recommendation to the commission advising whether the request should be granted.

(6) A utility subject to this rule that is unable to meet the submission date established in section (1) of this rule may obtain an extension of up to thirty (30) days for submitting its annual report by—
(A) Submitting a written request, which states the reason for the extension, to the attention of the secretary of the commission prior to April 15; and
(B) Certifying that a copy of the written request was sent to all parties of record in pending cases before the commission where the utility's activities are the primary focus of the proceedings.

(7) A utility subject to this rule that is unable to meet the submission date established in section (1) of this rule may request an extension of greater than thirty (30) days for submitting its annual report by—
(A) Filing a pleading, in compliance with the requirements of Chapter 2 of 4 CSR 240-2, which states the reason for and the length of the extension being requested, with the commission prior to April 15; and
(B) Certifying that a copy of the pleading was sent to all parties of record in pending cases before the commission where the utility's activities are the primary focus of the proceedings.

(8) Responses to deficiency notices under the provisions of section (3) of this rule, requests for confidential treatment under the provisions of section (4) of this rule, pleadings requesting public disclosure of information contained under seal under the provisions of section (5) of this rule, and requests for extensions of time under the provisions of sections (6) or (7) of this rule may be submitted through the commission's electronic filing and information system (EFIS).

(9) A utility subject to this rule that does not timely file its annual report, or its response to a notice that its annual report is deficient, is subject to a penalty of one hundred dollars ($100) and an additional penalty of one hundred dollars ($100) for each day that it is late in filing its annual report or its response to a notice of deficiency.

AUTHORITY: sections 386.250 and 393.140, RSMo 2016. Original rule filed June 14, 2018.

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

PRIVATE COST: This proposed rule 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 rule with the Missouri Public Service Commission, Morris L. Woodruff, Secretary of the Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received at the commission's offices on or before August 15, 2018, and should include a reference to Commission Case No. AX-2018-0257. 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 Wednesday, August 22, 2018 at 2:00 p.m., 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 rule, 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 4—DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

4 CSR 240-40.020 Incident, Annual, and Safety-Related Condition Reporting Requirements. The commission is amending sections (2), (3), (7), (11), (12), and (13).

PURPOSE: This amendment proposes to amend the rule to address the 2016 amendment of 49 CFR part 191, to correct errors and inadvertent omissions from previous amendments, and to remove unnecessary verbiage.

(2) Definitions. (191.3) As used in this rule and in the PHMSA Forms referenced in this rule—
(B) Commission means the Public Service Commission. Designated commission personnel means the Pipeline Safety Program Manager at the address contained in subsection (5)(E) for *[required]* correspondence and means the list of staff personnel supplied to operators for *[required]* telephonic notices;
(C) Confirmed discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation;
*[(C)]***(D)** Federal incident means any of the following events:
1. An event that involves a release of gas from a pipeline 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; or
2. An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph *[(2)(C)1.]* **(2)(D)1.**;
*[(D)]***(E)** Gas means natural gas, flammable gas, manufactured gas or gas which is toxic or corrosive;
*[(E)]***(F)** LNG **facility** means **a pipeline facility that is used for liquefying natural gas or synthetic gas or transferring, storing, or vaporizing** liquefied natural gas;
(G) LNG plant means an LNG facility or system of LNG facilities functioning as a unit;
*[(F)]***(H)** Master meter system means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, for instance, by rents;
*[(G)]***(I)** Municipality means a city, village, or town;
*[(H)]***(J)** Operator means a person who engages in the transportation of gas;
*[(I)]***(K)** Person means any individual, firm, joint venture, partnership, corporation, association, county, state, municipality, political subdivision, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative of them;
*[(J)]***(L)** Pipeline or pipeline system means all parts of those physical facilities through which gas moves in transportation including, but not limited to, pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies;

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

[(L)](**N**) Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce*[.]***; and**

(O) Underground natural gas storage facility means a facility that stores natural gas in an underground facility incident to natural gas transportation, including—

1. A depleted hydrocarbon reservoir;

2. An aquifer reservoir; or

3. A solution-mined salt cavern reservoir, including associated material and equipment used for injection, withdrawal, monitoring, or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment.

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

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

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

(7) Distribution System—Annual Report and Mechanical Fitting Failure Reports.

(A) Annual Report. (191.11)

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

2. The annual report form (revised *[May 2015]* **January 2017**) is incorporated by reference and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the *[May 2015]* **January 2017** version.

3. The annual report requirement in this subsection does not apply to a master meter system or to a petroleum gas system which serves fewer than one hundred (100) customers from a single source.

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

(A) OPID Request.

1. Effective January 1, 2012, each operator of a gas pipeline**,** *[or]* gas pipeline facility**, underground natural gas storage facility, LNG plant or LNG facility** must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline 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 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 (May 2015) is incorporated by reference and is published by U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001. The form is available at www.phmsa.dot.gov/pipeline/library/forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E). The form does not include any amendments or additions to the May 2015 version.

(C) Changes. Each operator of a gas pipeline**,** *[or]* gas pipeline facility**, underground natural gas storage facility, 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 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; *[or]*

B. Construction of ten (10) or more miles of a new **or replacement** pipeline*[.]***;**

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

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;

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 4 CSR 240-40.030(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, *[or]* pipeline facility**, underground natural gas storage facility, or LNG facility**; *[or]*

D. The acquisition or divestiture of fifty (50) or more miles of a pipeline or pipeline system subject to 4 CSR 240-40.030*[.]***;**

E. The acquisition or divestiture of an existing 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]* **a** 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. Unintended movement or abnormal loading by environmental causes, for instance, an earthquake, landslide**,** or flood, that impairs

the serviceability of a pipeline;

3. 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;

4. Any malfunction or operating error that causes the pressure of a pipeline to rise above its maximum allowable operating pressure plus the buildup allowed for operation of pressure limiting or control devices;

5. A leak in a pipeline that constitutes an emergency; and

6. 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.

