must comply with the requirements of paragraph (12)(P)1., and the odorizer must be located as close as practical to the delivery point from the supplier.

3. In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

A. The odorant may not be deleterious to persons, materials, or pipe; and

B. The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

4. The odorant may not be soluble in water to an extent greater than two and one-half (2 1/2) parts to one hundred (100) parts by weight.

5. Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

6. To assure the proper concentration of odorant in accordance with this subsection, each operator must conduct, at least monthly, odor intensity tests with an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. At individually odorized service lines, the odor intensity shall be checked at least once each calendar year at intervals not to exceed fifteen (15) months. Operators of master meter systems may comply with this paragraph by —

A. Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

B. Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

7. All odorant tanks should be checked periodically to assure adequate odorant is available. Odorant injection rates can be a useful monitoring tool for some systems. Each operator should consider when and where to use odorant injection rates.

(Q) Tapping Pipelines Under Pressure. (192.627) Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

(R) Purging of Pipelines. (192.629)

1. When a pipeline is being purged of air by use of gas, the gas must be released into one (1) end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

2. When a pipeline is being purged of gas by use of air, the air must be released into one (1) end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

(S) Providing Service to Customers.

1. At the time an operator physically turns on the flow of gas to a customer (see requirements in subsection (10)(J) for new fuel line installations) —

A. Each segment of fuel line must be tested for leakage to at least the delivery pressure; and

B. A visual inspection of the exposed, accessible customer gas piping, interior and exterior, and all connected equipment shall be conducted to determine that the requirements of any applicable industry codes, standards, or procedures adopted by the operator to assure safe service are met. This visual inspection need not be met for emergency outages or curtailments. In the event a large commercial or industrial customer denies an operator access to the customer's premises, the operator does not need to comply with the above requirement if the operator obtains a signed statement from the customer stating that the customer will be responsible for inspecting its exposed, accessible gas piping, and all connected equipment, to determine that the piping and equipment meets any applicable codes, standards, or procedures adopted by the operator to assure safe service. In the event the customer denies an operator access to its premises and refuses to sign a statement as described above, the operator may file with the commission an application for waiver of compliance with this provision.

2. When providing gas service to a new customer or a customer relocated from a different operating district, the operator must provide the customer with the following as soon as possible, but within seven (7) calendar days, unless the operator can demonstrate that the information would be the same:

A. Information on how to contact the operator in the event of an emergency or to report a gas odor;

B. Information on how and when to contact the operator when excavation work is to be performed; and

C. Information concerning the customer's responsibility for maintaining his/her gas piping and utilization equipment. In addition, the operator should determine if a customer notification is applicable per subsection (1)(K).

3. The operator shall discontinue service to any customer whose fuel lines or gas utilization equipment are determined to be unsafe. The operator, however, may continue providing service to the customer if the unsafe conditions are removed or effectively eliminated.

4. A record of the test and inspection performed in accordance with this subsection shall be maintained by the operator for a period of not less than two (2) years.

(T) Control Room Management. (192.631)

1. General.

A. This subsection applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this subsection, except as follows. For each control room where an operator's activities are limited to either or both of distribution with less than two hundred fifty thousand (250,000) services or transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (12)(T)4. (regarding fatigue), (12)(T)9. (regarding compliance validation), and (12)(T)10. (regarding compliance and deviations).

B. The procedures required by this subsection must be integrated, as appropriate, with operating and emergency procedures required by subsections (12)(C) and (12)(J). An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraph (12)(T)2.; subparagraphs (12)(T)3.E. and (12)(T)4.B. and C.; and paragraphs (12)(T)6. and (12)(T)7. must be implemented no later than October 1, 2011. The procedures required by subparagraphs (12)(T)3.A.–D. and (12)(T)4.A. and D.; and paragraph (12)(T)5. must be implemented no later than August 1, 2012. The training procedures required by paragraph (12)(T)8. must be implemented no later than August 1, 2012, except that any training required by another paragraph or subparagraph of this subsection must be implemented no later than the deadline for that paragraph or subparagraph.

2. Roles and responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

A. A controller's authority and responsibility to make decisions and take actions during normal operations;

B. A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

C. A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others;

D. A method of recording controller shift-changes and any hand-over of responsibility between controllers; and

E. The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

3. Provide adequate information. Each operator must provide its controllers with the information, tools, processes, and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

A. Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)) whenever a SCADA system is added, expanded, or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

B. Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

C. Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed fifteen (15) months;

D. Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed fifteen (15) months; and

E. Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

4. Fatigue mitigation. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

A. Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight (8) hours of continuous sleep;

B. Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

C. Train controllers and supervisors to recognize the effects of fatigue; and

D. Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

5. Alarm management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

A. Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

B. Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

C. Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed fifteen (15) months;

D. Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding fifteen (15) months, to determine the effectiveness of the plan;

E. Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed fifteen (15) months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

F. Address deficiencies identified through the implementation of subparagraphs (12)(T)5.A.–E.

6. Change management. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

A. Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;

B. Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and

C. Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

7. Operating experience. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

A. Review federal incidents that must be reported pursuant to 20 CSR 4240-40.020 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to—

(I) Controller fatigue;

(II) Field equipment;

(III) The operation of any relief device;

(IV) Procedures;

(V) SCADA system configuration; and

(VI) SCADA system performance; and

B. Include lessons learned from the operator's experience in the training program required by this subsection.

8. Training. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed fifteen (15) months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

A. Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

B. Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

C. Training controllers on their responsibilities for communication under the operator's emergency response procedures;

D. Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions;

E. For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application; and

F. Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal, or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.

9. Compliance validation. Operators must submit their procedures to designated commission personnel per subsection (1)(J).

10. Compliance and deviations. An operator must maintain for review during inspection—

A. Records that demonstrate compliance with the requirements of this subsection; and

B. Documentation to demonstrate that any deviation from the procedures required by this subsection was necessary for the safe operation of a pipeline facility.

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

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

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

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

(II) A Class 3 or Class 4 location.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 1

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

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

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

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

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

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

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

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

(VI) Operational monitoring procedures;

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

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

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

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

1. ECA Analysis.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

1. If a class location change on a transmission pipeline occurs after October 5, 2022, and results in pipe replacement, of two (2) or more miles, in the aggregate, within any five (5) contiguous miles within a twenty-four- (24-) month period, to meet the maximum allowable operating pressure (MAOP) requirements in subsections (12)(G) or (12)(M), then the requirements in subsections (4)(U), (12)(X), and (12)(Z), as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those subsections. Such valves must be installed within twenty-four (24) months of the class location change in accordance with the timing requirement in paragraph (12)(G)6. for compliance after a class location change.

2. If a class location change on a gas transmission pipeline occurs after October 5, 2022, and results in pipe replacement of less than two (2) miles within five (5) contiguous miles during a twenty-four- (24-) month period, to meet the MAOP requirements in subsection (12)(G) or (12)(M), then within twenty-four (24) months of the class location change, in accordance with paragraph (12)(G)6., the operator must either —

A. Comply with the valve spacing requirements of paragraph (4)(U)1. for the replaced pipeline segment; or

B. Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two (2) RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment must not exceed twenty (20) miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of subsection (12)(Z).

3. The provisions of paragraph (12)(W)2. do not apply to pipeline replacements that amount to less than one thousand feet (1,000') within any one (1) contiguous mile during any twenty-four- (24-) month period.

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

1. Applicability. For new or entirely replaced transmission pipeline segments with diameters of six inches (6") or greater that are located in high-consequence areas (HCA) or Class 3 or Class 4 locations and that are installed after April 10, 2023, an operator must install or use existing rupture mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this subsection and subsections (4)(U) and (12)(Z). RMVs and alternative equivalent technologies must be operational within fourteen (14) days of placing the new or replaced pipeline segment into service. An operator may request an extension of this fourteen- (14-) day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in subsection (1)(M), that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this subsection apply to all applicable pipe replacement projects, even those that do not otherwise involve the addition or replacement of a valve. This subsection does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR), as defined in 49 CFR 192.903 (incorporated by reference in section (16)), that is less than or equal to one hundred fifty feet (150').

2. Maximum spacing between valves. RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements:

A. Shut-off segment. For purposes of this subsection, a "shut-off segment" means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two (2) RMVs or alternative equivalent technologies. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in subsection (1)(B), or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within thirty (30) minutes following rupture identification, as that term is defined in subsection (1)(B). Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with subsection (1)(M);

B. Shut-off segment valve spacing. A pipeline subject to paragraph (12)(X)1. must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed —

(I) Eight (8) miles for any Class 4 location;

(II) Fifteen (15) miles for any Class 3 location; or

(III) Twenty (20) miles for all other locations;

C. Laterals. Laterals extending from shut-off segments that contribute less than five percent (5%) of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all of the laterals contributing gas volumes to the shut-off segment do not contribute more than five percent (5%) of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are twelve inches (12") in diameter or less, a check valve that allows gas to flow freely in one (1) direction and contains a mechanism to automatically prevent flow in the other direction may be used as an alternative equivalent technology where it is positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this paragraph are not subject to subsection (12)(Z), but they must be inspected, operated, and remediated in accordance with subsection (13)(U), including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify PHMSA in accordance with subsections (1)(M) and (4)(U), and develop and implement maintenance procedures for such equipment that meet subsection (13)(U); and

D. Crossovers. An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify PHMSA in accordance with subsections (1)(M) and (4)(U).

(Y) Notification of Potential Rupture. (192.635)

1. As used in this rule, a "notification of potential rupture" refers to the notification of, or observation by, an operator (e.g., by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one (1) or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline:

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

B. An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting subparagraph (12)(Y)1.A.; or

C. Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline.

2. A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph (12)(Y)1.

(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 this subsection. 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.

8. Manual operation upon identification of a rupture. Operators using a manual valve as an alternative equivalent technology as authorized pursuant to subsections (1)(M), (4)(U), (12)(X), and this subsection must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shutoff in accordance with this subsection and subsection (12)(X). 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. or (12)(Z)3.

(13) Maintenance.

(A) Scope. (192.701) This section prescribes minimum requirements for maintenance of pipeline facilities.

