BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Establishment of a Working Case for the Review and Consideration of Amending the Commission's Natural Gas Safety Rules	)))	**File No. GW-2022-XXXX**

STAFF MOTION TO ESTABLISH WORKING CASE

COMES NOW the Staff of the Missouri Public Service Commission, by and through undersigned counsel, and for its *Staff Motion to Establish Working Case* states as follows:

1. Staff requests the Commission open a working docket for the purpose of updating the Commission's gas safety rules to reflect recent U.S. Department of Transportation rule changes and reflect certain clarifications and editorial revisions.

2. Federal law requires that the State of Missouri take measures to adopt each applicable federal pipeline safety standard within a prescribed period of time.[1] Goals are set for state programs by the Pipeline and Hazardous Materials Administration (PHMSA) and enforcement of those goals is by reductions in federal grant-in-aid funding and the potential loss of federal certification if those goals are not met.[2]

3. The recent amendments to Commission Rules 20 CSR 4240-40.020 and 20 CSR 4240-40.030, proposed in Case Nos. GW-2021-0272 and GX-2021-0406, became effective on January 31, 2022. Staff has considered the Federal Rule

---

[1] 49 U.S. Code § 60105 requires, among other things, that the state authority adopt each applicable federal pipeline safety standard by the date of its annual certification, or in the event a standard was established within 120 days before the date of the certification, be taking steps to adopt that standard.

[2] The Commission's Safety Engineering Department Staff is granted authority to implement the state pipeline safety program by annual certification from the U.S. Department of Transportation (DOT). The annual certification contemplates that a state agency may adopt a safety standard that is additional to or more stringent than the applicable federal standards.

amendments published as final rules subsequent to the draft rule amendments filed in Case No. GW-2021-0272.[3] Staff is proposing to adopt these Federal Rule amendments into the Commission's rules except as described in Paragraph 4.A. below. Staff is also proposing additional amendments as clarifications and editorial changes as described in Paragraph 4.B. below. Staff has provided a color-coded copy of its proposed amendments as described in Paragraph 4.C. below.

4. The full text of proposed amendments, attached hereto and labeled as Attachment A, include portions of Commission Rules 20 CSR 240-40.020 and 20 CSR 240-40.030 and are as follows:.

A. MO PSC Staff is proposing to adopt the provisions of federal rule amendments published as final rules from January – December 2021, except as follows:

1. For Docket No. PHMSA–2018–0046; Amdt Nos. 191–29; 192–128, Pipeline Safety: Gas Pipeline Regulatory Reform, final rule published in Federal Register / Vol. 86, No. 6 /January 11, 2021, corrections published in Federal Register / Vol. 86, No. 42 / March 5, 2021

   a. Staff is not proposing to adopt changes to Table 2 to Paragraph (d)(2)(iv) or Table 3 to Paragraph (e)(4) of 49 CFR 192.121 because these tables pertain to PA-11 and PA-12 pipe, which has not been adopted for use in the Commission's rules.

   b. For the sake of brevity, Staff's proposal contains a reference to the federal requirements adopted in 49 CFR 192.153(e). The federal code language will be added to 20 CSR 4240-40.030(4)(H)3. at the time of the filing the proposed CSR amendment in a GX case.

   c. Staff is not proposing to adopt changes to 49 CFR 192.481 that extends the interval between inspections of service lines for atmospheric corrosion from 3 years (Not to exceed 39 months) to 5 years (Not to exceed 63 months). Staff notes that the purpose cited in the federal rule amendment was to coordinate timing between leakage survey intervals (5 years in federal) with atmospheric corrosion monitoring of service lines. Staff further notes that

[3] See Federal Register, Vol. 86, No. 6, January 11, 2021, Vol. 86, No. 42, March 5, 2021, and Federal Register, Vol. 86, No. 217, November 15, 2021.