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

(A) Each report of a safety-related condition under subsection (12)(A) must be filed (received by the Office of Pipeline Safety at PHMSA and designated commission personnel) 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 *[InformationResourceManager@dot.gov]* **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.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. Original rule filed Feb. 5, 1970, effective Feb. 26, 1970. For intervening history, please consult the ***Code of State Regulations****. Amended: Filed June 4, 2018.*

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 this proposed amendment with the Missouri Public Service Commission, Morris L. Woodruff, Secretary of the Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received at the commission's offices on or before August 15, 2018, and should include a reference to Commission Case No. GX-2018-0279. 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 August 20, 2018 at 10:00 a.m., 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 4—DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

4 CSR 240-40.030 Safety Standards—Transportation of Gas by Pipeline. The commission is amending sections (1), (3), (4), (5), (6), (7), (8), (9), (12), (13), (14), (15), and (17).

PURPOSE: This amendment modifies the rule to address amendments of 49 CFR part 192 promulgated between January 2016 and September 2017 and makes clarification and editorial changes.

(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 4 CSR 240-40.020(5)(E) for *[required]* 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. 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. 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. 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. Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;

17. Gathering line means a pipeline that transports gas from a

current production facility to a transmission line or main;

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

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

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

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

25. Municipality means a city, village, or town;

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

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

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

31. 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. 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. 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. Reading means the highest sustained reading when testing in a bar hole or opening without induced ventilation;

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

40. 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. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas in Missouri;

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

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

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

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

46. 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 *[shall]* mean**s** 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 *[shall]* **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 *[shall]* **will** be considered the yard line and any other lines are not considered yard lines.

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

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, *[2015]* **2017**, 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, *[2015]* **2017** version of 49 CFR part 192 is available at www.gpo.gov/fdsys/search/showcitation.action.

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, *[2015]* **2017**, 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, *[2015]* **2017** version of 49 CFR part 192 is available at www.gpo.gov/fdsys/search/showcitation.action.

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.

(F) Petroleum Gas Systems. (192.11)

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

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

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

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

1. Except as provided in paragraph *[(1)(H)3.]* **(1)(H)4.**, a steel pipeline previously used in service not subject to this rule qualifies for use under this rule if the operator prepares and follows a written procedure to carry out the following requirements:

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

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

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

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

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

3. An operator converting a pipeline from service not previously covered by this rule must notify PHMSA and designated commission personnel sixty (60) days before the conversion occurs as required by 4 CSR 240-40.020(11).

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

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

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

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

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

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

1. Each operator shall submit to designated commission personnel all plans, procedures, and programs required by this rule (to include welding and joining procedures, construction standards, control room management procedures, corrosion control procedures, damage prevention program, distribution integrity management plan, emergency procedures, public education program, operator qualification program, replacement programs, transmission integrity management program, and procedural manual for operations, maintenance, and emergencies). In addition, each change must be submitted to designated commission personnel within twenty (20) days after the change is made.

2. All operators under the pipeline safety jurisdiction of the Missouri Public Service Commission must establish and submit welding procedures, joining procedures, and construction specifications and standards to designated commission personnel before construction activities begin. All other plans, procedures and programs required by rules 4 CSR 240-40.020, 4 CSR 240-40.030, and 4 CSR 240-40.080 must be established and submitted to designated commission personnel before the system is put into operation.

3. A written plan for drug and alcohol testing in accordance with 4 CSR 240-40.080 must be submitted to designated commission personnel.

(L) Customer Notification**,** *[Required by]* Paragraph (12)(S)2. When providing gas service to a new customer or a customer relocated from a different operating district, *[the operator must provide the customer notification required by]* **see** paragraph (12)(S)2. **regarding applicable customer notification.**

(3) Pipe Design.

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

(4) Design of Pipeline Components.

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

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

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

$C = (3D \times P \times F)/1000$ **(in inches)**

($C=(3D \times P \times F)$ /*[2298]* **6,895**) **(in millimeters)**

where

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

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

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

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

(5) Welding of Steel in Pipelines.

(B) General. *[(192.223)]*

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

2. Welding *[must]* **is only to** be performed by welders who are

qualified under subsections (5)(D) and (E) (192.227 and 192.229) for the welding procedure to be used.

(C) Welding Procedures. (192.225)

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

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

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

1. Except as provided in paragraph (5)(D)2., each welder or welding operator must be qualified in accordance with section 6, section 12, *[or]* 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 than 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.

(6) Joining of Materials Other Than by Welding.

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

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

A. The burst test requirements of—

(I) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Pressure) *[or paragraph 8.9 (Sustained Static Pressure Test)]* of ASTM D2513-99 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for plastic materials other than polyethylene or ASTM D2513-09A (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)) for polyethylene plastic materials;

(II) *(Reserved)*; or

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

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

C. For procedures intended for nonlateral pipe connections, follow the tensile test requirements of ASTM D638 (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)), except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than twenty-five percent (25%) or failure initiates outside the joint area, the procedure qualifies for use.