(B) General. (192.703)

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

2. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

3. Leaks must be investigated, classified, and repaired in accordance with section (14).

(C) Transmission Lines—Patrolling. (192.705)

1. Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

2. The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Maximum Interval Between Patrols

Class Location of Line	At Highway and Railroad Crossing Locations	At All Other Locations
1, 2	7 1/2 months; but at least twice each calendar year	15 months; but at least once each calendar year
3	4 1/2 months; but at least four times each calendar year	7 1/2 months; but at least twice each calendar year
4	4 1/2 months; but at least four times each calendar year	4 1/2 months; but at least four times each calendar year

3. Methods of patrolling include walking, driving, flying, or other appropriate means of traversing the right-of-way.

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

1. Instrument leak detection surveys of a transmission line must be conducted—

A. In Class 3 locations, at intervals not exceeding seven and one-half (7 1/2) months but at least twice each calendar year;

B. In Class 4 locations, at intervals not exceeding four and one-half (4 1/2) months but at least four (4) times each calendar year; and

C. In all other locations, at intervals not exceeding fifteen (15) months but at least once each calendar year.

2. Distribution lines, yard lines, and buried fuel lines connected to a transmission line must be leak surveyed in accordance with subsection (13)(M).

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

1. Buried pipelines. Except as provided in paragraph (13)(E)2., a line marker must be placed and maintained as close as practical over each buried main and transmission line—

A. At each crossing of a public road or railroad. Some crossings may require markers to be placed on both sides due to visibility limitations or crossing widths; and

B. Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

2. Exceptions for buried pipelines. Line markers are not required for the following buried pipelines—

A. Mains and transmission lines located at crossings of or under waterways and other bodies of water;

B. Feeder lines and transmission lines located in Class 3 or Class 4 locations where placement of a marker is impractical; or

C. Mains other than feeder lines in Class 3 or Class 4 locations where a damage prevention program is in effect under (12)(I).

3. Pipelines aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground.

4. Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker:

A. The word "Warning," "Caution," or "Danger," followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch (1") (25 millimeters) high with one-quarter inch (1/4") (6.4 millimeters) stroke; and

B. The name of the operator and telephone number (including area code) where the operator can be reached at all times.

(F) Record Keeping. (192.709)

1. For transmission lines each operator shall keep records covering each leak discovered, repair made, line break, leakage survey, line patrol, and inspection for as long as the segment of transmission line involved remains in service. (192.709)

2. For feeder lines, mains, and service lines, each operator shall maintain—

A. Records pertaining to each original leak report for not less than six (6) years;

B. Records pertaining to each leak investigation and classification for not less than six (6) years. These records shall at least contain sufficient information to determine if proper assignment of the leak class was made, the promptness of actions taken, the address of the leak and the frequency of reevaluation and/or reclassification;

C. Records pertaining to each leak repair for the life of the facility involved, except no record is required for repairs of aboveground Class 4 leaks. These records shall at least contain sufficient information to determine the promptness of actions taken, address of the leak, pipe condition at the leak site, leak classification at the time of repair, and other such information necessary for proper completion of DOT annual Distribution and Transmission Line report forms (PHMSA F 7100.1-1 and PHMSA F 7100.2-1); and

D. Records pertaining to leakage surveys and line patrols conducted over each segment of pipeline for not less than six (6) years. These records shall at least contain sufficient information to determine the frequency, scope, and results of the leakage survey or line patrol.

3. For yard lines and buried fuel lines, each operator shall maintain records of notifications and leakage surveys required by subsection (13)(M) for not less than six (6) years.

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

1. Temporary repairs. Each operator must take immediate temporary measures to protect the public whenever—

A. A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above forty percent (40%) of the SMYS; and

B. It is not feasible to make a permanent repair at the time of discovery.

2. Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following:

A. Non-integrity management repairs for gathering lines. For gathering lines subject to this subsection in accordance with subsection (1)(E), an operator must make permanent repairs as soon as feasible;

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

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.

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

1. Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above forty percent (40%) of SMYS must be—

A. Removed by cutting out and replacing a cylindrical piece of pipe; or

B. Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

2. Operating pressure must be at a safe level during repair operations.

(I) Transmission Lines—Permanent Field Repair of Welds. (192.715) Each weld that is unacceptable under paragraph (5)(I)3. (192.241[c]) must be repaired as follows:

1. If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of subsection (5)(K) (192.245);

2. A weld may be repaired in accordance with subsection (5)(K) (192.245) while the segment of transmission line is in service if—

A. The weld is not leaking;

B. The pressure in the segment is reduced so that it does not produce a stress that is more than twenty percent (20%) of the SMYS of the pipe; and

C. Grinding of the defective area can be limited so that at least one-eighth inch (1/8") (3.2 millimeters) thickness in the pipe weld remains; and

3. A defective weld which cannot be repaired in accordance with paragraph (13)(I)1. or 2. must be repaired by installing a full encirclement welded split sleeve of appropriate design.

(J) Transmission Lines—Permanent Field Repair of Leaks. (192.717). Each permanent field repair of a leak on a transmission line must be made by—

1. Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

2. Repairing the leak by one (1) of the following methods:

A. Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than forty percent (40%) of SMYS;

B. If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp;

C. If the leak is due to a corrosion pit and on pipe of not more than forty thousand (40,000) psi (276 MPa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half (1/2) of the diameter of the pipe in size;

D. If the leak is on a submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design; or

E. Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

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

1. Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

2. Testing of repairs made by welding. Each repair made by welding in accordance with subsections (13)(H), (I), and (J) (192.713, 192.715, and 192.717) must be examined in accordance with subsection (5)(I). (192.241)

(L) Distribution Systems—Patrolling. (192.721)

1. The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage and the consequent hazards to public safety.

2. Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

A. In business districts, at intervals not exceeding four and one-half (4 1/2) months but at least four (4) times each calendar year; and

B. Outside business districts, at intervals not exceeding seven and one-half (7 1/2) months, but at least twice each calendar year.

3. Feeder lines shall be patrolled at intervals not exceeding fifteen (15) months but at least once each calendar year.

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

1. Each operator of a distribution line or system shall conduct periodic instrument leakage surveys in accordance with this subsection.

2. The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions but it must meet the following minimum requirements:

A. An instrument leak detection survey must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding fifteen (15) months but at least once each calendar year;

B. Except as provided for in subparagraph (13)(M)2.C., instrument leak detection surveys must be conducted outside of business districts as frequently as necessary, but at intervals not exceeding—

(I) Fifteen (15) months, but at least once each calendar year, for unprotected steel pipelines and unprotected steel yard lines;

(II) Thirty-nine (39) months, but at least once each third calendar year, for all other pipelines and yard lines; and

(III) Thirty-nine (39) months, but at least once each third calendar year, for buried fuel lines operating above low pressure, except for buried fuel lines to large commercial/industrial customers that are notified in accordance with paragraph (13)(M)3. Instrument leak detection surveys of buried fuel lines may be conducted around a portion of the perimeter of the building. This perimeter-type survey shall be conducted along the side of the building nearest the meter location (or the fuel line entrances in the case of multiple buildings) and along the closest adjacent side; and

C. For yard lines and buried fuel lines that are required to be leak surveyed under subparagraph (13)(M)2.B., but are located within high security areas such as prisons, notifications to the customer as described in paragraph (13)(M)3. may be conducted instead of a leak survey.

3. The operator must notify large commercial/industrial customers with buried fuel lines operating above low pressure at one (1) or more buildings, that are not leak surveyed in accordance with part (13)(M)2.B.(III), that maintenance is the customer's responsibility and leak surveys should be conducted. Notification must be provided once each third calendar year, at intervals not exceeding thirty-nine (39) months.

4. Record keeping requirements for leak surveys and notifications are contained in subsection (13)(F).

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

1. Except as provided in paragraphs (13)(N)2. and 4., each disconnected service line must be tested in the same manner as a new service line and the associated fuel line must meet the requirements of subsection (12)(S) before being reinstated.

2. Before reconnecting, each service line temporarily disconnected from the transmission line or main for any reason must be tested from the point of disconnection to the service line valve in the same manner as a new service line. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested. If continuous service is not maintained, the requirements in subsection (12)(S) must be met for the associated fuel line.

3. Except for system outages, each fuel line to which service has been discontinued shall have service resumed in accordance with subsection (12)(S). Each fuel line restored after a system outage shall have service resumed in accordance with subparagraph (12)(S)1.A. and the procedures required under subparagraph (12)(J)1.I. (192.615[a][9])

4. Each service line temporarily disconnected from the transmission line or main due to third party damage must be tested from the point of disconnection to the main in the same manner as a new service line, or it may be surveyed from the point of disconnection to the main using a leak detection instrument.

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

1. Each operator shall perform abandonment or deactivation of pipelines in accordance with the requirements of this subsection.

2. Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas, and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

3. Except for service lines, each inactive pipeline that is not being maintained under this rule must be disconnected from all sources and supplies of gas, purged of gas, and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

4. Whenever service to a customer is discontinued, one (1) of the following must be complied with:

A. The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator;

B. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly; or

C. The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

5. If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging.

6. Each abandoned vault must be filled with a suitable compacted material.

7. For each abandoned pipeline facility that crosses over, under, or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. The addresses (mail and email) and phone numbers given in this paragraph are from 49 CFR 192.727(g) as published on October 1, 2009. Please consult the current edition of 49 CFR part 192 for any updates to these addresses and phone numbers.

A. The preferred method to submit data on pipeline facilities abandoned after October 10, 2000, is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at www.npms.phmsa.dot.gov or contact the NPMS National Repository at (703) 317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax, or email to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE, Washington, DC 20590-0001; fax (202) 366-4566; email, InformationResourcesManager@phmsa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

B. *(Reserved)*

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

1. Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with subsections (13)(R) and (T) (192.739 and 192.743), and must be operated periodically to determine that it opens at the correct set pressure.

2. Any defective or inadequate equipment found must be promptly repaired or replaced.

3. Each remote control shutdown device must be inspected and tested at intervals not exceeding fifteen (15) months but at least once each calendar year to determine that it functions properly.

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

1. Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

2. Aboveground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

3. Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

A. Constructed so that at least fifty percent (50%) of its upright side area is permanently open; or

B. Located in an unattended field compressor station of one thousand (1,000) horsepower (746 kW) or less.

4. Except when shutdown of the system is necessary for maintenance under paragraph (13)(Q)5., each gas detection and alarm system required by this subsection must—

A. Continuously monitor the compressor building for a concentration of gas in air of not more than twenty-five percent (25%) of the lower explosive limit; and

B. If gas at that concentration is detected, warn persons about to enter the building and persons inside the building of the danger.

5. Each gas detection and alarm system required by this subsection must be maintained to function properly. The maintenance must include performance tests.