Commission rules provide a maximum interval between leakage surveys of three years, not to exceed 39 months, so the intervals for leakage surveys and atmospheric corrosion monitoring are the same (3 years not to exceed 39 months) in Commission rules.

d. Staff is proposing to adopt changes to 49 CFR 192.491 that extends record retention for inspections under 49 CFR 192.481(a)(2) from 5 years to the longer of the two most recent atmospheric corrosions inspections or five years. Rather than limit this requirement to service lines as in the federal rule change, Staff has proposed that this apply to all atmospheric corrosion records required by 49 CFR 192.481.

e. Staff is not proposing to adopt changes to 49 CFR 192.740(c)(2) that exempts service lines included in a DIMP plan. Staff notes that the requirements of 20 CSR 4240.40.030(13)(BB) [49 CFR 192.740] apply only to operators with service lines directly commenced to a production, gathering or transmission pipeline that is not operated as part of a distribution system. Staff has discussed the current requirements of 20 CSR 4240.40.030(13)(BB) with Missouri operators to whom the requirements are applicable. Of those operators, only one desired a waiver, which was granted with additional conditions and reporting requirements in GE-2020-0295. Therefore Staff proposed not to adopt the less stringent federal rule, but will consider applications for waiver should additional operators wish to use the federal exemption.

2. For Docket No. PHMSA–2011–0023; Amdt. Nos.191–30; 192–129, Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, final rule published in Federal Register / Vol. 86, No. 217 /November 15, 2021:

   a. Staff is not proposing to adopt provisions specific to pipelines on the Outer Continental Shelf (OCS) as this location is not applicable to Missouri.

   b. Staff's proposal contains placeholders for revision dates of PHMSA Forms F 7100.2-2 and F7100.2-3, since the final versions have not been place on the PHMSA website yet – approval month/year is shown as {pending}. This will be revised at the time of filing the proposed CSR amendment in a GX case.

B. Additionally, MO PSC Staff proposed to the following amendments as clarifications and editorial changes:

1. In 20 CSR 4240-40.020(1)(A), Staff proposes to add wording to match with the onshore portion of 49 CFR 191.1(a).

2. In 20 CSR 4240-40.020 (5)(B), (5)(G), (6)(A), (7)(A),(9)(A),(9)(C),(10)(A), and (10)(B), Staff proposes to update the PHMSA forms to the current revisions at the PHMSA website.

3. In 20 CSR 4240-40.030(1)(H), Staff proposes to delete the word "steel". This will make the conversion to service criteria in (1)(H)A. – D. also applicable to plastic pipelines.

4. In 20 CSR 4240-40.030(12)(I)3.A., Staff proposed changing "… prior to December 1 of each calendar year" to "…. within the one-call notification center participation renewal period." Typically the MOCS participation renewal period has been January – March dates. (The requirement to update once each calendar year with intervals not exceeding 15 months will still be in effect).

5. In 20 CSR 4240-40.030(13)(BB), Staff proposed to change the reference to (4)(DD)2 to (4)(DD). This would make it consistent with federal rule 192.740, which references 192.197 (Missouri (4)(DD)).

C. In the text showing Staff's proposed changes, the following color code is used:

For proposed amendments to address federal rule changes in Docket No. PHMSA–2011–0023; Amdt. Nos. 191–30; 192–129, Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments, published in: Federal Register / Vol. 86, No. 217 / Monday, November 15, 2021. Federal Register :: Pipeline Safety: Safety of Gas Gathering Pipelines: Extension of Reporting Requirements, Regulation of Large, High-Pressure Lines, and Other Related Amendments bracket, italics and grey highlighting are used to show text to be deleted, and bold with grey highlighting shows text to be added.

For proposed amendments to address federal rule changes in Docket No. PHMSA–2018–0046; Amdt Nos. 191–29; 192–128, Pipeline Safety: Gas Pipeline Regulatory Reform, final rule published in Federal Register / Vol. 86, No. 6 /January 11, 2021, corrections published in Federal Register / Vol. 86, No. 42 / March 5, 2021. Federal Register :: Pipeline Safety: Gas Pipeline Regulatory Reform brackets, italics and green highlighting are used to show text to be deleted, and bold with green highlighting shows text to be added.

For proposed rule clarifications and editorial changes that are not directly associated with the above referenced federal amendments, brackets, italics and yellow highlighting are used to show text to be deleted, and bold with yellow highlighting shows text to be added.

5. Staff's Motion further requests the Commission invite stakeholders to respond with comments regarding the proposed gas safety rule amendments and the cost impact, if any, of the proposed gas safety rule amendments by May 2, 2022. If a cost impact is included, the comment should also indicate if there is any cost impact due to proposed amendments highlighted in yellow since any costs due to proposed amendments highlighted in grey and green were already considered during the Federal amendment rulemakings.

6. Attached is an updated service list of all stakeholders from the previous gas safety rules working docket, Case No. GW-2021-0272, attached hereto and labeled as Attachment B. Staff requests the Commission direct its data center to provide notice of this working case and invitation to comment to all stakeholders listed on Attachment B.