2. Mechanical joints. Before any written procedure established under paragraph (6)(B)2. is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting five (5) specimen joints made according to the procedure to the following tensile test:

A. Use an apparatus for the test as specified in ASTM D638 (except for conditioning), (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D));

B. The specimen must be of such length that the distance between the grips of the apparatus and the end of the stiffener does not affect the joint strength;

C. The speed of testing is 0.20 inches (5.0 mm) per minute, plus or minus twenty-five percent (25%);

D. Pipe specimens less than four inches (4") (102 mm) in diameter are qualified if the pipe yields to an elongation of no less than twenty-five percent (25%) or failure initiates outside the joint area;

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

F. Each specimen that fails at the grips must be retested using new pipe; and

G. Results obtained pertain only to the specific outside diameter and material of the pipe tested, except that testing of a heavier wall pipe may be used to qualify pipe of the same material but with a lesser wall thickness.

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

4. Pipe or fittings manufactured before July 1, 1980 may be used in accordance with procedures that the manufacturer certifies will produce a joint as strong as the pipe.

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

(O) Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.328). The federal regulations at 49 CFR 192.328 are not adopted in this rule.

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

(O) Service Lines—Excess Flow Valve Performance Standards. (192.381)

1. Excess flow valves to be used on *[single residence]* service lines that operate continuously throughout the year at a pressure not less than ten (10) psi (69 kPa) must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will—

A. Function properly up to the maximum operating pressure at which the valve is rated;

B. Function properly at all temperatures reasonably expected in the operating environment of the service line;

C. At ten (10) psi (69 kPa) gauge:

(I) Close at, or not more than fifty percent (50%) above, the rated closure flow rate specified by the manufacturer; and

(II) Upon closure, reduce gas flow—

(a) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than five percent (5%) of the manufacturer's specified closure flow rate, up to a maximum of twenty (20) cubic feet per hour (0.57 cubic meters per hours); or

(b) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (0.01 cubic meters per hour); and

D. Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

2. An excess flow valve must meet the applicable requirements of sections (2) and (4).

3. An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

4. An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

5. An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service line, such as blowing liquids from the service line.

(P) Excess Flow Valve Installation. (192.383)

1. Definitions for subsection (8)(P).

A. Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

*[A.]***B.** Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

*[B.]***C.** Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one (1) single-family residence.

2. Installation required. An excess flow valve (EFV) installation must comply with the performance standards in subsection (8)(O). *[The operator must install an EFV on any new or replaced service line serving a single-family residence after February 12, 2010, unless one (1) or more of the following conditions is present]* **After April 14, 2017, each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated**:

A. A single service line to one single family residence;

B. A branched service line to a single family residence installed concurrently with the primary single family residence service line (i.e., a single EFV may be installed to protect both service lines);

C. A branched service line to a single family residence installed off a previously installed single family residence service line that does not contain an EFV;

D. Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation, based on installed meter capacity; and

E. A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.

3. Exceptions to excess flow valve installation requirement. An operator need not install an excess flow valve if one (1) or more of the following conditions are present:

A. The service line does not operate at a pressure of ten (10) psi gauge or greater throughout the year;

B. The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a residence;

C. An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

D. An EFV meeting performance standards in subsection (8)(O) is not commercially available to the operator.

4. Customer's right to request an EFV. Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one (1) of the exceptions in paragraph (8)(P)3. may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

5. Operator notification of customers concerning EFV installation. Operators must notify customers of their right to request an EFV in the following manner:

A. Except as specified in (8)(P)3. and (8)(P)5.E., each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, website postings, and e-billing notices.

B. The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks.

C. The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.

D. The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (8)(P)3. are not present, the operator must install an EFV at a mutually agreeable date.

E. Operators of master-meter systems may continuously post a general notification in a prominent location frequented by customers.

6. Operator evidence of customer notification. An operator must make a copy of the notice or notices currently in use available during inspections conducted by designated commission personnel.

*[3.]***7.** Reporting. **Except for operators of master meter systems,** *[E]*each operator must report the EFV measures detailed in the annual report required by 4 CSR 240-40.020(7)(A).

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

1. Definitions for subsection (8)(Q).

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

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

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

(9) Requirements for Corrosion Control.

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

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

2. Regulated onshore gathering lines. For any regulated onshore gathering line to which 49 CFR 192.8 and 192.9 did not apply until

April 14, 2006, and for any gathering line that becomes a regulated onshore gathering line under **subsection** (1)(E) because of a change in class location or increase in dwelling density:

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

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

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

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

2. Each cathodic protection rectifier or other impressed current power source must be inspected six (6) times each calendar year but with intervals not exceeding two and one-half (2 1/2) months to ensure that it is operating.

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

4. Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring *[required]* **set forth** in paragraphs (9)(I)1.–3. Corrective measures must be completed within six (6) months unless otherwise approved by designated commission personnel.

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

(12) Operations.

(B) General Provisions. (192.603)

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

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

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

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

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

1. General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines that are not exempt under subparagraph (12)(C)3.E., the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding fifteen (15) months, but at least once each calendar year. *[The manual must be revised, as necessary, within one (1) year of the effective date of revisions to this rule.]* This manual must be prepared before initial operations of a pipeline system commence and appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

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

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

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

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

D. Gathering of data needed for reporting incidents under 4 CSR 240-40.020 in a timely and effective manner;

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

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

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

H. Periodically reviewing the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found;

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

J. Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available, when needed at the excavation, emergency rescue equipment including a breathing apparatus and a rescue harness and line;

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

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

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

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

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

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

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

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

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

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

(I) Unintended closure of valves or shutdowns;

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

(III) Loss of communications;

(IV) Operation of any safety device; and

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

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

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

D. Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found; and

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

4. Safety-related conditions. The manual required by paragraph (12)(C)1. must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the commission's reporting requirements.

