(4) Plats, maps, preliminary subdivision plans, drawings, reports, descriptions, surveys, or other technical submissions will be deemed to have been prepared under the immediate personal supervision of a professional land surveyor when the following circumstances exist*[—]***:**

(A) The **licensee, or an employee of the licensee's corporation, firm, partnership, association, or other entity authorized to do business, shall be in direct contact with the** client requesting preparation of plats, maps, preliminary subdivision plans, drawings, reports, descriptions, surveys, or other technical submissions *[makes the request directly to the professional land surveyor or an employee of the professional land surveyor, so long as the employee is employed directly under the professional land surveyor's organizational structure]*;

(C) The professional land surveyor is not employed by the client, solely for the purpose of reviewing and approving plats, maps, preliminary subdivision plans, drawings, reports, descriptions, surveys, or other technical submissions prepared by an unlicensed person, employee, or contractor of the client; *[and]*

(D) The professional land surveyor reviews the final plats, maps, preliminary subdivision plans, drawings, reports, descriptions, surveys, or other technical submissions and is able to, and does make, necessary and appropriate changes to them*[.]***; and**

(E) In circumstances where a licensee in responsible charge of the work is unavailable to complete the work, a successor licensee may take responsible charge by performing all professional services to include the development and preparation of plats, maps, preliminary subdivision plans, drawings, reports, descriptions, surveys, or other technical submissions. The non-professional services, such as drafting, need not be redone by the successor licensee but must clearly and accurately reflect the successor licensee's work. The burden is on the successor licensee to show such compliance. The successor licensee shall have control of and responsibility for the work product and the signed and sealed originals of all technical submissions.

AUTHORITY: section 327.041, RSMo 2016. This rule originally filed as 4 CSR 30-13.020. Original rule filed Dec. 16, 1988, effective Feb. 24, 1989. For intervening history, please consult the ***Code of State Regulations****. Amended: Filed June 21, 2021.*

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to this proposed amendment with the Missouri Board of Architects, Professional Engineers, Professional Land Surveyors, and Professional Landscape Architects, PO Box 184, Jefferson City, MO 65102, via facsimile at (573)751-8046, or via email at moapeplspla@pr.mo.gov. To be considered, comments must be received within thirty (30) days after publication of this notice in the ***Missouri Register****. No public hearing is scheduled.*

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

PROPOSED AMENDMENT

20 CSR 4240-40.020 Incident, Annual, and Safety-Related Condition Reporting Requirements. The commission is amending sections (2), (5), (6), and (9)–(13).

PURPOSE: This amendment modifies the rule to address amendments of 49 CFR part 191 promulgated between October 2019 and December 2020, and makes clarification and editorial changes.

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

(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 fifty thousand dollars ($50,000) 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 underground natural gas storage facility]* **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.;

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

1. A depleted hydrocarbon reservoir*[;]***,**

*[2. A]***a**n aquifer reservoir*[;]***,** or

*[3. A]***a** solution-mined *[salt]* cavern *[reservoir, including associated material and equipment used for]***; and**

2. In addition to the reservoir or cavern, a UNGNSF includes injection, withdrawal, monitoring, *[or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment]* **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**.

(5) Report Submission Requirements. (191.7)

(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 *[October 2014]* **April 2019**), gas transmission and gathering pipeline systems (PHMSA F 7100.2, revised *[October 2014]* **April 2019**), and LNG facilities (PHMSA F 7100.3, revised *[October 2014]* **April 2019**) are incorporated by reference in subsection (5)(G).

(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 *[April 2019]* **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 *[April*

2019] **January 2020** version.

B. U.S. Department of Transportation Form PHMSA F 1000.2, revised *[April 2019]* **January 2020**. The PHMSA F 1000.2 form is the *[Operator]* **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 *[April 2019]* **January 2020** version.

C. U.S. Department of Transportation Form PHMSA F 7100.1, revised *[October 2014]* **April 2019**. 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 *[October 2014]* **April 2019** version.

D. U.S. Department of Transportation Form PHMSA F 7100.1-1, revised October 2018. 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 October 2018 version.

E. U.S. Department of Transportation Form PHMSA F 7100.1-2, revised October 2014. The PHMSA F 7100.1-2 form is the report form for mechanical fitting failures and does not include any amendments or additions to the October 2014 version.

F. U.S. Department of Transportation Form PHMSA F 7100.2, revised *[October 2014]* **April 2019**. 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 *[October 2014]* **April 2019** version.

G. U.S. Department of Transportation Form PHMSA F 7100.2-1, revised October 2014. 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 October 2014 version.