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

1. Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding fifteen (15) months but at least once each calendar year to inspections and tests to determine that it is—

A. In good mechanical condition;

B. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

C. Except as provided in paragraph (13)(R)2., set to control or relieve at the correct pressures that will prevent downstream pressures from exceeding the allowable pressures under subsections (4)(FF) and (12)(M)–(O);

D. Properly installed and protected from dirt, liquids, and other conditions that might prevent proper operation;

E. Properly protected from unauthorized operation of valves in accordance with paragraph (4)(EE)8.;

F. Equipped to indicate regulator malfunctions in accordance with paragraphs (4)(EE)10. and 11. in a manner that is adequate from the standpoint of reliability of operation; and

G. Equipped with adequate over-pressure protection in accordance with paragraph (4)(EE)9.

2. For steel pipelines whose MAOP is determined under paragraph (12)(M)3., if the MAOP is sixty (60) psi (four hundred fourteen (414) kPa) gauge or more, the control or relief pressure limit is as follows:

A. If the MAOP produces a hoop stress that is greater than seventy-two percent (72%) of SMYS, then the pressure limit is MAOP plus four percent (4%); or

B. If the MAOP produces a hoop stress that is unknown as a percentage of SMYS, then the pressure limit is a pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

3. For individual service lines directly connected to production, gathering, or transmission pipelines, requirements for inspecting and testing devices and equipment are provided in subsection (13)(BB).

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

1. Each distribution system supplied by more than one (1) district pressure regulating station and/or furnishing service to more than one thousand (1000) customers must be equipped with graphic telemetering, recording pressure gauges, or another device (other than pressure gauges unless they are continuously monitored) to indicate the gas pressure in the district.

2. On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation and other operating conditions.

3. If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

4. All telemetered or recorded pressure data shall be identified, dated, and kept on file for a minimum of two (2) years.

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

1. Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in paragraph (13)(R)2., these devices must have sufficient capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure which does not exceed the pressure allowed by subsection (4)(FF). This capacity must be determined at intervals not exceeding fifteen (15) months, but at least once each calendar year, by testing the devices in place or by review and calculations.

2. If review and calculations are used to determine if a relief device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

3. If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (13)(T)1.

(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.

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

1. Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked for accessibility and serviced at intervals not exceeding fifteen (15) months but at least once each calendar year.

2. Feeder line and distribution line valves, the use of which may be necessary for the safe operation of a distribution system, shall be inspected at intervals not exceeding fifteen (15) months but at least once each calendar year. At a minimum, the valves that are metallic must be partially operated during alternating calendar years.

3. Valves necessary for the safe operation of a distribution system include, but are not limited to, those which provide:

A. One hundred percent (100%) isolation of the system or any portion of it;

B. Control of a district regulator station, preferably from a remote location;

C. Zones of isolation sized such that the operator could relight the lost customer services within a period of eight (8) hours after restoration of system pressure; or

D. Extensive zone isolation capabilities where historical records indicate conditions of greater than normal pipeline failure risk.

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

(W) Vault Maintenance. (192.749)

1. Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of two hundred (200) cubic feet (5.66 cubic meters) or more must be inspected at intervals not exceeding fifteen (15) months but at least once each calendar year to determine that it is in good physical condition and adequately ventilated.

2. If gas is found in the vault, the equipment in the vault must be inspected for leaks and any leaks found must be repaired.

3. The ventilating equipment must also be inspected to determine that it is functioning properly.

4. Each vault cover must be inspected to assure that it does not present a hazard to public safety.

(X) Prevention of Accidental Ignition. (192.751) Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

1. When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided;

2. Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work; and

3. Warning signs shall be posted, where appropriate.

(Y) Caulked Bell and Spigot Joints. (192.753)

1. Each cast iron caulked bell and spigot joint that is subject to pressures of more than twenty-five (25) psi (172 kPa) gauge must be sealed with —

A. A mechanical leak clamp; or

B. A material or device which —

(I) Does not reduce the flexibility of the joint;

(II) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(III) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of paragraphs (2)(B)1. and 2. and subsection (4)(B). (192.53[a] and [b] and 192.143)

2. Each cast iron caulked bell and spigot joint that is subject to pressures of twenty-five (25) psi (172 kPa) gauge or less and is exposed for any reason must be sealed by a means other than caulking.

(Z) Protecting or Replacing Disturbed Cast Iron Pipelines. (192.755) When an operator has knowledge that the support for a segment of a buried cast iron pipeline is disturbed or that an excavation or erosion is nearby, the operator shall determine if more than half the pipe diameter lies within the area of affected soil. For the purposes of this subsection, “area of affected soil” refers to the area above a line drawn from the bottom of the excavation or erosion, at the side nearest the main, at a forty-five degree (45°) angle from the horizontal (a lesser angle should be used for sandy or loose soils, or a greater angle may be used for certain consolidated soils if the angle can be substantiated by the operator). If more than half the pipe diameter lies within the area of affected soil, the following measures/precautions must be taken—

1. That segment of the pipeline must be protected, as necessary, against damage during the disturbance by—

A. Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

B. Impact forces by vehicles;

C. Earth movement;

D. Water leaks or sewer failures that could remove or undermine pipe support;

E. Apparent future excavations near the pipeline; or

F. Other foreseeable outside forces which may subject that segment of the pipeline to bending stress;

2. If eight inches (8") or less in nominal diameter, then as soon as feasible, this segment of cast iron pipeline, which shall include a minimum of ten feet (10') beyond the area of affected soil, must be replaced, except as noted in paragraph (13)(Z)4.;

3. If greater than eight inches (8") in nominal diameter, then as soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of subsection (7)(J) (192.319) and paragraph (7)(I)1. (192.317[a]); and

4. Replacement of cast iron pipelines would not necessarily be required if—

A. The support beneath the pipe is removed for a length less than ten (10) times the nominal pipe diameter not to exceed six feet (6');

B. For parallel excavations, the pipe lies within the area of affected soil for a length less than ten (10) times the nominal pipe diameter not to exceed six feet (6');

C. The excavation is made by the operator in the course of routine maintenance, such as leak repairs to the main or service line installation, where the exposed portion of the main does not exceed six feet (6'), and the backfill supporting the pipe is replaced and compacted by the operator; or

D. Permanent or temporary shoring was adequately installed to protect the cast iron pipeline during excavation and backfilling.

(AA) Repair of Plastic Pipe. (192.720) Each leak, imperfection, or damage that impairs the serviceability of a plastic pipe must be removed, except that heat fusion patching saddles may be used to repair holes that have been tapped into the main for service installations, and full-encirclement heat fusion couplings may be used to repair and reinforce butt fusion joints. These patching saddles and couplings shall not be used for the repair of any imperfections or third-party damage sustained by the plastic pipe.

(BB) Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Regulated Gathering or Transmission Pipelines. (192.740)

1. This subsection applies, except as provided in paragraph (13)(BB)3., to any service line directly connected to a transmission pipeline or regulated gathering pipeline as determined in subsection (1)(E) of this rule (192.8) that is not operated as part of a distribution system.

2. Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every three (3) calendar years, not exceeding thirty-nine (39) months, to determine that it is—

A. In good mechanical condition;

B. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

C. Set to control or relieve at the correct pressure consistent with the pressure limits of subsection (4)(DD); and to limit the pressure on the inlet of the service regulator to sixty (60) psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and

D. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

3. This subsection does not apply to equipment installed on—

A. A service line that only serves engines that power irrigation pumps; or

B. A service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in subsection (1)(E) of this rule (192.8).

(CC) Joining Plastic Pipe by Heat Fusion; Equipment Maintenance and Calibration. (192.756) Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer’s recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

(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).

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), (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 subsection, 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. 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).

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) 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 paragraph (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.

(FF) Launcher and Receiver Safety. (192.750) Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g., inspection tools, scrapers, or spheres), if pressure has not been relieved.

(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).

(14) Gas Leaks.

(A) Scope. This section prescribes the procedures for the investigation and classification of gas leaks and for scheduling the repair of these leaks.

(B) Investigation and Classification Procedures.

1. Each operator-detected leak indication or any leak or odor call from the general public, police, fire, or other authorities or notification of damage to facilities by contractors or other outside sources shall require immediate investigation and classification.

2. Investigation of each inside leak or odor notice shall include the use of gas detection equipment upon initial entry into the structure and during investigations within the structure. When investigating an outside leak or odor notice, special attention must be given to those situations where conditions could impair the venting of natural gas to the atmosphere or impair the ability of gas detection equipment to properly detect the presence of gas, such as excessive ground moisture, rain, snow, frozen soil, or wind.

3. Investigation of underground leaks shall be conducted using gas detection equipment. Sampling of the subsurface atmosphere shall be done at sufficient intervals and locations to assure safety to persons and property in the immediate and adjacent area.

4. Except for obvious Class 1 leaks, all leak classifications shall be substantiated by the use of gas detection equipment.

5. A follow-up leak investigation shall be conducted immediately after the repair of each Class 1 or Class 2 leak, and continued as necessary, to determine the effectiveness of the repair and to assure all hazardous leaks in the affected area are corrected.

6. Whenever the operator conducts work on a customer's premises for any type of customer gas service order or call, including all premises odor calls, tests of the subsurface atmosphere must be made using gas detection equipment, except as noted below. At least one test must be made at a location where the buried service line or yard line is near the structure; for copper service lines, at least one (1) additional test must be made at the customer's property line, approximately one hundred feet (100') from the structure, or at the service tap at the main, whichever is closest to the structure. In lieu of conducting the tests of the subsurface atmosphere, the operator may conduct a leak survey of this pipe with gas detection equipment capable of detecting gas concentrations of three hundred (300) parts per million, gas-in-air. These tests are not required for collections, discontinuance of service for nonpayment, meter readings, read-ins/read-outs, line locations, atmospheric corrosion protection work or general painting, when relighting after emergency outages or curtailments, when lighting customer pilot lights, cathodic protection work, or if leak tests have been conducted at the location within the previous fifteen (15) months.

(C) Leak Classifications. The leak classifications in this subsection apply to pipelines, and do not apply to fuel lines. The definitions for "pipeline," "fuel line," "reading," "sustained reading," "building," "tunnel," and "vault or manhole" are included in subsection (1)(B). The definition for "reading" is the highest sustained reading when testing in a bar hole or opening without induced ventilation. Thus, the leak classification examples involving a gas reading do not apply to outside pipelines located aboveground. Even though the leak classifications do not apply to fuel lines, an operator must respond immediately to each notice of an inside leak or odor as required in paragraphs (12)(J)1., (14)(B)1., and (14)(B)2. In addition, the requirements in paragraph (12)(S)3. apply to fuel lines that are determined to be unsafe.