WHEREFORE, Staff respectfully requests the Commission to issue an order that: 1) opens a working docket to address the attached proposed natural gas safety rule amendments with notice provided to those in the attached service list; and 2) invites stakeholders in this docket to submit comments regarding the proposed rule amendments and their cost impact, if any, and to do so by May 2, 2022.

Respectfully submitted,

/s/ Jamie S. Myers
Jamie S. Myers
Deputy Counsel
Mo. Bar No. 68291
200 Madison St, Ste. 800
P.O. Box 360
Jefferson City, MO 65102
Phone: 573-526-6036
Fax: 573-751-9285
E-mail: jamie.myers@psc.mo.gov

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing have been mailed, hand-delivered, or transmitted by facsimile or electronic mail to counsel of record as reflected on the certified service list maintained by the Commission in its Electronic Filing Information System this 7th day of March, 2022.

/s/ Jamie S. Myers

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

PROPOSED AMENDMENT

20 CSR 4240-40.020 Incident, Annual, and Safety-Related Condition Reporting Requirements. The Commission Staff proposes amending sections (1), (2), (5), (6), (7), (9), (10), (12) and (14).

PURPOSE: This amendment modifies the rule to address amendments of 49 CFR part 191 promulgated between January 2021 and December 2021, and makes clarification and editorial changes.

(1) Scope. (191.1)

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

(B) *[This rule does not apply to]***Subsections (11)(B) and (11)(C) and section (12) do not apply to the onshore** gathering of gas—

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

2. Through a pipeline that is not a regulated onshore gathering line*[(as determined in 20 CSR 4240-40.030(1)(E) (192.8))]*.

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

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

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

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

B. Estimated property damage of *[fifty thousand dollars ($50,000)]***one hundred, twenty-two thousand dollars ($122,000)** or more, including loss to the operator and others, or both, but excluding the cost of gas lost. **For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with appendix A to 49 CFR part 191**; or

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

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

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

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

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

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

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

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

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

(5) Report Submission Requirements. (191.7)

(B) Missouri Incident Reports.

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

2. The incident report forms for gas distribution systems (PHMSA F 7100.1, revised *[April 2019]* **May 2021**), gas transmission and gathering pipeline systems (PHMSA F 7100.2, revised *[April 2019]* **January 2020**), and LNG facilities (PHMSA F 7100.3, revised April 2019) are incorporated by reference in subsection (5)(G).

(G) Forms Incorporated by Reference.

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

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

B. U.S. Department of Transportation Form PHMSA F 1000.2, revised January 2020. The PHMSA F 1000.2 form is the National Registry Notification form for reporting changes including operator name change, change in entity operating, shared safety program change, change in ownership for gas facilities, construction or rehabilitation of gas facilities, change in ownership for LNG, and construction for LNG. The PHMSA F 1000.2 form does not include any amendments or additions to the January 2020 version.

C. U.S. Department of Transportation Form PHMSA F 7100.1, revised *[April 2019]* **May 2021**. The PHMSA F 7100.1 form is the incident report form for gas distribution systems and does not include any amendments or additions to the *[April 2019]* **May 2021** version.

D. U.S. Department of Transportation Form PHMSA F 7100.1-1, revised *[October 2018]* **May 2021**. The PHMSA F 7100.1-1 form is the annual report form for gas distribution systems and does not include any amendments or additions to the *[October 2018]* **May 2021**version.

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

F. U.S. Department of Transportation Form PHMSA F 7100.2, revised *[April 2019]* **January 2020**. The PHMSA F 7100.2 form is the incident report form for gas transmission and gathering pipeline systems and does not include any amendments or additions to the *[April 2019]* **January 2020** version.

G. U.S. Department of Transportation Form PHMSA F 7100.2-1, revised October *[2014]* **2021**. The PHMSA F 7100.2-1 form is the annual report form for gas transmission and gathering pipeline systems and does not include any amendments or additions to the October 2014 version.

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

I. U.S. Department of Transportation Form PHMSA F 7100.3-1, revised *[August 2017]* **October 2014**. The PHMSA F 7100.3-1 form is the annual report form for LNG facilities and does not include any amendments or additions to the August 2017 version.

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

K. U.S. Department of Transportation Form PHMSA 7100.2-2, approved *{pending}*. The PHMSA F 7100.2-2 form is the incident report form for reporting-regulated gathering pipeline systems and does not include any amendments or additions to the *{pending}* version.