H. U.S. Department of Transportation Form PHMSA F 7100.3, revised *[October 2014]* **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 *[October 2014]* **April 2019** version.

I. U.S. Department of Transportation Form PHMSA F 7100.3-1, revised August 2017. 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 August 2017 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.

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 *[October 2014]* **April 2019**) is incorporated by reference in subsection (5)(G).

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

(A) Transmission or Gathering. Each operator of a transmission or a 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 *[October 2014]* **April 2019**) 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 *[October 2014]* **April 2019**) is incorporated by reference in subsection (5)(G).

(C) Underground natural gas storage facility. Each operator of *[an underground natural gas storage facility]* **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). The incident report form (revised *[October 2014]* **April 2019**) is incorporated by reference in subsection (5)(G).

(D) Supplemental Report. *[When]* **Where** additional related information is obtained after **an operator submits** a report *[is submitted]* 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)

(C) Underground natural gas storage facility. Each operator of *[an underground natural gas storage facility]* **an UNGSF** must submit an annual report *[on]* **through** U.S. Department of Transportation Form PHMSA 7100.4-1**. This report must be submitted each year, no later than** *[by]* 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, *[underground natural gas storage 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 *[Pipeline and LNG]* Operators at *[http://portal.phmsa.dot.gov/pipeline]* **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 (*[April 2019]* **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 *[Pipeline and LNG]* Operators at *[http://opsweb.phmsa.dot.gov]* **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, *[underground natural gas storage facility]* **UNGSF,** LNG plant, or LNG facility must notify PHMSA electronically through the National Registry of *[Pipeline and LNG]* Operators at *[http://portal.phmsa.dot.gov/pipeline]* **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 *[or replacement]* pipeline;

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

D. *[Construction of a new underground natural gas storage facility or the abandonment, drilling, or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility]* **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, *[underground natural gas storage 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*[; or]*

[F. The acquisition or divestiture of an existing underground natural gas storage facility subject to 49 CFR Part 192].

(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 underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well]* **an UNGSF**, general corrosion that has reduced the wall thickness **of any metal component** to less than that required for the **well's** maximum *[well]* operating pressure, *[and]* **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 underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility]* **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 underground natural gas storage facility or]* **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 *[underground natural gas storage facility, including injection, withdrawal, monitoring, or observations well for an underground natural gas storage facility]* **an UNGSF**;

6. Any malfunction or operating error that causes the pressure *[of:]***, 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;**

[A. A pipeline to rise above its maximum allowable operating pressure plus the buildup allowed for operation of pressure limiting or control devices;

B. An underground natural gas storage facility to rise above its maximum well operating pressure plus the margin (build-up) allowed for operation of pressure limiting or control devices; or

C. An LNG facility that contains or processes gas or LNG to rise above its working pressure plus the margin (build-up) allowed for operation of pressure limiting or control devices.]

7. A leak in a pipeline *[or an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility]*, **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; *[and]*

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 *[or an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility]*, **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 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; *[or]*

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

*[4.]***5.** Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report*[, except that reports are required for conditions]***. Notwithstanding this exception, a report must be filed for—**

A. Conditions under paragraph (12)(A)1. *[other than]***, 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 *[subsection]* **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. *[See the report submission requirements in subsection (5)(C). Reports may be transmitted by electronic mail to InformationResourcesManager@dot.gov and PipelineSafetyProgramManager@psc.mo.gov. To file a report by telefacsimile (fax), dial (202) 366-7128 for the Office of Pipeline Safety and (573) 522-1946 for designated commission personnel]* **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).

*[(B)]***(C)** *[The report must be titled Safety-Related Condition Report and]* **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 *[and]***,** 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.

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. For intervening history, please consult the ***Code of State Regulations****. Amended: Filed June 29, 2021.*

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to the proposed amendment with the Missouri Public Service Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received no later than September 1, 2021, and should include a *reference to Commission Case No. GX-2021-0406. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing is scheduled for 10:00 a.m., September 7, 2021, in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment, and may be asked to respond to commission questions.*

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

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

PROPOSED AMENDMENT

20 CSR 4240-40.030 Safety Standards—Transportation of Gas by Pipeline. The commission is amending the purpose, sections (1)–(6), (9), (10), (12), (13), and (16), and Appendix E.

PURPOSE: This amendment modifies the rule to address amendments of 49 CFR part 192 promulgated between October 2019 and December 2020, and makes clarification and editorial changes.

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

(1) General.