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

(D) Qualification of Pipeline Personnel.

1. Scope. (192.801)

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

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

(I) Is performed on a pipeline facility;

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

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

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

2. Definitions. (192.803)

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

(I) Indicate a condition exceeding design limits;

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

(III) Require an emergency response.

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

(I) Written examination;

(II) Oral examination;

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

(a) Performance on the job;

(b) On the job training; or

(c) Simulations.

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

(I) Perform assigned covered tasks; and

(II) Recognize and react to abnormal operating conditions.

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

A. Identify covered tasks;

B. Provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities;

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

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

*[D.]***E.** Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident meeting the Missouri reporting requirements in 4 CSR 240-40.020(4)(A);

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

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

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

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

*[I.]***J.** Ensure that covered tasks are—

(I) Performed by qualified individuals; or

(II) Directed and observed by qualified individuals; and

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

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

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

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

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

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

E. Recognize potential ignition sources;

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

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

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

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

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

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

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

A. Qualification records shall include:

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

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

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

(IV) Qualification method(s).

B. Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five (5) years.

9. General. (192.809)

A. *[Subsection (12)(D) for personnel qualification was promulgated in 1989, effective December 15, 1989. Operators were required to meet the training and testing requirements within eighteen (18) months following the effective date, or June 15, 1991. At that time, there were no federal requirements for personnel qualification.]* **Operators must have a written qualification program by April 27, 2001. The program must be available for review by designated commission personnel.**

B. *[Subpart N to 49 CFR 192 (Subpart N) was adopted with federal regulations for qualification of pipeline personnel, effective October 26, 1999. Subsection (12)(D) is being amended in 2000 to incorporate much of Subpart N, including all requirements in Subpart N that are more stringent than the original subsection (12)(D). However, subsection (12)(D) as amended is different from and more stringent than Subpart N, primarily because training and testing is still required and work performance history review is not permitted as an evaluation method. Operators should continue to comply with the original subsection (12)(D) until the following deadlines, which are from Subpart N.]* **Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.**

[(I) Operators must have a written qualification program by April 27, 2001. The program and any program changes must be submitted to designated commission personnel as required by subsection (1)(J).

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

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

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

(I) Damage Prevention Program. (192.614)

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

2. An operator may perform any of the duties *[required by]* **specified in** paragraph (12)(I)3. through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this subsection. However, an operator must perform the duties of subparagraph (12)(I)3.D. through participation in the qualified one-call system for Missouri. An operator's pipeline system must be covered by the qualified one-call system for Missouri.

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

A. Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located. A listing of persons involved in excavation activities shall be maintained and updated at least once each calendar year with intervals not exceeding fifteen (15) months. If an operator chooses to participate in an excavator education program of a one-call notification center, as provided for in subparagraphs (12)(I)3.B. and C., then such updated listing shall be provided to the one-call notification center prior to December 1 of each calendar year. This list should at least include, but not be limited to, the following:

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

(II) Telephone company;

(III) Electric utilities and co-ops;

(IV) Water and sewer utilities;

(V) City governments;

(VI) County governments;

(VII) Special road districts;

(VIII) Special water and sewer districts; and

(IX) Highway department district(s);

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

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

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

(II) Provide for at least semiannual educational mailings to the excavators named on the comprehensive listing maintained pursuant to part (12)(I)3.C.(I), by first class mail; and

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

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

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

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

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

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

F. If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings;

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

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

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

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

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

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

B. The proximity to the operator's facilities;

C. The type of excavating equipment involved;

D. The importance of the operator's facilities;

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

F. The potential for serious incident should damage occur;

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

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

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

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

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

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

7. Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

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

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

(S) Providing Service to Customers.

1. At the time an operator physically turns on the flow of gas to a customer (see requirements in subsection (10)(J) for new fuel line installations)—

A. Each segment of fuel line must be tested for leakage to at least the delivery pressure; and

B. A visual inspection of the exposed, accessible customer gas piping, interior and exterior, and all connected equipment shall be conducted to determine that the requirements of any applicable industry codes, standards, or procedures adopted by the operator to assure safe service are met. This visual inspection need not be met for emergency outages or curtailments. In the event a large commercial or industrial customer denies an operator access to the customer's premises, the operator does not need to comply with the above requirement if the operator obtains a signed statement from the customer stating that the customer will be responsible for inspecting its exposed, accessible gas piping, and all connected equipment, to determine that the piping and equipment meets any applicable codes, standards, or procedures adopted by the operator to assure safe service. In the event the customer denies an operator access to its premises and refuses to sign a statement as described above, the operator may file with the commission an application for waiver of compliance with this provision.

2. When providing gas service to a new customer or a customer relocated from a different operating district, the operator must provide the customer with the following as soon as possible, but within seven (7) calendar days, unless the operator can demonstrate that the information would be the same:

A. Information on how to contact the operator in the event of an emergency or to report a gas odor;

B. Information on how and when to contact the operator when excavation work is to be performed; and

C. Information concerning the customer's responsibility for maintaining his/her gas piping and utilization equipment. In addition, the operator should determine if a customer notification is *[required by]* **applicable per** subsection (1)(K).

3. The operator shall discontinue service to any customer whose fuel lines or gas utilization equipment are determined to be unsafe. The operator, however, may continue providing service to the customer if the unsafe conditions are removed or effectively eliminated.

4. A record of the test and inspection performed in accordance with this subsection shall be maintained by the operator for a period of not less than two (2) years.