1. Class 1 leak is a gas leak which, due to its location and/or magnitude, constitutes an immediate hazard to a building and/or the general public. A Class 1 leak requires immediate corrective action. Examples of Class 1 leaks are: a gas fire, flash, or explosion; broken gas facilities such as contractor damage, main failures or blowing gas in a populated area; an indication of gas present in a building emanating from operator-owned facilities; a gas reading equal to or above the lower explosive limit in a tunnel, sanitary sewer, or confined area; gas entering a building or in imminent danger of doing so; and any leak which, in the judgment of the supervisor at the scene, is regarded as immediately hazardous to the public and/or property. When venting at or near the leak is the immediate corrective action taken for Class 1 leaks where gas is detected entering a building, the leak may be reclassified to a Class 2 leak if the gas is no longer entering the building, nor is in imminent danger of doing so. However, the leak shall be rechecked daily and repaired within fifteen (15) days. Leaks of this nature, if not repaired within five (5) days, may need to be reported as a safety-related condition, as required in 20 CSR 4240-40.020(12) and (13). (191.23 and 191.25)

2. Class 2 leak is a leak that does not constitute an immediate hazard to a building or to the general public, but is of a nature requiring action as soon as possible. The leak of this classification must be rechecked every fifteen (15) days, until repaired, to determine that no immediate hazard exists. A Class 2 leak may be properly reclassified to a lower leak classification within fifteen (15) days after the initial investigation. Class 2 leaks due to readings in sanitary sewers, tunnels, or confined areas must be repaired or properly reclassified within fifteen (15) days after the initial investigation. All other Class 2 leaks must be eliminated within forty-five (45) days after the initial investigation, unless it is definitely included and scheduled in a rehabilitation or replacement program to be completed within a period of one (1) year, in which case the leak must be rechecked every fifteen (15) days to determine that no immediate hazard exists. Examples of Class 2 leaks are: a leak from a transmission line discernible twenty-five feet (25') or more from the line and within one hundred feet (100') of a building; any reading outside a building at the foundation or within five feet (5') of the foundation; any reading greater than fifty percent (50%) gas-in-air located five to fifteen feet (5'–15') from a building; any reading below the lower explosive limit in a tunnel, sanitary sewer, or confined area; any reading equal to or above the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 leak, which in the judgment of the supervisor at the scene, is regarded as requiring Class 2 leak priority.

3. Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine action. These leaks must be repaired within five (5) years and be rechecked twice per calendar year, not to exceed six and one-half (6 1/2) months, until repaired or the facility is replaced. Examples of Class 3 leaks are: any reading of fifty percent (50%) or less gas-in-air located between five and fifteen feet (5'–15') from a building; any reading located between fifteen and fifty feet (15'–50') from a building, except those defined in Class 4; a reading less than the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 or Class 2 which, in the judgment of the supervisor at the scene, is regarded as requiring Class 3 priority.

4. Class 4 leak is a confined or localized leak which is completely nonhazardous. No further action is necessary.

(15) Replacement Programs.

(A) Scope. This section prescribes minimum requirements for the establishment of replacement programs for certain pipelines.

(B) Replacement Programs—General Requirements. Each operator shall establish written programs to implement the requirements of this section. The requirements of this section apply to pipelines as they existed on December 15, 1989.

(C) Replacement Program—Unprotected Steel Service Lines and Yard Lines. At a minimum, each investor-owned, municipal, or master meter operator shall establish instrument leak detection survey and replacement programs for unprotected operator-owned and customer-owned steel service lines and yard lines. The operator may choose from the following options, unless otherwise ordered by the commission:

1. Conduct annual instrument leak detection surveys on all unprotected steel service lines and yard lines and implement a replacement program where all unprotected steel service lines and yard lines will be replaced by May 1, 1994;

2. Conduct annual instrument leak detection surveys on all unprotected steel service lines and unprotected steel yard lines. The operator shall compile a historical summary listing the cumulative number of unprotected steel service lines and yard lines installed, replaced, or repaired due to underground leakage and with active underground leaks in a defined area. Based on the results of the summary, the operator shall initiate replacement, to be completed within eighteen (18) months, of all unprotected steel service lines and yard lines in a defined area once twenty-five percent (25%) or more meet the previously mentioned repair, replacement, and leakage conditions. At a minimum, ten percent (10%) of the customer-owned unprotected steel service lines in the system as of December 15, 1989, must be replaced annually. Beginning with calendar year 1994, a minimum of five percent (5%) of the unprotected steel yard lines, and operator-owned and installed unprotected steel service lines in the system as of December 15, 1989, must be replaced annually; and

3. Conduct annual instrument leak detection surveys on all unprotected steel service lines and unprotected steel yard lines and implement a replacement program. The program must prioritize replacements based on the greatest potential for hazards. At a minimum, ten percent (10%) of the customer-owned unprotected steel service lines in the system as of December 15, 1989, must be replaced annually. Beginning with calendar year 1994, a minimum of five percent (5%) of the unprotected steel yard lines, and operator-owned and installed unprotected steel service lines in the system as of December 15, 1989, must be replaced annually.

(D) Replacement Program — Cast Iron.

1. Operators who have cast iron transmission lines, feeder lines, or mains shall develop a replacement program to be submitted with an explanation to the commission by May 1, 1990, for commission review and approval. This systematic replacement program shall be prioritized to identify and eliminate pipelines in those areas that present the greatest potential for hazard in an expedited manner. These high priority replacement areas would include, but not be limited to:

A. High-pressure cast iron pipelines located beneath pavement which is continuous to building walls;

B. High-pressure cast iron pipelines located near concentrations of the general public such as Class 4 locations, business districts and schools;

C. Small diameter cast iron pipelines;

D. Areas where extensive excavation, blasting or construction activities have occurred in close proximity to cast iron pipelines;

E. Sections of cast iron pipeline that have had sections replaced as a result of requirements in subsection (13)(Z) (192.755);

F. Sections of cast iron pipeline that lie in areas of planned future development projects, such as city, county, or state highway construction/relocations, urban renewal, etc.; and

G. Sections of cast iron pipeline that exhibit a history of leakage or graphitization.

2. A long-term, organized replacement program and schedule shall also be established for cast iron pipelines not identified by the operator as being high priority.

3. Operators who have cast iron service lines shall replace them by December 31, 1991.

(E) Replacement/Cathodic Protection Program — Unprotected Steel Transmission Lines, Feeder Lines, and Mains. Operators who have unprotected steel transmission lines, feeder lines, or mains shall develop a program to be submitted with an explanation to the commission by May 1, 1990, for commission review and approval. This program shall be prioritized to identify and cathodically protect or replace pipelines in those areas that present the greatest potential for hazard in an expedited manner. These high priority areas should include, but not be limited to:

1. High-pressure unprotected steel pipelines located beneath pavement which is continuous to building walls;

2. High-pressure unprotected steel pipelines near concentrations of the general public such as Class 4 locations, business districts, and schools;

3. Areas where extensive excavation, blasting, or construction activities have occurred in close proximity to unprotected steel pipelines;

4. Sections of unprotected steel pipeline that lie in areas of planned future development projects, such as city, county, or state highway construction/relocations, urban renewal, etc.;

5. Sections of unprotected steel pipeline that exhibit a history of leakage or corrosion; and

6. Sections of unprotected steel pipeline subject to stray current.

(16) Pipeline Integrity Management for Transmission Lines.

(A) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2021, and the subsequent amendments 192-130 (published in *Federal Register* on April 8, 2022, page 87 FR 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, 2021, version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. The *Federal Registe*r publication on page 87 FR 20940 is available at 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.

(C) Subpart O and appendices E and F to 49 CFR part 192 contain the federal regulations regarding pipeline integrity management for transmission lines. Subpart O includes sections 192.901 through 192.951. Information regarding subpart O is available at http://primis.phmsa.dot.gov/gasimp.

(D) When sending a notification or filing a report with PHMSA in accordance with this section, a copy must also be submitted concurrently to designated commission personnel.

This is consistent with the requirement in 20 CSR 4240-40.020(5)(A) for reports to PHMSA.

(E) In 49 CFR 192.911(m) and (n), the references to "A State or local pipeline safety authority when the covered segment is located in a State where OPS has an interstate agent agreement" do not apply to Missouri and are replaced with "designated commission personnel." As a result, the communication plan required by 49 CFR 192.911(m) must include procedures for addressing safety concerns raised by designated commission personnel and the procedures required by 49 CFR 192.911(n) must address providing a copy of the operator's risk analysis or integrity management program to designated commission personnel.

(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. 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.

6. In 49 CFR 192.917, 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.

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

17. 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.

30. In 49 CFR 192.935, 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.

33. In 49 CFR 192.935, 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.

35. In 49 CFR 192.941, the reference to "section 192.706" should refer to "20 CSR 4240-40.030(13)(D)" instead.

36. In 49 CFR 192.945, the references to "section 191.17 of this subchapter" should refer to "20 CSR 4240-40.020(10)" instead.

37. In 49 CFR 192.947, 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.

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.

(17) Gas Distribution Pipeline Integrity Management (IM).

(A) What Definitions Apply to this Section? (192.1001) The following definitions apply to this section.

1. Excavation damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection, or the housing for the line device or facility.

2. Hazardous leak means a Class 1 leak as defined in paragraph (14)(C)1.

3. Integrity management plan or IM plan means a written explanation of the mechanisms or procedures the operator will use to implement its integrity management program and to ensure compliance with this section.

4. Integrity management program or IM program means an overall approach by an operator to ensure the integrity of its gas distribution system.

5. Mechanical fitting means a mechanical device used to connect sections of pipe. The term ''Mechanical fitting'' applies

only to—

A. Stab Type fittings;

B. Nut Follower Type fittings;

C. Bolted Type fittings; or

D. Other Compression Type fittings.

(B) What Do the Regulations in this Section Cover? (192.1003)

1. General. Unless exempted in paragraph (17)(B)2., this section prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this rule, including liquefied petroleum gas systems. A gas distribution operator must follow the requirements in section (17).

2. Exceptions. Section (17) does not apply to—

A. Individual service lines directly connected to a production line or a gathering line other than a regulated onshore gathering line as determined in subsection (1)(E) of this rule (192.8);

B. Individual service lines directly connected to either a transmission or regulated gathering pipeline and maintained in accordance with paragraphs (13)(BB)1. and 2. of this rule (192.740(a) and (b)); and

C. Master meter systems.

(C) What Must a Gas Distribution Operator (Other than a Small LPG Operator) Do to Implement this Section? (192.1005) No later than August 2, 2011, a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in subsection (17)(D).