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

1. Abandoned means permanently removed from service;

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

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

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

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

6. Commission means the Missouri Public Service Commission;

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

8. 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;

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

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

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

12. 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));

13. 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;

*[13.]***14.** 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);

*[14.]***15.** 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;

*[15.]***16.** Fuel line means the customer-owned gas piping downstream from the outlet of the customer meter or operator-owned pipeline, whichever is farther downstream;

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

*[17.]***18.** Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main;

*[18.]***19.** 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;

*[19.]***20.** 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;

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

*[21.]***22.** 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;

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

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

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

26. 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;

*[25.]***27.** Municipality means a city, village, or town;

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

*[27.]***29.** 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;

*[28.]***30.** 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);

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

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

*[31.]***33.** 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;

*[32.]***34**. 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;

*[33.]***35.** 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;

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

*[35.]***37.** 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;

*[36.]***38.** 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;

*[37.]***39.** 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]);

*[38.]***40.** 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;

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

*[40.]***42.** Transmission line means a pipeline, other than a gathering line, that—

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

B. Operates at a hoop stress of twenty percent (20%) or more of SMYS; or

C. Transports gas within a storage field;

*[41.]***43.** 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;

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

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

*[44.]***46.** 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;

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

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

*[47.]***49.** 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, 201*[8]***9**, and the subsequent amendment 192-*[124]***125** (published in *Federal Register* on *[November 20, 2018, page 84 FR 58694]* **October 1, 2019, page 84 FR 52180**), 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, 201*[8]***9** version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. The *Federal Register* publication on page *[83 FR 58694]* **84 FR 52180** is available at *[https://www.govinfo.gov/content/pkg/FR-2018-11-20/pdf/2018-24925.pdf]* **https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf**.

3. The regulation at 49 CFR 192.7 provides a listing of the documents that are incorporated by reference partly or wholly in 49

CFR part 192, which is the federal counterpart and foundation for this rule. All incorporated materials are available for inspection from several sources, including the following sources:

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

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

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

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

(E) Gathering Lines. (192.8 and 192.9)

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 201*[8]***9**, and the subsequent amendment 192-*[124]***125** (published in *Federal Register* on *[November 20, 2018, page 83 FR 58694]* **October 1, 2019, page 84 FR 52180**, the federal regulations at 49 CFR 192.8 and 192.9 are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR 192.8 and 192.9.

2. The *Code of Federal Regulations* is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 201*[8]***9** version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. The *Federal Register* publication on page *[83 FR 58694]* **84 FR 52180** is available at *[https://www.govinfo.gov/content/pkg/FR-2018-11-20/pdf/2018-24925.pdf]* **https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf**.

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

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

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

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

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

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

3. Unless otherwise specified, if the notification is made pursuant to (10)(K)2., (12)(E)5.D. and E., (12)(U)3.B.(III) and 3.F., (12)(V)2.C., (13)(DD)3.G., (13)(EE)4.C.(IV) and 5.B.(I)(e), 49 CFR 192.921(a)(7) (incorporated by reference in section (16)), or 49 CFR 192.937(c)(7) (incorporated by reference in section (16)) to use a different integrity assessment method, analytical method, sampling approach, or technique (i.e., "other technology") that differs from that prescribed in those requirements, the operator must notify PHMSA at least ninety (90) days in advance of using the "other technology." An operator may proceed to use the "other technology" ninety-one (91) days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of "other technology" or that PHMSA requires additional time to conduct its review.

(2) Materials.

(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.

*[(G)]***(H)** Storage and Handling of Plastic Pipe and Associated Components. (192.*[67]***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.

(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.

(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; and

G. 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.

(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.

(6) Joining of Materials Other Than by Welding.

(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]), or for polyethylene heat fusion joints (except for electrofusion joints) visually inspected and tested in accordance with ASTM F2620-12 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) 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.

(9) Requirements for Corrosion Control.

(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.

(10) Test Requirements.

(I) Records. (192.517)

1. For *[mains]* **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) *[and]***,** (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.

(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.

(12) Operations.

(E) *[(Reserved)]* **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 nonline 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 nonline 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)).

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

1. Except as provided in paragraph**s** (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], 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.

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);

Pipeline Segment	Pressure Date	Test date
Onshore gathering line that first became subject to 49 CFR 192.8 and 192.9 after April 13, 2006 (see subsection (1)(E)).	March 15, 2006, or date line becomes subject to this rule, whichever is later.	Five (5) years preceding applicable date in second column.
Onshore transmission line that was a gathering line not subject to 49 CFR 192.8 and 192.9 before March 15, 2006 (see subsection (1)(E)).	March 15, 2006	March 15, 2001
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, *[particularly]* **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). (192.195)

3. The requirements on pressure restrictions in this subsection do not apply in the following instance*[.]***:** An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 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).