(T) Control Room Management. (192.631)

1. General.

A. This subsection applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this subsection, except as follows. For each control room where an operator's activities are limited to either or both of distribution with less than two hundred fifty thousand (250,000) services or transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (12)(T)4. (regarding fatigue), (12)(T)9. (regarding compliance validation), and (12)(T)10. (regarding compliance and deviations).

B. The procedures required by this subsection must be integrated, as appropriate, with operating and emergency procedures required by subsections (12)(C) and (12)(J). An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraph (12)(T)2.; subparagraphs (12)(T)3.E. and (12)(T)4.B. and C.; and paragraphs (12)(T)6. and (12)(T)7. must be implemented no later than October 1, 2011. The procedures required by subparagraphs (12)(T)3.A.–D. and (12)(T)4.A. and D.; and paragraph (12)(T)5. must be implemented no later than August 1, 2012. The training procedures required by paragraph (12)(T)8. must be implemented no later than August 1, 2012, except that any training required by another paragraph or subparagraph of this subsection must be implemented no later than the deadline for that paragraph or subparagraph.

2. Roles and responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

A. A controller's authority and responsibility to make decisions and take actions during normal operations;

B. A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

C. A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others; *[and]*

D. A method of recording controller shift-changes and any hand-over of responsibility between controllers*[.]***; and**

E. The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

3. Provide adequate information. Each operator must provide its controllers with the information, tools, processes, and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

A. Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)) whenever a SCADA system is added, expanded, or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

B. Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

C. Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed fifteen (15) months;

D. Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed fifteen (15) months; and

E. Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

4. Fatigue mitigation. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

A. Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight (8) hours of continuous sleep;

B. Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

C. Train controllers and supervisors to recognize the effects of fatigue; and

D. Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

5. Alarm management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

A. Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

B. Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

C. Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed fifteen (15) months;

D. Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding fifteen (15) months, to determine the effectiveness of the plan;

E. Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed fifteen (15) months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

F. Address deficiencies identified through the implementation of subparagraphs (12)(T)5.A.–E.

6. Change management. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

A. Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;

B. Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and

C. Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

7. Operating experience. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

A. Review federal incidents that must be reported pursuant to 4 CSR 240-40.020 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to—

(I) Controller fatigue;
(II) Field equipment;
(III) The operation of any relief device;
(IV) Procedures;
(V) SCADA system configuration; and
(VI) SCADA system performance.

B. Include lessons learned from the operator's experience in the training program required by this subsection.

8. Training. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to

exceed fifteen (15) months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

A. Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

B. Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

C. Training controllers on their responsibilities for communication under the operator's emergency response procedures;

D. Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; *[and]*

E. For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application*[.]***; and**

F. Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal, or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.

9. Compliance validation. Operators must submit their procedures to designated commission personnel *[as required by]* **per** subsection (1)(J).

10. Compliance and deviations. An operator must maintain for review during inspection—

A. Records that demonstrate compliance with the requirements of this subsection; and

B. Documentation to demonstrate that any deviation from the procedures required by this subsection was necessary for the safe operation of a pipeline facility.

(13) Maintenance.

(F) Record Keeping. (192.709)

1. For transmission lines each operator shall keep records covering each leak discovered, repair made, line break, leakage survey, line patrol, and inspection for as long as the segment of transmission line involved remains in service. (192.709)

2. For feeder lines, mains, and service lines, each operator shall maintain—

A. Records pertaining to each original leak report for not less than six (6) years;

B. Records pertaining to each leak investigation and classification for not less than six (6) years. These records shall at least contain sufficient information to determine if proper assignment of the leak class was made, the promptness of actions taken, the address of the leak and the frequency of reevaluation and/or reclassification;

C. Records pertaining to each leak repair for the life of the facility involved, except no record is required for repairs of aboveground Class 4 leaks. These records shall at least contain sufficient information to determine the promptness of actions taken, address of the leak, pipe condition at the leak site, leak classification at the time of repair, and other such information necessary for proper completion of DOT annual Distribution and Transmission Line report forms (PHMSA F 7100.1-1 and PHMSA F 7100.2-1); **and**

D. Records pertaining to leakage surveys and line patrols conducted over each segment of pipeline for not less than six (6) years. These records shall at least contain sufficient information to determine the frequency, scope, and results of the leakage survey or line patrol*[; and]***.**

[E. Records pertaining to leak tests or surveys conducted in accordance with paragraph (14)(B)7. for not less than two (2) years.]

3. For yard lines and buried fuel lines, each operator shall maintain records of notifications and leakage surveys required by subsection (13)(M) for not less than six (6) years.

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

1. Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding fifteen (15) months but at least once each calendar year to inspections and tests to determine that it is—

A. In good mechanical condition;

B. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

C. Except as provided in paragraph (13)(R)2., set to control or relieve at the correct pressures that will prevent downstream pressures from exceeding the allowable pressures under subsections (4)(FF) and (12)(M)–(O);

D. Properly installed and protected from dirt, liquids, and other conditions that might prevent proper operation;

E. Properly protected from unauthorized operation of valves in accordance with paragraph (4)(EE)8.;

F. Equipped to indicate regulator malfunctions in accordance with paragraphs (4)(EE)10. and 11. in a manner that is adequate from the standpoint of reliability of operation; and

G. Equipped with adequate over-pressure protection in accordance with paragraph (4)(EE)9.

2. For steel pipelines whose MAOP is determined under paragraph (12)(M)3., if the MAOP is sixty (60) psi (four hundred fourteen (414) kPa) gauge or more, the control or relief pressure limit is as follows:

A. If the MAOP produces a hoop stress that is greater than seventy-two percent (72%) of SMYS, then the pressure limit is MAOP plus four percent (4%).