(D) What Are the Required Elements of an Integrity Management Plan? (192.1007) A written integrity management plan must contain procedures for developing and implementing the following elements:

1. Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

A. Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

B. Consider the information gained from past design, operations, and maintenance.

C. Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (e.g., design, construction, operations, or maintenance activities).

D. Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

E. Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed;

2. Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other issues that could threaten the integrity of its pipeline. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience;

3. Evaluate and rank risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services, and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk;

4. Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found);

5. Measure performance, monitor results, and evaluate effectiveness.

A. Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(I) Number of hazardous leaks either eliminated or repaired as required by paragraph (14)(C)1. (or total number of leaks if all leaks are repaired when found), categorized by cause;

(II) Number of excavation damages;

(III) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(IV) Total number of leaks either eliminated or repaired, categorized by cause;

(V) Number of hazardous leaks either eliminated or repaired as required by paragraph (14)(C)1. (or total number of leaks if all leaks are repaired when found), categorized by material; and

(VI) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat;

6. Periodic evaluation and improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one (1) location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five (5) years. The operator must consider the results of the performance monitoring in these evaluations; and

7. Report results. Report, on an annual basis, the four (4) measures listed in parts (17)(D)5.A.(I)–(IV), as part of the annual report required by 20 CSR 4240-40.020(7)(A). An operator also must report the four (4) measures to designated commission personnel.

(E) *(Reserved)*

(F) What Records Must an Operator Keep? (192.1011) An operator must maintain records demonstrating compliance with the requirements of this section for at least ten (10) years. The records must include copies of superseded integrity management plans developed under this section.

(G) When May an Operator Deviate from Required Periodic Inspections Under this Rule? (192.1013)

1. An operator may propose to reduce the frequency of

periodic inspections and tests required in this rule on the basis of the engineering analysis and risk assessment required by this section.

2. An operator must submit its written proposal to the secretary of the commission. The commission may accept the proposal on its own authority, with or without conditions and limitations as the commission deems appropriate, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

3. An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

(H) What Must a Small LPG Operator Do to Implement this Section? (192.1015)

1. General. No later than August 2, 2011, the small LPG operator must develop and implement an IM program that includes a written IM plan as specified in paragraph (17)(G)2. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

2. Elements. A written integrity management plan must address, at a minimum, the following elements:

A. Knowledge. The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (e.g., design, construction, operations, or maintenance activities);

B. Identify threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation;

C. Rank risks. The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat;

D. Identify and implement measures to mitigate risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline;

E. Measure performance, monitor results, and evaluate effectiveness. The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes; and

F. Periodic evaluation and improvement. The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five (5) years. The operator must consider the results of the performance monitoring in these evaluations.

3. Records. The operator must maintain, for a period of at least ten (10) years, the following records:

A. A written IM plan in accordance with this subsection, including superseded IM plans;

B. Documents supporting threat identification; and

C. Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

(18) Waivers of Compliance. Upon written request to the secretary of the commission, the commission, by authority order and under such terms and conditions as the commission deems appropriate, may waive in whole or part compliance with any of the requirements contained in this rule. Waivers will be granted only on a showing that gas safety is not compromised. If the waiver request would waive compliance with a federal requirement in 49 CFR part 192, additional actions shall be taken in accordance with 49 USC 60118 except when the provisions of subsection (17)(G) apply.

Appendix A — 20 CSR 4240-40.030
(Reserved)

Appendix B to 20 CSR 4240-40.030
Appendix B — Qualification of Pipe and Components

I. List of Specifications.
A. Listed Pipe Specifications.

ANSI/API Specification 5L — Steel pipe, "API Specification for Line Pipe" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A53/A53M — Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A106/A106M — Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A333/A333M — Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A381 — Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A671/A671M — Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A672/A672M — Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A691/A691M — Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513 — "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F2817–10 — ''Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

B. Other Listed Specifications for Components.

ASME B16.40–2008 — "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513 — "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1055–98 (2006) — "Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1924–12 — "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1948–12 — "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing" (incorporated by reference, in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1973–13 — "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F2817–10 — "Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

II. Steel pipe of unknown or unlisted specification.

A. Bending properties. For pipe two inches (2") (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least ninety degrees (90º) around a cylindrical mandrel that has a diameter twelve (12) times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld. For pipe more than two inches (2") (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53/A53M (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), except that the number of tests must be at least equal to the minimum required in paragraph II.D. of this appendix to determine yield strength.

B. Weldability. A girth weld must be made in the pipe by a welder who is qualified under section (5) of 20 CSR 4240-40.030. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than four inches (4") (102 millimeters) in diameter, at least one (1) test weld must be made for each one hundred (100) lengths of pipe. On pipe four inches (4") (102 millimeters) or less in diameter, at least one (1) test weld must be made for each four hundred (400) lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the *ASME Boiler and Pressure Vessel Code* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). The same number of chemical tests must be made as are required for testing a girth weld.

C. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. Tensile properties. If the tensile properties of the pipe are not known, the minimum yield strength may be taken as twenty-four thousand (24,000) psi (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)). All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests – All Sizes

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in paragraph (2)(C)3. of 20 CSR 4240-40.030. (192.55[c])

III. Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications. Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I. of this appendix, is qualified for use under this rule if the following requirements are met:

A. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe; and

B. Similarity of specification requirements. The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I. of this appendix:

1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation and yield to tensile ratio, and testing requirements to verify those properties; and

2) Chemical properties of pipe and testing requirements to verify those properties; and

C. Inspection or test of welded pipe. On pipe with welded seams, one (1) of the following requirements must be met:

1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I. of this appendix; or

2) The pipe must be tested in accordance with section (10) of 20 CSR 4240-40.030 to at least one and one-fourth (1.25) times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least one and one-half (1.5) times the maximum allowable operating pressure if it is to be installed in a Class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under section (10) of 20 CSR

4240-40.030, the test pressure must be maintained for at least eight (8) hours.

Appendix C to 20 CSR 4240-40.030
Appendix C — Qualification of Welders for Low Stress Level Pipe

I. Basic test. The test is made on pipe twelve inches (12") (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one (1) section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four (4) coupons and subjected to a root bend test. If, as a result of this test, two (2) or more of the four (4) coupons develop a crack in the weld material, or between the weld material and base metal, that is more than one-eighth inch (1/8") (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. A welder who successfully passes a butt-weld qualification test under this section shall be qualified to weld on all pipe diameters less than or equal to twelve inches (12").

II. Additional tests for welders of service line connections to mains. A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. Periodic tests for welders of small service lines. Two (2) samples of the welder's work, each about eight inches (8") (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of two inches (2") (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable; and

2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in paragraph III.1) of this appendix.

Appendix D to 20 CSR 4240-40.030
Appendix D — Criteria for Cathodic Protection and Determination of Measurements

I. Criteria for cathodic protection.

A. Steel, cast iron, and ductile iron structures.

1) A negative (cathodic) polarized voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made in accordance with sections II. and IV. of this appendix.

2) A minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

3) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV. of this appendix.

4) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. Aluminum structures.

1) Except as provided in I.B.3) and 4) of this appendix, a minimum negative (cathodic) voltage shift of one hundred fifty (150) millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II. and IV. of this appendix.

2) Except as provided in paragraphs I.B.3) and 4) of this appendix, a minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

3) Notwithstanding the alternative minimum criteria in paragraphs I.B.1) and 2) of this appendix, aluminum, if cathodically protected at voltages in excess of one and two-tenths (1.20) volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV. of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the buildup of alkalis on the metal surface. A voltage in excess of one and two-tenths (1.20) volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

4) Because aluminum may suffer from corrosion under high pH conditions and because application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of eight (8).

C. Copper structures. A minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

D. Metals of different anodic potentials. A negative (cathodic) voltage, measured in accordance with section IV. of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs I.B.3) and 4) of this appendix, they must be electrically isolated with insulating flanges or the equivalent.

II. Interpretation of voltage measurement. Voltage (IR) drops other than those across the structure-electrolyte boundary must be adequately compensated for in order to obtain a valid interpretation of the voltage measurement in paragraphs I.A.1) and I.B.1) of this appendix. Possible methods of compensating for IR drops include:

1) Determining the cathodic voltage immediately upon interruption of the protective current; or

2) If interruption of the protective current is impractical for galvanic systems, the voltage measurements must be obtained at locations where the influence of potential gradients from nearby sacrificial anodes is minimized.

III. Determination of polarization voltage shift. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in I.A.2), I.B.2), and I.C. of this appendix.

IV. Reference half cells.

A. Except as provided in paragraphs IV.B. and IV.C. of this appendix, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two (2) commonly used reference half cells are listed here along with their voltage equivalent to – 0.85 volt as referred to a saturated copper-copper sulfate half cell:

1) Saturated KCl calomel half cell: – 0.78 volt; and

2) Silver-silver chloride half cell used in sea water: – 0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

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

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20 CSR 4240-40.030(7) General Construction Requirements for Transmission Lines and Mains

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(E) Repair of Steel Pipe. (192.309)
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(Q) Manual Service Line Shut-Off Valve Installation. (192.385)
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20 CSR 4240-40.030(9) Requirements for Corrosion Control

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(F) External Corrosion Control — Inspection of Buried Pipeline When Exposed. (192.459)
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(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)
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(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)
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(C) Procedural Manual for Operations, Maintenance, and Emergencies. (192.605)
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(E) Verification of Pipeline Material Properties and Attributes: Steel Transmission Pipelines. (192.607)
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(L) Investigation of Failures and Incidents. (192.617)
(M) Maximum Allowable Operating Pressure—Steel or Plastic Pipelines. (192.619 and 192.620)
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(U) Maximum Allowable Operating Pressure Reconfirmation: Steel Transmission Pipelines. (192.624)
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(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