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

2. The forms listed in paragraph (5)(D)1. are published by the U.S. Department of Transportation Office of Pipeline Safety, PHP-10, 1200 New Jersey Avenue SE, Washington, DC 20590-0001. The forms are

available at www.phmsa.dot.gov/forms/pipeline-forms or upon request from the pipeline safety program manager at the address given in subsection (5)(E).

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

(A) Except as provided in subsection (6)(C), each operator of a distribution pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.1 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised *[April 2019]* **May 2021**) is incorporated by reference in subsection (5)(G).

(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 *[October 2018]* **May 2021**) is incorporated by reference in subsection (5)(G).

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

(B) **Reserved.** *[Mechanical Fitting Failure Reports. (191.12)*

1. Each mechanical fitting failure, as required by 20 CSR 4240-40.030(17)(E) (192.1009), must be submitted on a Mechanical Fitting Failure Report Form (U.S. Department of Transportation Form PHMSA F 7100.1–2). An operator must submit a m5echanical fitting failure report for each mechanical fitting failure that occurs within a calendar year not later than March 15 of the following year. Alternatively, an operator may elect to submit its reports throughout the year. In addition, an operator must also report this information to designated commission personnel.

2. The Mechanical Fitting Failure Report Form (October 2014) is incorporated by reference in subsection (5)(G).]

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

(A) Transmission or Gathering.

1. Each operator of a transmission or a **regulated onshore** gathering pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). See the report submission requirements in subsection (5)(A). The incident report form (revised *[April 2019]* **January 2020**) is incorporated by reference in subsection (5)(G).

2. Each operator of a reporting-regulated gathering pipeline system must submit U.S. Department of Transportation Form PHMSA F 7100.2–2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5) that occurs after May 16, 2022. See the report submission requirements in subsection (5)(A). The incident report form (revised *{pending}*) is incorporated by reference in subsection (5)(G).

(C) Underground natural gas storage facility. Each operator of an UNGSF must submit U.S. Department of Transportation Form PHMSA F 7100.2 as soon as practicable but not more than thirty (30) days after detection of an incident required to be reported under section (3) (191.5). **See the report submission requirements in subsection (5)(A).** The incident report form (revised *[April 2019]* **January 2020**) is incorporated by reference in subsection (5)(G).

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

(A) Transmission or Gathering.

1. Each operator of a transmission or a **regulated onshore** gathering pipeline system must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (revised October *[2014]* **2021**) is incorporated by reference in subsection (5)(G).

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

(B) LNG. Each operator of a liquefied natural gas facility must submit an annual report for that system on U.S. Department of Transportation Form PHMSA F 7100.3-1 This report must be submitted each year, not later than March 15, for the preceding calendar year. See the report submission requirements in subsection (5)(A). The annual report form (revised *[August 2017]* **October 2014**) is incorporated by reference in subsection (5)(G).

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

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

1. Exists on a master meter system**, a reporting-regulated gathering pipeline,** or a customer-owned service line;

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

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

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

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

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

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

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

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

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.020. Original rule filed Feb. 5, 1970, effective Feb. 26, 1970. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed Feb. 8, 1985, effective Aug. 11, 1985. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Dec. 14, 2000, effective May 30, 2001. Amended: Filed Oct. 15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May 30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019. Moved to 20 CSR 4240-40.020, effective Aug. 28, 2019. Amended: Filed Dec. 12, 2019, effective July 30, 2020. Amended: Filed June 29, 2021, effective Jan. 30, 2022.* **Amended: Filed Date.**

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

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

PROPOSED AMENDMENT

20 CSR 4240-40.030 Safety Standards—Transportation of Gas by Pipeline. The Commission Staff proposes amending sections (1), (3), (4), (5), (6), (9), (10), (12), (13), (17) and Appendices B and E.