B. If the MAOP produces a hoop stress that is unknown as a percentage of SMYS, then the pressure limit is a pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

3. For individual service lines directly connected to production, gathering, or transmission pipelines, requirements for inspecting and testing devices and equipment are provided in subsection (13)(BB).

(Z) Protecting or Replacing Disturbed Cast Iron Pipelines. (192.755) When an operator has knowledge that the support for a segment of a buried cast iron pipeline is disturbed or that an excavation or erosion is nearby, the operator shall determine if more than half the pipe diameter lies within the area of affected soil. For the purposes of this subsection, "area of affected soil" *[shall]* refers to the area above a line drawn from the bottom of the excavation or erosion, at the side nearest the main, at a forty-five degree (45°) angle from the horizontal (a lesser angle should be used for sandy or loose soils, or a greater angle may be used for certain consolidated soils if the angle can be substantiated by the operator). If more than half the pipe diameter lies within the area of affected soil, the following measures/precautions must be taken—

1. That segment of the pipeline must be protected, as necessary, against damage during the disturbance by—

A. Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

B. Impact forces by vehicles;

C. Earth movement;

D. Water leaks or sewer failures that could remove or undermine pipe support;

E. Apparent future excavations near the pipeline; or

F. Other foreseeable outside forces which may subject that segment of the pipeline to bending stress;

2. If eight inches (8") or less in nominal diameter, then as soon as feasible, this segment of cast iron pipeline, which shall include a minimum of ten feet (10') beyond the area of affected soil, must be replaced, except as noted in paragraph (13)(Z)4.;

3. If greater than eight inches (8") in nominal diameter, then as

soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of subsection (7)(J) (192.319) and paragraph (7)(I)1. (192.317[a]); and

4. Replacement of cast iron pipelines would not necessarily be required if—

A. The support beneath the pipe is removed for a length less than ten (10) times the nominal pipe diameter not to exceed six feet (6');

B. For parallel excavations, the pipe lies within the area of affected soil for a length less than ten (10) times the nominal pipe diameter not to exceed six feet (6');

C. The excavation is made by the operator in the course of routine maintenance, such as leak repairs to the main or service line installation, where the exposed portion of the main does not exceed six feet (6'), and the backfill supporting the pipe is replaced and compacted by the operator; or

D. Permanent or temporary shoring was adequately installed to protect the cast iron pipeline during excavation and backfilling.

(BB) Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Production, Gathering, or Transmission Pipelines. (192.740)

1. This subsection applies, except as provided in paragraph (13)(BB)3., to any service line directly connected to a production, gathering, or transmission pipeline that is not operated as part of a distribution system.

2. Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every three (3) calendar years, not exceeding thirty-nine (39) months, to determine that it is:

A. In good mechanical condition;

B. Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

C. Set to control or relieve at the correct pressure consistent with the pressure limits of paragraph (4)(DD)2.; and to limit the pressure on the inlet of the service regulator to sixty (60) psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and

D. Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

3. This subsection does not apply to equipment installed on service lines that only serve engines that power irrigation pumps.

(14) Gas Leaks.

(C) Leak Classifications. The leak classifications in this subsection apply to pipelines, and do not apply to fuel lines. The definitions for "pipeline," "fuel line," "reading," "sustained reading," "building," "tunnel," and "vault or manhole" are included in subsection (1)(B). The definition for "reading" is the highest sustained reading when testing in a bar hole or opening without induced ventilation. Thus, the leak classification examples involving a gas reading do not apply to outside pipelines located aboveground. Even though the leak classifications do not apply to fuel lines, an operator must respond immediately to each notice of an inside leak or odor as required in paragraphs (12)(J)1., (14)(B)1., and (14)(B)2. In addition, the requirements in paragraph (12)(S)3. apply to fuel lines that are determined to be unsafe.

1. Class 1 leak is a gas leak which, due to its location and/or magnitude, constitutes an immediate hazard to a building and/or the general public. *[It shall require immediate corrective action which shall provide for public safety and protect property]* **A Class 1 leak requires immediate corrective action**. Examples of Class 1 leaks are: a gas fire, flash, or explosion; broken gas facilities such as contractor damage, main failures or blowing gas in a populated area; an indication of gas present in a building emanating from operator-owned facilities; a gas reading equal to or above the lower explosive limit in a tunnel, sanitary sewer, or confined area; gas entering a building or in imminent danger of doing so; and any leak which, in the judgment of the supervisor at the scene, is regarded as immediately hazardous to the public and/or property. When venting at or near the leak is the immediate corrective action taken for Class 1 leaks where gas is detected entering a building, the leak may be reclassified to a Class 2 leak if the gas is no longer entering the building, nor is in imminent danger of doing so. However, the leak shall be rechecked daily and repaired within fifteen (15) days. Leaks of this nature, if not repaired within five (5) days, may need to be reported as a safety-related condition, as required in 4 CSR 240-40.020(12) and (13). (191.23 and 191.25)

2. Class 2 leak is a leak that does not constitute an immediate hazard to a building or to the general public, but is of a nature requiring action as soon as possible. The leak of this classification must be rechecked every fifteen (15) days, until repaired, to determine that no immediate hazard exists. A Class 2 leak may be properly reclassified to a lower leak classification within fifteen (15) days after the initial investigation. Class 2 leaks due to readings in sanitary sewers, tunnels, or confined areas must be repaired or properly reclassified within fifteen (15) days after the initial investigation. All other Class 2 leaks must be eliminated within forty-five (45) days after the initial investigation, unless it is definitely included and scheduled in a rehabilitation or replacement program to be completed within a period of one (1) year, in which case the leak must be rechecked every fifteen (15) days to determine that no immediate hazard exists. Examples of Class 2 leaks are: a leak from a transmission line discernible twenty-five feet (25') or more from the line and within one hundred feet (100') of a building; any reading outside a building at the foundation or within five feet (5') of the foundation; any reading greater than fifty percent (50%) gas-in-air located five to fifteen feet (5'–15') from a building; any reading below the lower explosive limit in a tunnel, sanitary sewer, or confined area; any reading equal to or above the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 leak, which in the judgment of the supervisor at the scene, is regarded as requiring Class 2 leak priority.