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(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)
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(K) Transmission Lines—Testing of Repairs. (192.719)
(L) Distribution Systems—Patrolling. (192.721)
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(N) Test Requirements for Reinstating Service Lines and Fuel Lines. (192.725)
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(Y) Caulked Bell and Spigot Joints. (192.753)
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(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)
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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. Amended: Filed Dec. 28,* *1970, effective Jan. 6, 1971. Amended: Filed Dec. 29, 1971, effective Jan. 7, 1972. Amended: Filed Feb. 16, 1973, effective Feb. 26, 1973. Amended: Filed Feb. 1, 1974, effective Feb. 11, 1974. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Emergency amendment filed Jan. 17, 1977, effective Jan. 27, 1977, expired May 27, 1977. Amended: Filed Jan. 17, 1977, effective June 1, 1977. Emergency amendment filed March 15, 1978, effective March 25, 1978, expired July 23, 1978. Amended: Filed March 15, 1978, effective July 13, 1978. Amended: Filed July 5, 1978, effective Oct. 12, 1978. Amended: Filed July 13, 1978, effective Oct. 12, 1978. Amended: Filed Jan. 12, 1979, effective April 12, 1979. Amended: Filed May 27, 1981, effective Nov. 15, 1981. Amended: Filed Dec. 28, 1981, effective July 15, 1982. Amended: Filed Jan. 25, 1983, effective June 16, 1983. Amended: Filed Jan. 17, 1984, effective June 15, 1984. Amended: Filed Nov. 16, 1984, effective April 15, 1985. Amended: Filed Jan. 22, 1986, effective July 18, 1986. Amended: Filed May 4, 1987, effective July 24, 1987. Amended: Filed Feb. 2, 1988, effective April 28, 1988. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Dec. 14, 2000, effective May 30, 2001. Amended: Filed Oct. 15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May 30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019. Amended: Filed Dec. 12, 2019, effective July 30, 2020. Amended: Filed June 29, 2021, effective Jan. 30, 2022. Amended: Filed July 29, 2022, effective Feb. 28, 2023. Amended: Filed July 27, 2023, effective March 30, 2024.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

***Fields v. Missouri Power & Light Company**, 374 SW2d 17 (Mo. 1963). Violations of general law, municipal ordinances, rules of the Public Service Commission and the like are considered and held to be negligence per se. Here, violation of a rule of a private gas company filed with the P.S.C. cannot result in the creation of a cause of action in favor of another person separate and apart from an action based on common law negligence.*

20 CSR 4240-40.033 Safety Standards–Liquefied Natural Gas Facilities

PURPOSE: This rule prescribes safety standards for liquefied natural gas (LNG) facilities used in the transportation of gas by pipeline that is subject to the pipeline safety standards in 20 CSR 4240-40.030. This rule adopts the federal regulations on this subject matter that apply to operators of liquefied natural gas facilities used in the transportation of gas by pipeline that is subject to the federal pipeline safety laws and pipeline safety standards.

PUBLISHER'S NOTE: The secretary of state has determined that the publication of the entire text of the material which is incorporated by reference as a portion of this rule would be unduly cumbersome or expensive. This material as incorporated by reference in this rule shall be maintained by the agency at its headquarters and shall be made available to the public for inspection and copying at no more than the actual cost of reproduction. This note applies only to the reference material. The entire text of the rule is printed here.

(1) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2018, 49 CFR part 193 is incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR part 193. 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, 2018 version of 49 CFR part 193 is available at www.gpo.gov/fdsys/search/showcitation.action.

(2) The commission adopts the federal pipeline safety regulations for liquefied natural gas facilities, 49 CFR part 193, as rules of the commission.

(3) For purposes of this rule, the following substitutions should be made for certain references in the federal pipeline safety regulations adopted by reference in section (2) of this rule:

(A) The references to "state agency" in sections 193.2017, 193.2019, and 193.2515 of 49 CFR part 193 should refer to "the commission" instead;

(B) The reference to "state procedures" in section 193.2017 should refer to "commission procedures" instead;

(C) The reference in 49 CFR 193.2011 to "Part 191 of this subchapter" for reporting of incidents, safety-related conditions, and annual pipeline summary data for LNG plants or facilities should refer to 20 CSR 4240-40.020 instead;

(D) The reference in 49 CFR 193.2605 to "Part 191.23 of this subchapter" for reporting requirements for safety related conditions should refer to 20 CSR 4240-40.020(12) instead;

(E) The reference in 49 CFR 193.2001 to "Part 192 of this chapter" for applicability of the standards should refer to 20 CSR 4240-40.030 instead;

(F) The reference in 49 CFR 193.2629 to "section 192.461 of this chapter" for protective coatings should refer to 20 CSR 4240-40.030(9)(G) instead; and

(G) The references in 49 CFR 193.2629 and 193.2635 to "section 192.463 of this chapter" for cathodic protection should refer to 20 CSR 4240-40.030(9)(H) instead.

(4) The federal pipeline safety regulations for liquefied natural gas (49 CFR part 193) adopted in section (2) of this rule contain subparts on general, siting requirements, design, construction, equipment, operations, maintenance, personnel qualifications and training, fire protection, and security.

(A) The general subpart contains sections on: scope, applicability, definitions, Department of Transportation (DOT) rules of regulatory construction reporting, documents incorporated by reference, plans and procedures, and mobile and temporary liquefied natural gas facilities.

(B) The siting requirements subpart contains sections on: scope, thermal radiation protection, flammable vapor-gas dispersion protection, and wind forces.

(C) The design subpart contains sections on: scope, material records, structural requirements for impoundment systems, dikes, covered systems, water removal and impoundment capacity, and requirements pertaining to nonmetallic membrane liners in storage tanks.

(D) The construction subpart contains sections on: scope, construction acceptance, corrosion control, and nondestructive tests for welds.

(E) The equipment subpart contains sections on: scope, control center, and sources of power.

(F) The operations subpart contains sections on: scope, operating procedures, cooldown, monitoring operations, emergency procedures, personnel safety, transfer procedures, investigations of failures, purging, communication systems, and operating records.

(G) The maintenance subpart contains sections on: scope, general, maintenance procedures, foreign material, support systems, fire protection, auxiliary power sources, isolating and purging, repairs, control systems, testing transfer hoses, inspecting storage tanks, corrosion protection, atmospheric corrosion control, external corrosion control, internal corrosion control, interference currents, monitoring corrosion control, remedial measures, and maintenance records.

(H) The personnel qualifications and training subpart contains sections on: scope, design and fabrication, construction, installation, inspection and testing, operations and maintenance, security, personnel health, operations and maintenance training, security training, fire protection training, and records training.

(I) The fire protection subpart contains a section on fire protection.

(J) The security subpart contains sections on: scope, security procedures, protective enclosures, protective enclosure construction, security communications, security lighting, security monitoring, alternative power sources, and warning signs.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.033. Emergency rule filed Dec. 19, 2018, effective Dec. 29, 2018, expired June 26, 2019. Original rule filed Dec. 20, 2018, effective July 30, 2019. Moved to 20 CSR 4240-40.033, effective Aug. 28, 2019. Amended: Filed Dec. 12, 2019, effective July 30, 2020.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.040 Uniform System of Accounts — Gas Corporations

PURPOSE: This rule directs gas companies within the commission's jurisdiction to use the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for major natural gas companies, as modified herein. Requirements regarding the submission of depreciation studies, databases and property unit catalogs are found at 4 CSR 240-3.235 and 4 CSR 240-3.275.

(1) Beginning January 1, 1994, every gas company subject to the commission's jurisdiction shall keep all accounts in conformity with the Uniform System of Accounts Pre-scribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, as prescribed by the Federal Energy Regulatory Commission (FERC) and published at 18 CFR part 201 (1992) and 2 FERC Stat. & Regs. paragraph 20,001 and following (1992), except as otherwise provided in this rule. This uniform system of accounts provides instruction for recording financial information about gas corporations. It contains definitions; general instructions; gas plant instructions; operating expense instructions; accounts that comprise the balance sheet, gas plant, income, operating revenues, and operation and maintenance expenses.

(2) When implementing 4 CSR 240-40.040(1), each gas company subject to the commission's jurisdiction shall —

(A) Keep its accounts in the manner and detail specified for natural gas companies classified as "major" at Part 201 General Instructions 1.A. and paragraph 20,011.1.A.; and

(B) Assemble by July 1, 1996 and maintain after that, a property unit catalog which contains for each designated property unit, in addition to the provisions of Part 201 General Instructions 6. and paragraph 20,016 —

1. A description of each unit;
2. An item list; and
3. Accounting instructions, including instructions for distinguishing between operations expense, maintenance expense and capitalized plant improvements.

(3) Regarding plant acquired or placed in service after 1993, when implementing section (1), each gas corporation subject to the commission's jurisdiction shall —

(A) Maintain plant records of the year of each unit's retirement as part of the "continuing plant inventory records," as the term is otherwise defined at Part 201 Definitions 8. and paragraph 20,001.8.;

(B) State the detailed gas plant accounts (301 to 399, inclusive) on the basis of original cost, estimated if not known, when implementing the provisions of Part 201 Gas Plant Instructions 1.C. and paragraph 20,041.1.C.;

(C) Record gas plant acquired as an operating unit or system at original cost, estimated if not known, except as otherwise provided by the text of the intangible plant accounts, when implementing the provisions of Part 201 Gas Plant Instructions 2.A. and paragraph 20,042.2.A.;

(D) Account for the cost of items not classified as units of property as it would account for the cost of individual items of equipment of small value or of short life, as provided in Part 201 Gas Plant Instructions 3.A.(3) and paragraph 20,043.3.A.(3);

(E) Include in equipment accounts any hand or other portable tools which are specifically designated as units of property, when implementing the provisions of Part 201 Gas Plant Instructions 9.B. and paragraph 20,049.9.B.;

(F) Use the list of retirement units contained in its property unit catalog when implementing the provisions of Part 201 Gas Plant Instructions 10.A. and paragraph 20,050.10.A.;

(G) Estimate original cost with an appropriate average of the original cost of the units by vintage year, with due allowance for any difference in size and character, when it is impracticable to determine the original cost of each unit, when implementing the provisions of Part 201 Gas Plant Instructions 10.D. and paragraph 20,050.10.D.;

(H) Charge original cost less net salvage to account 108., when implementing the provisions of Part 201 Gas Plant Instructions 10.F. and paragraph 20,050.10.F.;

(I) Keep its work order system so as to show the nature of each addition to or retirement of gas plant by vintage year, in addition to the other requirements of Part 201 Gas Plant Instructions 11.B. and paragraph 20,051.11.B.;

(J) Maintain records which classify, for each plant account, the amounts of the annual additions and retirements so as to show the number and cost of the various record units or retirement units by vintage year, when implementing the provisions of Part 201 Gas Plant Instructions 11.C. and paragraph 20,051.11.C.;

(K) Maintain subsidiary records which separate account 108. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Account 108.C. and paragraph 20,011.108.C.;

(L) Maintain subsidiary records which separate account 111. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Accounts 111.C. and paragraph 20,114.111.C.; and

(M) Keep mortality records of property and property retirement as will reflect the average life of retiring property and will aid actuarial analysis of the probable service life of annual additions and aged retirements when implementing the provisions of Part 201 Income Accounts 403.B. and paragraph 20,422.403.B.