PURPOSE: This amendment modifies the rule to address amendments of 49 CFR part 192 promulgated between January 2021 and December 2021, 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. Composite materials means materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

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

[8.] **9.** 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.] **10.** Customer meter means the meter that measures the transfer of gas from an operator to a consumer;

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

[11.] **12.** Distribution line means a pipeline other than a gathering or transmission line;

[12.] **13.** 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.] **14.** Engineering critical assessment (ECA) means a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure;

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

[15.] **16.** 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;

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

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

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

[19.] **20.** 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;

[20.] **21.** 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;

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

[22.] **23.** 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;

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

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

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

[26.] **27.** Moderate consequence area means—

A. An onshore area that is within a “potential impact circle” as defined in 49 CFR 192.903 (incorporated by reference in section (16)), containing either—

(I) Five (5) or more buildings intended for human occupancy; or

(II) Any portion of the paved surface (including shoulders) of a designated “interstate,” “other freeway or expressway,” as well as any “other principal arterial” roadway with four (4) or more lanes, as defined in the Federal Highway Administration’s *Highway Functional Classification Concepts, Criteria and Procedures*, Section 3.1 (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf), and that does not meet the definition of “high consequence area” in 49 CFR 192.903 (incorporated by reference in section (16)); and

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

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

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

[29.] **30.** 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;

[30.] **31.** 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);

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

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

[33.] **34.** 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;

[34.] **35.** 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;

[35.] **36.** 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;

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

[37.] **38.** 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;

[38.] **39.** 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;

[39.] **40.** 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]);

[40.] **41.** 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;

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

[42.] **43.** 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;

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

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

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

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

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

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

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

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

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, *[2019]***2020**, and the subsequent amendment 192-*[125]***128** (published in *Federal Register* on *[October 1, 2019]***January 11, 2021**, page *[84]***86** FR *[52180]***2210**), 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, *[2019]***2020** version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. The *Federal Register* publication on page **86**[*84*] FR **2210**[*52180*] is available at *[https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf]* **https://www.govinfo.gov/content/pkg/FR-2021-01-11/pdf/2021-00208.pdf**.

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

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

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

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

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

(E) Gathering Lines. (192.8 and 192.9)

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, *[2019]***2020**, and the subsequent amendment 192-**129***[125]* (published in *Federal Register* on **November 15, 2021***[October 1, 2019]*, page **86***[84]* FR **63266***[52180]*), the federal regulations at 49 CFR 192.8 and 192.9 are incorporated by reference and made a part of this rule. This rule does not incorporate any subsequent amendments to 49 CFR 192.8 and 192.9.

2. The *Code of Federal Regulations* is published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, *[2019]***2020** version of 49 CFR part 192 is available at https://www.govinfo.gov/#citation. The *Federal Register* publication on page **86 FR 63266 is available at https://www.govinfo.gov/content/pkg/FR-2021-11-15/pdf/2021-24240.pdf***[84 FR 52180 is available at https://www.govinfo.gov/content/pkg/FR-2019-10-01/pdf/2019-20306.pdf]*.

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

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

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

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

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

1. No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless—

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

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

Pipeline	**Date**
Regulated onshore gathering **pipe**line to which **this rule** *[49 CFR 192.8 and 192.9]* did not apply until April 14, 2006 (see (1)(E))	March 15, 2007
Regulated onshore gathering pipeline to which this rule did not apply until May 16, 2022 (see (1)(E))	**May 16, 2023**
All other pipelines	March 12, 1971

2. No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless that replacement, relocation, or change has been made according to the requirements in this rule.

Pipeline	**Date**
Regulated onshore gathering **pipe**line to which **this rule** *[49 CFR 192.8 and 192.9]* did not apply until April 14, 2006 (see (1)(E))	March 15, 2007
Regulated onshore gathering pipeline to which this rule did not apply until May 16, 2022 (see (1)(E))	**May 16, 2023**
All other pipelines	November 12, 1970

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

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

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

1. Except as provided in paragraph (1)(H)4., a *[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 20 CSR 4240-40.020(11).

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

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

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

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

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

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

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

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

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

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

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

(3) Pipe Design.

(I) Design of Plastic Pipe. (192.121)

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

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

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

where

P = Design pressure, psi (kPa) gauge;

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

t = Specified wall thickness, inches (millimeters);

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

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

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

2. General Requirements for Plastic Pipe and Components.

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

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

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

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

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

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

3. Polyethylene (PE) Pipe Requirements.

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

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

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

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

(III) The pipe has a nominal size (IPS or CTS) of [*12*]**24** inches or less; and

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

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

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

(4) Design of Pipeline Components.