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.

*[5.]***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.

(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 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 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 (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 (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.

(13) Maintenance.

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

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

A. A Class 3 or Class 4 location; or

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

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

2. General.

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

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

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

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

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

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

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

C. Spike hydrostatic pressure test. A spike hydrostatic pressure test conducted in accordance with subsection (10)(K). A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

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

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

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

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

4. Data analysis. An operator must analyze and account for the data obtained from an assessment performed under paragraph (13)(DD)3. to determine if a condition could adversely

affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

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

6. Remediation. An operator must comply with the requirements in subsections (9)(S), (13)(G), and (13)(H), 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. (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 section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)); R–STRENG (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

3. (Reserved)

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 section (1)(M) (192.18).

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. The technical approach used for the analysis;

B. All data used and analyzed;

C. Pipe and weld properties;

D. Procedures used;

E. Evaluation methodology used;

F. Models used;

G. Direct in situ examination data;

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

I. Pressure test data and results;

J. In-the-ditch assessments;

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

L. All finite element analysis results;

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

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

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

P. Reassessment time interval and safety factors;

Q. The date of the review;

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

S. Approval by responsible operator management personnel.

(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.

(16) Pipeline Integrity Management for Transmission Lines.

(A) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 201*[8]***9**, **and the subsequent amendment 192-125 (published in *Federal Register* on October 1, 2019, page 84 FR 52180),** the federal regulations in 49 CFR part 192, subpart O and in 49 CFR part 192, *[appendix]* **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 *[appendix]* **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, 201*[8]***9** version of 49 CFR part 192 is available at *[www.gpo.gov/fdsys/search/showcitation.action]* **https://www.govinfo.gov/#citation**. **The *Federal Register* publication on page 84 FR 52180 is available at https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf.**

(C) Subpart O and *[appendix]* **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.

(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 192.909(b), 192.921(a)(4), and 192.937(c)(4), the references to "a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State" should refer to "designated commission personnel" instead.]* **(Reserved)**

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

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

4. *[In 49 CFR 192.933(a)(1) and (2), the references to "a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State" should refer to "designated commission personnel" instead.]* **(Reserved)**

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

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

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

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

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

10. 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.

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*AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.030. Original rule filed Feb. 23, 1968, effective March 14, 1968. For intervening history, please consult the **Code of State Regulations**. Amended: Filed June 29, 2021.*

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to the proposed amendment with the Missouri Public Service Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received no later than September 1, 2021, and should include a *reference to Commission Case No. GX-2021-0406. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing is scheduled for 10:00 a.m., September 7, 2021, in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment, and may be asked to respond to commission questions.*

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.

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

PROPOSED AMENDMENT

20 CSR 4240-40.080 Drug and Alcohol Testing. The Commission is amending section (1) of this rule.

PURPOSE: This amendment modifies the rule to incorporate by reference the most recent version of 49 CFR parts 40 and 199.

(1) As set forth in the *Code of Federal Regulations* (CFR) dated

October 1, 201*[8]***9**, *[and the subsequent amendment published on April 23, 2019 (published in Federal Register on April 23, 2019, page 84 FR 16770),]* 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, 201*[8]***9**, version of 49 CFR parts 40 and 199 *[and the Federal Register publication on page 84 FR 16770 are]* **is** available at https://www.govinfo.gov/#citation.

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. For intervening history, please consult the ***Code of State Regulations****. Amended: Filed June 29, 2021.*

PUBLIC COST: This proposed amendment will not cost state agencies or political subdivisions more than five hundred dollars ($500) in the aggregate.

PRIVATE COST: This proposed amendment will not cost private entities more than five hundred dollars ($500) in the aggregate.

NOTICE OF PUBLIC HEARING AND NOTICE TO SUBMIT COMMENTS: Anyone may file a statement in support of or in opposition to the proposed amendment with the Missouri Public Service Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received no later than September 1, 2021, and should include a reference to Commission Case No. GX-2021-0406. Comments may also be submitted via a filing using the commission's electronic filing and information system at http://www.psc.mo.gov/efis.asp. A public hearing is scheduled for 10:00 a.m., September 7, 2021, in Room 310 of the Governor Office Building, 200 Madison St., Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed amendment, and may be asked to respond to commission questions.

SPECIAL NEEDS: Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 or TDD Hotline 1-800-829-7541.