(4) In prescribing this system of accounts the commission does not commit itself to the approval or acceptance of any item set out in any account, for the purpose of fixing rates or in determining other matters before the commission. This rule shall not be construed as waiving any recordkeeping requirement in effect prior to 1994.

(5) The commission may waive or grant a variance from the provisions of this rule, in whole or in part, for good cause shown, upon a utility's written application.

AUTHORITY: sections 386.250 and 393.140, RSMo 2000. This rule originally filed as 4 CSR 240-40.040. Original rule filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed April 26, 1976, effective Sept. 11, 1976. Amended: Filed Feb. 5, 1993, effective Oct. 10, 1993. Amended: Filed March 19, 1996, effective Oct. 30, 1996. Amended: Filed Aug. 16, 2002, effective April 30, 2003. Moved to 20 CSR 4240-40.040, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.080 Drug and Alcohol Testing

PURPOSE: This rule adopts the federal regulations on this subject matter that apply to operators of gas systems. The rule requires operators of gas systems to test certain employees for the presence of prohibited drugs or alcohol and provide an employee assistance program. In addition, the rule provides a description of the technical procedures which must be utilized in conducting the drug and alcohol testing. The rule applies to operators of gas systems subject to the safety jurisdiction of the Public Service Commission.

PUBLISHER'S NOTE: The secretary of state has determined that the publication of the entire text of the material which is incorporated by reference as a portion of this rule would be unduly cumbersome or expensive. This material as incorporated by reference in this rule shall be maintained by the agency at its headquarters and shall be made available to the public for inspection and copying at no more than the actual cost of reproduction. This note applies only to the reference material. The entire text of the rule is printed here.

(1) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2019, 49 CFR parts 40 and 199 are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR parts 40 and 199. 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, 2019, version of 49 CFR parts 40 and 199 is available at https://www.govinfo.gov/#citation.

(2) The commission adopts the federal pipeline safety regulations for drug and alcohol testing, 49 CFR part 199, as rules of the commission.

(3) The commission adopts the federal procedures for transportation workplace drug and alcohol testing programs, 49 CFR part 40, as rules of the commission.

(4) For purposes of this rule, the following substitutions should be made for certain references in the federal pipeline safety regulations adopted by reference in section (2) of this rule:

(A) The references to "state agency" in sections 199.3, 199.101, 199.107, 199.115, 199.117, 199.231, and 199.245 of 49 CFR part 199 should refer to "the commission" instead;

(B) The references to "accident" in sections 199.3, 199.100, 199.105, 199.200, 199.221, 199.225, 199.227, and 199.231 of 49 CFR part 199 should refer to a "federal incident reportable under 20 CSR 4240-40.020" instead;

(C) The references to "part 192, 193, or 195 of this chapter" or "part 192, 193, or 195" in sections 199.1, 199.3, 199.100, and 199.200 of 49 CFR part 199 should refer to "20 CSR 4240-40.030 or 40.033" instead (the commission regulations contained in 20 CSR 4240-40.030 parallel 49 CFR part 192, and 20 CSR 4240-40.033 adopts 49 CFR part 193, but the commission does not have any rules pertaining to 49 CFR part 195); and

(D) The references to the applicability exemptions for operators of master meter systems as defined in section "191.3 of this chapter" in 49 CFR 199.2 should refer to "20 CSR 4240-40.020(2)(G)" instead.

(5) The federal pipeline safety regulations for drug and alcohol testing (49 CFR part 199) adopted in section (2) of this rule contain subparts on general, drug testing, and alcohol misuse prevention program.

(A) The general subpart contains sections on: scope, applicability, definitions, Department of Transportation (DOT) procedures, stand-down waivers, and preemption of state and local laws.

(B) The drug testing subpart contains sections on: purpose; anti-drug plan; use of persons who fail or refuse a drug test; drug tests required; drug testing laboratory; review of drug testing results; employee assistance program; contractor employees; record keeping; and reporting of anti-drug testing results.

(C) The alcohol misuse prevention program subpart contains sections on: purpose; alcohol misuse plan; other requirements imposed by operators; requirement for notice; alcohol concentration; on-duty use; pre-duty use; use following an accident; refusal to submit to a required alcohol test; alcohol tests required; retention of records; reporting of alcohol testing results; access to facilities and records; removal from covered function; required evaluation and testing; other alcohol-related conduct; operator obligation to promulgate a policy on the misuse of alcohol; training for supervisors; referral, evaluation, and treatment; and contractor employees.

(6) The federal procedures for transportation workplace drug and alcohol testing programs (49 CFR part 40) adopted by reference in section (3) of this rule contain subparts on administrative provisions; employer responsibilities; urine collection personnel; collection sites, forms, equipment, and supplies used in DOT urine collections; urine specimen collections; drug testing laboratories; medical review officers and the verification process; split specimen tests; problems in drug tests; alcohol testing personnel; testing sites, forms, equipment, and supplies used in alcohol testing; alcohol screening tests; alcohol confirmation tests; problems in alcohol testing; substance abuse professionals and the return-to-duty process; confidentiality and release of information; roles and responsibilities of service agents; and public interest exclusions.

*AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016.**

This rule originally filed as 4 CSR 240-40.080. Original rule filed Nov. 29, 1989, effective April 2, 1990. Rescinded and readopted: Filed Jan. 9, 1996, effective Aug. 30, 1996. Rescinded and readopted: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Oct. 15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May 30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019. Moved to 20 CSR 4240-40.080, effective Aug. 28, 2019. Amended: Filed Dec. 12, 2019, effective July 30, 2020. Amended: Filed June 29, 2021, effective Jan. 30, 2022.

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.085 Filing Requirements for Gas Utility Rate Schedules

PURPOSE: This rule streamlines provisions formerly in Chapter 3.

(1) Every gas corporation engaged in the manufacture, furnishing, or distribution of gas of any nature whatsoever for light, heat, or power, within the state of Missouri, is directed to have on file with this commission and keep open for public inspection, schedules showing all rates and charges in connection with such service of whatever nature made by the gas corporations for each and every kind of service which it renders together with proper supplements covering all changes in the rate schedules authorized by this commission if any.

(2) Rate schedules shall be published on the gas corporation's website. All sheets, except the title page sheet, must show in the marginal space at the top of the page the name of the gas corporation issuing, the PSC number of schedule, and the number of the page. In the marginal space at the bottom of sheet should be shown the date of issue, the effective date, and the name, title, and address of the officer by whom the schedule is issued. All schedules shall bear a number with the prefix PSC Mo. ______. Schedules shall be numbered in consecutive order beginning with number 1 for each gas corporation. If a schedule or part of a schedule is cancelled, a new schedule or part thereof (sheet(s) if loose-leaf) will refer to the schedule canceled by its PSC number; thus: PSC Mo. No. __ canceling PSC Mo. No. __ .

(3) All schedules filed with the commission shall be accompanied by a letter of transmittal which shall be prepared consistent with the format designated by the commission. If filing a paper copy and a paper receipt is desired, a duplicate copy should be submitted for return.

(4) All proposed changes in rates, charges, or rentals or in rules that affects rates, charges, or rentals filed with the commission shall be accompanied by a brief summary, approximately one hundred (100) words or less of the effect of the change on the company's customers. A copy of any proposed change and summary shall also be served on the public counsel and be available for public inspection and reproduction during regular office hours at the general business office of the utility.

(5) Thirty (30) days' notice to the commission is required as to every publication relating to gas rates or service except where publications are made effective on less than statutory notice by permission, rule, or requirement of the commission.

(6) Except as is otherwise provided, no schedule or supplement will be accepted for filing unless it is delivered to the commission via the Electronic Filing and Information System (EFIS), or if filing a paper copy, by transmiting or hand-delivering one (1) copy of each rate schedule, supplement, or other charges or regulations to the commission. Schedules sent for filing must be addressed to: Public Service Commission, PO Box 360, Jefferson City, MO 65102 and be free from all charges or claims for postage, the full thirty (30) days required by law before the date upon which the schedule or supplement is stated to be effective. No consideration will be given to or for the time during which a schedule or supplement may be held by the post office authorities because of insufficient postage. When a schedule or a supplement is issued and as to which the commission is not given the statutory notice, it is as if it had not been issued and a full statutory notice must be given of any reissuance. In those cases the schedule will be returned to the sender and correction of the neglect or omission cannot be made which takes into account any time elapsing between the date upon which the schedule or supplement was received and the date of the attempted correction. For rate schedules and supplements issued on short notice under special permission of the commission, literal compliance with the requirements for notice named in any order, rule, or permission granted by the commission will be exacted.

AUTHORITY: sections 386.250 and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.085. Original rule filed Nov. 28, 2018, effective July 30, 2019. Moved to 20 CSR 4240-40.085, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996 and 393.140, RSMo 1939, amended 1949, 1967.*

20 CSR 4240-40.090 Submission Requirements for Gas Utility Depreciation Studies

PURPOSE: This rule streamlines provisions from rules formerly in Chapter 3.

(1) Each gas utility subject to the commission's jurisdiction shall submit a depreciation study, database, and property unit catalog to the manager of the commission's engineering analysis unit and to the Office of the Public Counsel, as required by the terms of subsection (l)(B).

(A) The depreciation study, database, and property unit catalog shall be compiled as follows:

1. The study shall reflect the average life and remaining life of each primary plant account or subaccount;

2. The database shall consist of dollar amounts, by plant account or subaccount, representing—

A. Annual dollar additions and dollar retirements by vintage year and year retired, beginning with the earliest year of available data;

B. Reserve for depreciation;

C. Surviving plant balance as of the study date; and

D. Estimated date of final retirement and surviving dollar investment for each warehouse, propane/air production facility, liquefied natural gas facility, underground natural gas storage facility, general office building, or other large structure; and

3. The property unit catalog shall contain a description of

each retirement unit used by the utility.

(B) A gas utility shall submit its depreciation study, database, and property unit catalog on the following occasions:

1. Upon the date five (5) years from the last time the commission's staff received a depreciation study, database, and property unit catalog from the utility; and

2. Upon submission of a general rate increase request. However, a gas utility need not submit a depreciation study, database, or property unit catalog to the extent that the commission's staff received these items from the utility during the three (3) years prior to the utility's filing for a general rate increase request.