(H) Components Fabricated by Welding. (192.153)

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

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

A. Regularly manufactured butt-welding fittings;

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

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

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

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

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

5. *[A component having]* **The test requirements for a prefabricated unit or pressure vessel, defined for this paragraph as components with** a design pressure established in accordance with paragraph (4)(H)1. or 2. *[and subject to the strength testing requirements of paragraph (10)(C)2. must be tested to at least one and one-half (1.5) times the MAOP]* **are as provided at 49 CFR 192.153(e)**. *{GW case note: federal language will be added here for GX case in place of cross-reference.}*

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

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

2. This subsection does not apply to—

A. Manifolds;

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

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

D. Cross-overs;

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

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

G. Gathering lines; and

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

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

(II) Records: Pipeline Components. (192.205)

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

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

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

(5) Welding of Steel in Pipelines.

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

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

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

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

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

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

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

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

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

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

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

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

(6) Joining of Materials Other Than by Welding.

(F) Plastic Pipe (192.281)

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

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

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

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

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

3. Heat-fusion joints. Each heat-fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620*[-12]* (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D))**, or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints,** and the following:

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

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

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

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

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

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

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

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

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

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

1. Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under paragraph (6)(B)2. is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive

method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests, as applicable:

A. The test requirements of—

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

(II) *(Reserved)*;

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

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

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

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

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

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

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

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

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

2. The specimen joint must be—

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

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

(I) Tested under any one (1) of the test methods listed under paragraph (6)(G)1. (192.283[a]), *[or]* **and** for polyethylene heat fusion joints (except for electrofusion joints) visually inspected *[and tested]* in accordance with ASTM F2620*[-12]* (incorporated by reference in 49 CFR 192.7 and adopted in subsection

(1)(D))**, or a written procedure that has been demonstrated to provide an equivalent or superior level of safety,** applicable to the type of joint and material being tested;

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

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

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

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

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

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

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

(9) Requirements for Corrosion Control.

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

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

2. *[Regulated]* **Type A and B** onshore gathering lines. For any *[regulated]* **Type A and B** onshore gathering line *[to which 49 CFR 192.8 and]* **under 49 CFR** 192.9 *[did not apply until]* **existing on** April 14, 2006, **that was not previously subject to this part,** and for any gathering line that becomes a regulated onshore gathering line under subsection (1)(E) **(192.9) after April 14, 2006,** because of a change in class location or increase in dwelling density:

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

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

3. Type C onshore regulated gathering lines. For any Type C onshore regulated gathering pipeline under subsection (1)(E) (192.9) existing on May 16, 2022, that was not previously subject to this rule, and for any Type C onshore gas gathering pipeline that becomes subject to section (9) after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site:

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

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

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

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

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

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

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

4. Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring 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. 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.

(V) Corrosion Control Records. (192.491)

1. Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode. Each operator shall develop and maintain maps showing, at a minimum: the location of cathodically protected mains (except for short sections less than one hundred feet (100') in length); feeder lines; and transmission lines; and all cathodic protection facilities such as rectifiers, test points (except for service riser locations that are not used each year), electrical isolating devices that separate protection zones, and interference bonds.

2. Each record or map required by paragraph (9)(V)1. must be retained for as long as the pipeline remains in service.

3. Each operator shall maintain a record of each test, survey, inspection, and remedial action required by this section in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least five (5) years **with the following exceptions:**[*, except that*]

a. Operators must retain records related to paragraphs (9)(I)1., (9)(I)4., (9)(I)5., and (9)(N)2. [*must be retained*] for as long as the pipeline remains in service[*.*]**, and**

b. Operators must retain records of atmospheric corrosion inspections of each pipeline that is being inspected under paragraph (9)(Q) for the longer of the two most recent atmospheric corrosion inspections or five (5) years.

(10) Test Requirements.

(D) Test Requirements for Pipelines to Operate at a Hoop Stress Less Than Thirty Percent (30%) of SMYS and at or Above One Hundred (100) psi (689 kPa) Gauge. (192.507) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than thirty percent (30%) of SMYS and at or above one hundred (100) psi (689 kPa) gauge must be tested in accordance with subparagraph (12)(M)1.B. and the following:

1. The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested;

2. If, during the test, the segment is to be stressed to twenty percent (20%) or more of SMYS and natural gas, inert gas, or air is the test medium—

A. A leak test must be made at a pressure between one hundred (100) psi (689 kPa) gauge and the pressure required to produce a hoop stress of twenty percent (20%) of SMYS; or

B. The line must be walked to check for leaks while the hoop stress is held at approximately twenty percent (20%) of SMYS;

3. The pressure must be maintained at or above the test pressure for at least one (1) hour.

4. For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation pressure test must be conducted in accordance with the requirements of this subsection.