3. Class 3 leak is a leak that does not constitute a hazard to property or to the general public but is of a nature requiring routine action. These leaks must be repaired within five (5) years and be rechecked twice per calendar year, not to exceed six and one-half (6 1/2) months, until repaired or the facility is replaced. Examples of Class 3 leaks are: any reading of fifty percent (50%) or less gas-in-air located between five and fifteen feet (5'–15') from a building; any reading located between fifteen and fifty feet (15'–50') from a building, except those defined in Class 4; a reading less than the lower explosive limit in a vault, catch basin, or manhole other than a sanitary sewer; or any leak, other than a Class 1 or Class 2 which, in the judgment of the supervisor at the scene, is regarded as requiring Class 3 priority.

4. Class 4 leak is a confined or localized leak which is completely nonhazardous. No further action is *[required]* **necessary**.

(15) Replacement Programs.

(B) Replacement Programs—General Requirements. Each operator shall establish written programs to implement the requirements of this section. The requirements of this section apply to pipelines as they existed on December 15, 1989. *[These programs shall be filed with designated commission personnel in accordance with subsection (1)(J) by May 1, 1990.]*

(C) Replacement Program—Unprotected Steel Service Lines and Yard Lines. At a minimum, each investor-owned, municipal, or master meter operator shall establish instrument leak detection survey and replacement programs for unprotected operator-owned and customer-owned steel service lines and yard lines. The operator *[shall]* **may** choose from the following options, unless otherwise ordered by the commission*[, and shall notify the commission by May 1, 1990, of which option or combination of options the* *operator will implement]*:

1. Conduct annual instrument leak detection surveys on all unprotected steel service lines and yard lines and implement a replacement program where all unprotected steel service lines and yard lines will be replaced by May 1, 1994;

2. Conduct annual instrument leak detection surveys on all unprotected steel service lines and unprotected steel yard lines. The operator shall compile a historical summary listing the cumulative number of unprotected steel service lines and yard lines installed, replaced, or repaired due to underground leakage and with active underground leaks in a defined area. Based on the results of the summary, the operator shall initiate replacement, to be completed within eighteen (18) months, of all unprotected steel service lines and yard lines in a defined area once twenty-five percent (25%) or more meet the previously mentioned repair, replacement, and leakage conditions. At a minimum, ten percent (10%) of the customer-owned unprotected steel service lines in the system as of December 15, 1989, must be replaced annually. Beginning with calendar year 1994, a minimum of five percent (5%) of the unprotected steel yard lines, and operator-owned and installed unprotected steel service lines in the system as of December 15, 1989, must be replaced annually; and

3. Conduct annual instrument leak detection surveys on all unprotected steel service lines and unprotected steel yard lines and implement a replacement program. The program must prioritize replacements based on the greatest potential for hazards. At a minimum, ten percent (10%) of the customer-owned unprotected steel service lines in the system as of December 15, 1989, must be replaced annually. Beginning with calendar year 1994, a minimum of five percent (5%) of the unprotected steel yard lines, and operator-owned and installed unprotected steel service lines in the system as of December 15, 1989, must be replaced annually.

(17) Gas Distribution Pipeline Integrity Management (IM)

(B) What Do the Regulations in this Section Cover? (192.1003) *[This section prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this rule. A gas distribution operator, other than a master meter operator, must follow the requirements in subsections (17)(C)–(G). A master meter operator of a gas distribution line must follow the requirements in subsection (17)(H). Information about IM programs is available at http://primis.phmsa.dot.gov/dimp.]*

1. General. Unless exempted in paragraph (17)(B)2., this section prescribes minimum requirements for an IM program for any gas distribution pipeline covered under this rule, including liquefied petroleum gas systems. A gas distribution operator, other than a master meter operator, must follow the requirements in subsections (17)(C)–(G). A master meter operator must follow the requirements in subsection (17)(H).

2. Exceptions. Section (17) does not apply to an individual service line directly connected to a transmission, gathering, or production pipeline.

(C) What Must a Gas Distribution Operator (Other than a Master Meter Operator) Do to Implement this Section? (*[191.1005]* **192.1005**) No later than August 2, 2011, a gas distribution operator must develop and implement an integrity management program that includes a written integrity management plan as specified in subsection (17)(D).

Appendix E to 4 CSR 240-40.030
Appendix E*[/M]*—Table of Contents—Safety Standards—Transportation of Gas by Pipeline.

4 CSR 240-40.030(1) General
(L) Customer Notification**,** *[Required by]* Paragraph (12)(S)2.

4 CSR 240-40.030(3) Pipe Design
(K) Design of Copper Pipe **for Repairs**. (192.125)

(L) Additional Design Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.112)

4 CSR 240-40.030(5) Welding of Steel in Pipelines
(B) General. *[(192.223)]*

4 CSR 240-40.030(7) General Construction Requirements for Transmission Lines and Mains
(O) Additional Construction Requirements for Steel Pipe Using Alternative Maximum Allowable Operating Pressure. (192.328).