AUTHORITY: section 386.250, RSMo 2016. This rule originally filed as 4 CSR 240-40.090. Original rule filed Nov. 28, 2018, effective July 30, 2019. Moved to 20 CSR 4240-40.090, effective Aug. 28, 2019.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996.*

20 CSR 4240-40.100 Renewable Natural Gas Program

PURPOSE: This rule sets the definitions, structure, operation, and procedures relevant to gas corporations' renewable natural gas programs.

(1) Definitions.

(A) Energy attribute certificate means a contractual instrument that conveys information about a unit of energy, including the resource used to create the energy and the emissions associated with its production and use.

(B) Pipeline quality standards are standards established in 20 CSR 4240-10.030 Standards of Quality and are applicable to gas utilities submitting applications for approval of a renewable natural gas program.

(C) Renewable natural gas (RNG) means any of the following products processed to meet pipeline quality standards or transportation fuel grade requirements:

1. Biogas that is upgraded to meet natural gas pipeline quality standards such that it may blend with, or substitute for, geologic natural gas; or

2. Hydrogen gas that is derived from electrolysis of water using renewable electricity; or

3. Methane gas derived from any combination of—

A. Biogas;

B. Hydrogen gas or carbon oxides derived from renewable energy sources; or

C. Waste carbon dioxide.

(D) Renewable natural gas rate adjustment mechanism (RNGRAM) means a mechanism that allows periodic adjustments to recover prudently incurred capital costs, depreciation expense, and applicable taxes and pass-through of benefits of any savings achieved in implementing an approved RNG program.

(E) RNG Attributes means an energy attribute certificate specific to RNG which provides a monetary value besides the value of the natural gas itself.

(2) Applications for approval of a renewable natural gas program. Pursuant to section 386.895, RSMo, a gas corporation may file an application with the commission for approval of a renewable natural gas program. Applications under this rule do not supersede a gas utility's obligation to apply for a certificate of convenience and necessity under section 393.170, RSMo. Applications shall include all applicable requirements under 20 CSR 4240-2.060 and the following:

(A) A proposal to procure a total volume of renewable natural gas over a specific period;

(B) Identification of the qualified investments that the gas corporation may make in renewable natural gas infrastructure;

(C) A description of the ownership structure of the components of the RNG production facilities including but not limited to feed-stock, production, gas treatment, interconnection facilities, by-product, and other components as applicable by facility type;

(D) An explanation of how the utility will match generation with customer usage, be it on a retrospective or percentage basis;

(E) The specific location of the RNG facilities in relation to the utility's service territory;

(F) Expected production by calendar month;

(G) A description of the RNG plant operation;

(H) All prospective income tax credits;

(I) All prospective sales of RNG attributes;

(J) Supportive direct testimony; and

(K) A cost-benefit analysis, including but not limited to—

1. Reasonably estimated upfront capital costs, broken down by the components referenced in subsection (2)(C) of this rule;

2. Reasonably estimated future capital costs;

3. Reasonably estimated operations and maintenance expenses;

4. If applicable, ongoing costs of procuring RNG or RNG attributes from the facility;

5. Expected useful life of facility components;

6. All supporting work papers with links and formulas intact;

7. A list and explanation of all assumptions utilized;

8. Support for all assumptions utilized, including source documentation;

9. Consideration of the timing of RNG production, including estimates of the amount of RNG produced by month, for the life of the proposed project;

10. Plans and costs to store produced RNG;

11. Estimated cost of procuring the same volume of natural gas from a pipeline, including estimates of the price per million British thermal units (MMBtu) by month for the life of the proposed RNG project; and

12. All alternatives considered for procuring RNG or RNG attributes.

(3) Hydrogen gas programs, for safety and fuel quality reasons, will be evaluated on a case-by-case basis. All proposed hydrogen gas programs must include the requirements in section (2) and—

(A) Description of the impacted service area;

(B) Feasibility analysis;

(C) Analysis of customer-owned equipment and piping to safely convey hydrogen;

(D) Proposed percentage of hydrogen to be mixed in fuel; and

(E) All relevant information to a customer bill that accounts for the differences in heat content of hydrogen compared to natural gas measured in British thermal units (Btu) per hundred cubic feet (Ccf) of fuel.

(4) Cost recovery and pass-through of benefits. A gas utility outside or in a general rate proceeding, and subsequent to or at

the same time as the filing of an application in section (2), may file an application and rate schedules with the commission to establish, continue, modify, or discontinue a RNGRAM that shall allow for the adjustment of its rates and charges to provide for recovery of prudently incurred capital costs, depreciation expense, and applicable taxes and pass-through of benefits as a result of its RNG program or hydrogen gas program. No recovery is allowed until the project is operational and produces RNG for customer use.

(A) At the time a gas utility files proposed rate schedules with the commission seeking to establish, modify, or reconcile a RNGRAM, it shall submit its supporting documentation regarding the calculation of the proposed RNGRAM and shall serve the Office of the Public Counsel (public counsel) with a copy of its proposed rate schedules and its supporting documentation. The utility's supporting documentation shall include workpapers showing the calculation of the proposed RNGRAM and shall include, at a minimum, the following information:

1. A complete explanation of all of the costs, both capital and expense, incurred for its RNG program that the gas utility is proposing be included in rates and all revenues and the specific account used for each item;

2. The state, federal, and local income or excise tax rates used in calculating the proposed RNGRAM and an explanation of the source of and the basis for using those tax rates;

3. The regulatory capital structure used in calculating the proposed RNGRAM and an explanation of the source of and the basis for using the capital structure;

4. The cost rates for debt and preferred stock used in calculating the proposed RNGRAM and an explanation of the source of and the basis for using those rates;

5. The cost of common equity used in calculating the proposed RNGRAM and an explanation of the source of and the basis for that equity cost;

6. The depreciation rates used in calculating the proposed RNGRAM and an explanation of the source of and the basis for using those depreciation rates;

7. The rate base used in calculating the proposed RNGRAM including an updated depreciation reserve total incorporating the impact of all RNG plant investments previously reflected in general rate proceedings or RNGRAM application proceedings initiated following enactment of the RNG rules;

8. The applicable customer class billing methodology used in calculating the proposed RNGRAM and an explanation of the source of and basis for using that methodology;

9. An explanation of how the proposed RNGRAM is allocated among affected customer classes, if applicable;

10. For purchase of RNG attributes, the cost of the purchases, and an explanation of the source of the RNG attributes and the basis for making that specific purchase, including an explanation of the request for proposal (RFP) process, or the reason(s) for not using a RFP process for the purchase; and

11. Evidence that projects developed pursuant to its approved RNG program are operational and capable of delivering RNG to customers.

(B) A gas utility may effectuate a change in its RNGRAM no more often than one (1) time during any calendar year.

(C) Commission approval of proposed rate schedules to establish or modify a RNGRAM shall in no way be binding upon the commission in determining the ratemaking treatment to be applied to RNG program costs during a subsequent general rate proceeding or prudence review when the commission may undertake to review the prudence of such costs. If the commission disallows, during a subsequent general rate proceeding or prudence review, recovery of RNG program costs previously in a RNGRAM, the gas utility shall offset its RNGRAM in the future as necessary to recognize and account for any such disallowed costs. The offset amount shall include a calculation of interest at the gas utility's short-term borrowing rate as calculated in paragraph (4)(D)1. of this rule. The RNGRAM offset will be designed to reconcile such disallowed costs or benefits within the six- (6-) month period immediately subsequent to any commission order regarding such disallowance.

(D) Prudence reviews respecting a RNGRAM. A prudence review of the costs subject to the RNGRAM shall be conducted no less frequently than once a year, unless the commission orders otherwise during a proceeding in which the RNGRAM is established.

1. All amounts ordered refunded by the commission shall include interest at the gas utility's short-term borrowing rate. The interest shall be calculated on a monthly basis for each month the RNGRAM rate is in effect, equal to the weighted average interest rate paid by the gas utility on short-term debt for that calendar month.

2. This rate shall then be applied to a simple average of the same month's beginning and ending cumulative RNGRAM over- or under-collection balance. Each month's accumulated interest shall be included in the RNGRAM over- or under-collection balances on an ongoing basis.

(E) A gas utility that has implemented a RNGRAM shall file revised RNGRAM rate schedules to reset the RNGRAM charge to zero (0) when new base rates and charges become effective following a commission order establishing customer rates in a general rate proceeding that incorporates RNG program costs or benefits previously reflected in a RNGRAM in the utility's base rates. If an over- or under-recovery of RNGRAM revenues or over- or under-pass-through of RNGRAM program benefits exists after the RNGRAM charge has been reset to zero (0) that amount of over- or under-recovery, or over- or under-pass-through, shall be tracked in an account and considered in the next RNGRAM filing of the gas utility.

(F) Upon the inclusion of RNGRAM program costs reflected in a RNGRAM into a gas utility's base rates, the gas utility shall immediately thereafter reconcile any previously unreconciled RNGRAM revenues or RNGRAM benefits and track them as necessary to ensure that revenues or pass-through benefits resulting from the RNGRAM match, as closely as possible, the appropriate pretax revenues or pass-through benefits as found by the commission for that period.

(G) The cost of RNG or hydrogen gas shall not flow through the purchased gas adjustment clause unless the cost for the RNG or hydrogen gas, including RNG infrastructure, can be obtained on a comparable basis as natural gas purchased at the city gate of the utility. Amounts collected under the RNGRAM will not be collected though the purchased gas adjustment clause.

(5) Treatment and reporting of RNG attributes. A gas utility may propose, through the application in section (2) of this rule, to procure, utilize, or sell RNG attributes as a part of its RNG program provided that—

(A) All attributes are tracked in a commission-approved tracking system that ensures that attributes are tracked from creation to retirement and are verified to be only used once; and

(B) All costs and all revenues are passed through to customers as provided for in section (4) of this rule or through a general rate proceeding.

(6) Reporting requirements. Annually, on September 15, a gas utility with an approved RNG program shall report to the commission the following:

(A) A comparison of the total volume of RNG procured over the year compared to its approved RNG program;

(B) To the extent any shortfalls or excess RNG were procured, the gas utility shall describe how it plans to adjust its procurements to match the approved total volume; and

(C) Identification of the qualified investments previously approved through the application in section (2) of this rule that the gas corporation has made operational including all evidence to support that the qualified investments are operational and are capable of delivering gas to customers.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016, and section 386.895, RSMo Supp. 2024. Original rule filed May 15, 2024, effective Dec. 30, 2024.

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1939, amended 1979, 1989, 1996; 386.895, RSMo 2021; and 393.140, RSMo 1939, amended 1949, 1967.*