(12) Operations.

(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 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]* **within the one-call notification center participation renewal period**. This list should at least include, but not be limited to, the following:

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

(II) Telephone company;

(III) Electric utilities and co-ops;

(IV) Water and sewer utilities;

(V) City governments;

(VI) County governments;

(VII) Special road districts;

(VIII) Special water and sewer districts; and

(IX) Highway department district(s);

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B. The proximity to the operator's facilities;

C. The type of excavating equipment involved;

D. The importance of the operator's facilities;

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

F. The potential for serious incident should damage occur;

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

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

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

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

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

B. Pipelines that are part of a petroleum gas system subject to subsection (1)(F) (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.

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

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

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

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

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

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

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

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

Class Location	Factors[1,2], Segment -

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

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

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

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

Pipeline Segment	Pressure Date	Test Date
Onshore **regulated** gathering **pipe**line **(Type A or Type B under 49 CFR 192(b))** that first became subject to *[49 CFR 192.8 and 192.9]* **this rule** after April 13, 2006 (see subsection (1)(E)).	March 15, 2006, or date line becomes subject to this rule, whichever is later.	Five (5) years preceding applicable date in second column.
Onshore regulated gathering pipeline (Type C under 49 CFR 192.9(d)) that first became subject to this rule on or after May 16, 2022.	**May 16, 2023, or date pipeline becomes subject to this rule, whichever is later.**	**Five (5) years preceding applicable date in second column.**
Onshore transmission **pipe**line that was a gathering line not subject to *[49 CFR 192.8 and 192.9]* **this rule** before March 15, 2006 (see subsection (1)(E)).	March 15, 2006**, or date pipeline becomes subject to this rule, whichever is later.**	*[March 15, 2001]* **Five (5) years preceding applicable date in second column.**
All other pipelines.	July 1, 1970	July 1, 1965

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

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

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

A. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the five (5) years preceding the applicable date in the second column of the table in subparagraph (12)(M)1.C. An operator must still comply with subsection (12)(G).

B. For any Type C gas gathering pipeline under subsection (1)(E) (192.9) existing on or before May 16, 2022, that was not previously subject to this rule and the operator cannot determine the actual operating pressure of the pipeline for the five (5) years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA. The operator must notify PHMSA in accordance with subsection (1)M) (192.18). The notification must include the following information:

(I) The proposed MAOP of the pipeline;

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

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

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

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

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

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

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

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

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

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

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

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

(13) Maintenance.

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

1. This subsection applies, except as provided in paragraph (13)(BB)3., to any service line directly connected to a *[production, gathering, or]* transmission pipeline **or regulated gathering pipeline as determined in subsection (1)(E) (192.8)** that is not operated as part of a distribution system.

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

A. In good mechanical condition;

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

C. Set to control or relieve at the correct pressure consistent with the pressure limits of 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]***:**

A. A service line that only serve engines that power irrigation pumps**; or**

B. A service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in subsection (1)(E) (192.8).

(17) Gas Distribution Pipeline Integrity Management (IM).

(B)What Do the Regulations in this Section Cover? (192.1003)

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

2. Exceptions. Section (17) does not apply to**:**

A. Individual service lines *[an individual service line]* directly connected to a *[transmission, gathering, or production pipeline]* **production line or a gathering line other than a regulated onshore gathering line as determined in subsection (1)(E) (192.8);**

B. Individual service lines directly connected to either a transmission or regulated gathering pipeline and maintained in accordance with paragraphs (13)(BB)1. and 2. (192.740(a) and (b)); and

C. Master meter systems.

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

(D) What Are the Required Elements of an Integrity Management Plan? (192.1007) A written integrity management plan must contain procedures for developing and implementing the following elements:

1. Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

A. Identify the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

B. Consider the information gained from past design, operations, and maintenance.

C. Identify additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (e.g., design, construction, operations, or maintenance activities).

D. Develop and implement a process by which the IM program will be reviewed periodically and refined and improved as needed.

E. Provide for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

2. Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline: corrosion **(including atmospheric corrosion)**, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operation**s**, and other *[concerns]* **issues** that could threaten the integrity of its pipeline. An operator must consider reasonably

available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records **(including atmospheric corrosion records)**, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

3. Evaluate and rank risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services, and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

4. Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found).