4 CSR 240-40.030(8) Customer Meters, Service Regulators, and Service Lines
(Q) Manual Service Line Shut-Off Valve Installation (192.385)

4 CSR 240-40.030(9) Requirements for Corrosion Control.
(B) How Does this *[Subsection]* **Section** Apply to Converted Pipelines and Regulated Onshore Gathering Lines? (192.452)

4 CSR 240-40.030(12) Operations
(M) Maximum Allowable Operating Pressure—Steel or Plastic Pipelines. (192.619 **and 192.620**)

4 CSR 240-40.030(13) Maintenance
(BB) Pressure Regulating, Limiting, and Overpressure Protection—Individual Service Lines Directly Connected to Production, Gathering, or Transmission Pipelines. (192.740)

4 CSR 240-40.030(17) Gas Distribution Pipeline Integrity Management (IM)
(C) What Must a Gas Distribution Operator (Other than a Master Meter Operator) Do to Implement this Section? *[(191.1005)]* **(192.1005)**

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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 this proposed amendment with the Missouri Public Service Commission, Morris L. Woodruff, Secretary of the Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received at the commission's offices on or before August 15, 2018, and should include a reference to Commission Case No. GX-2018-0279. 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 August 20, 2018 at 10:00 a.m., 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 4—DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

4 CSR 240-40.080 Drug and Alcohol Testing. The commission is amending sections (1) and (4).

PURPOSE: This amendment modifies the rule to address any amendments of 49 CFR parts 40 and 199 promulgated between October 2015 and September 2017.

(1) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, *[2015]* **2017**, 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, *[2015]* **2017** version of 49 CFR parts 40 and 199 is available at www.gpo.gov/fdsys/search/showcitation.action.

(4) For purposes of this rule, the following substitutions should be made for certain references in the federal pipeline safety regulations adopted by reference in section (2) of this rule:

(D) The references to the applicability exemptions for operators of master meter systems as defined in section "191.3 of this chapter" in 49 CFR 199.2 should refer to *["4 CSR 240-40.020(2)(F)"]* **"4 CSR 240-40.020(2)(G)"** instead.

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. Original rule filed Nov. 29, 1989, effective April 2, 1990. For intervening history, please consult the ***Code of State Regulations****. Amended: Filed June 4, 2018.*

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 this proposed amendment with the Missouri Public Service Commission, Morris L. Woodruff, Secretary of the Commission, 200 Madison Street, PO Box 360, Jefferson City MO 65102-0360. To be considered, comments must be received at the commission's offices on or before August 15, 2018, and should include a reference to Commission Case No. GX-2018-0279. 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 August 20, 2018 at 10:00 a.m., 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 10—DEPARTMENT OF NATURAL RESOURCES
Division 20—Clean Water Commission
Chapter 4—Grants and Loans

PROPOSED RESCISSION

10 CSR 20-4.010 Construction Grant and Loan Priority System. This rule set forth the system used by the commission to prioritize projects for the Environmental Protection Agency wastewater treatment construction grants program, the state matching grant program and the state construction grants program. This rule set forth state eligibility limitations for grants under the Environmental Protection Agency wastewater treatment construction grants program and the state matching grant program. This rule also set forth the methods used by the commission to develop and modify lists of grant projects eligible for funding under the Environmental Protection Agency wastewater treatment construction grants program and the state matching grant program.

PURPOSE: This rule is being rescinded. Section (1) Priority Point System will be deleted and the department will create Priority Point Criteria to be noticed annually for public comment and adopted by the Clean Water Commission. Proposed to move section (2) Priority Lists and Section (3) Modifications to 10 CSR 20-040 State Revolving Fund General Assistance Regulation.

AUTHORITY: section 644.026, RSMo 2000. Original rule filed Dec. 4, 1975, effective Dec. 14, 1975. For intervening history, please consult the ***Code of State Regulations****. Rescinded: Filed June 13, 2018.*

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

PRIVATE COST: This proposed rescission 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 this proposed rescission with the Department of Natural Resources, Division of Environmental Quality, Water Protection Program, attn. Hannah Humphrey, PO Box 176, Jefferson City, MO 65102 or to fac@dnr.mo.gov. To be considered, comments must be received by the close of the public comment period on August 23, 2018 at 5:00 p.m. A public hearing is scheduled for the Clean Water Commission to be held at 10 a.m. on August 15, 2018 at the Department of Natural Resources, Elm Street Conference Center, Bennett Spring/Roaring River Conference Rooms, 1730 East Elm Street, Jefferson City, MO 65101.

Title 10—DEPARTMENT OF NATURAL RESOURCES
Division 20—Clean Water Commission
Chapter 4—Grants and Loans

PROPOSED AMENDMENT

10 CSR 20-4.030 Grants for Sewer Districts and Certain Small Municipal Sewer Systems. The department is amending the purpose of the rule; renumbering the sections within this rule; amending subsection (1)(A) Grant Application Requirements; updating terminology in subsection (1)(A); adding "cost" to the preliminary engineering study in subsection (1)(D); modifying the language in subsection (1)(D) to replace latest census with most recent decennial census and adding an income survey overseen by a state or federal agency; including additional language under paragraphs (1)(D)5.–6. and renumbering this section; updating terminology under section (2); deleting the grant limitations and maximum grant amount under subsection (2)(B);