5. Measure performance, monitor results, and evaluate effectiveness.

A. Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its IM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(I) Number of hazardous leaks either eliminated or repaired as required by paragraph (14)(C)1. (or total number of leaks if all leaks are repaired when found), categorized by cause;

(II) Number of excavation damages;

(III) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);

(IV) Total number of leaks either eliminated or repaired, categorized by cause;

(V) Number of hazardous leaks either eliminated or repaired as required by paragraph (14)(C)1. (or total number of leaks if all leaks are repaired when found), categorized by material; and

(VI) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

6. Periodic evaluation and improvement. An operator must re-evaluate threats and risks on its entire pipeline and consider the relevance of threats in one (1) location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five (5) years. The operator must consider the results of the performance monitoring in these evaluations.

7. Report results. Report, on an annual basis, the four (4) measures listed in parts (17)(D)5.A.(I)–(IV), as part of the annual report required by 20 CSR 4240-40.020(7)(A). An operator also must report the four (4) measures to designated commission personnel.

(E) **Reserved.** *[What Must an Operator Report When a Mechanical Fitting Fails? (192.1009)*

1. Except as provided in paragraph (17)(E)2., each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a nonhazardous leak. The report(s) must be submitted in accordance with 20 CSR 4240-40.020(7)(B) (191.12).

2. The mechanical fitting failure reporting requirements in paragraph (17)(E)1. do not apply to master meter operators.]

(H) What Must a *[Master Meter]* **Small LPG** Operator Do to Implement this Section? (192.1015)

1. General. No later than August 2, 2011, the **small LPG** operator *[of a master meter system]* must develop and implement an IM program that includes a written IM plan as specified in paragraph (17)(G)2. The IM program for these pipelines should reflect the relative simplicity of these types of pipelines.

2. Elements. A written integrity management plan must address, at a minimum, the following elements:

A. Knowledge. The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (e.g., design, construction, operations, or maintenance activities);

B. Identify threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation;

C. Rank risks. The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat;

D. Identify and implement measures to mitigate risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline;

E. Measure performance, monitor results, and evaluate effectiveness. The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes; and

F. Periodic evaluation and improvement. The operator must determine the appropriate period for conducting IM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire program at least every five (5) years. The operator must consider the results of the performance monitoring in these evaluations.

3. Records. The operator must maintain, for a period of at least ten (10) years, the following records:

A. A written IM plan in accordance with this subsection, including superseded IM plans;

B. Documents supporting threat identification; and

C. Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's IM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's program.

Appendix B to 20 CSR 4240-40.030

Appendix B—Qualification of Pipe and Components

I. List of Specifications.

A. Listed Pipe Specifications.

ANSI/API ANSI/API Specification 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A106/A106M—Steel pipe, "Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A333/A333M—Steel pipe, "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A381—Steel pipe, "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A671/A671M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A672/A672M—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM A691/A691M—Steel pipe, "Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513*[–12ae1]*, "Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F2817–10 ''Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

B. Other Listed Specifications for Components.

ASME B16.40–2008 ''Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems'' (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM D2513*[–12ae1]* ‘‘Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings’’ (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1055–98 (2006) ‘‘Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing’’ (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1924–12 ‘‘Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing’’ (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1948–12 ‘‘Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing’’ (incorporated by reference, in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F1973–13 ‘‘Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA 11) and Polyamide 12 (PA 12) Fuel Gas Distribution Systems’’ (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

ASTM F2817–10 ‘‘Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair’’ (incorporated by reference in 49 CFR 192.7 and adopted in subsection (1)(D)).

Appendix E to 20 CSR 4240-40.030

Appendix E—Table of Contents—Safety Standards—Transportation of Gas by Pipeline.

20 CSR 4240-40.030(13) Maintenance

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

20 CSR 4240-40.030(17) Gas Distribution Pipeline Integrity Management (IM)

(C) What Must a Gas Distribution Operator (Other than a *[Master Meter]* **Small LPG** Operator) Do to Implement this Section? (192.1005)

(E) **Reserved.** *[What Must an Operator Report When a Mechanical Fitting Fails? (192.1009)*

(H) What Must a *[Master Meter]* **Small LPG** Operator Do to Implement this Section? (192.1015)

AUTHORITY: sections 386.250, 386.310, and 393.140, RSMo 2016. This rule originally filed as 4 CSR 240-40.030. Original rule filed Feb. 23, 1968, effective March 14, 1968. Amended: Filed Dec. 28, 1970, effective Jan. 6, 1971. Amended: Filed Dec. 29, 1971, effective Jan. 7, 1972. Amended: Filed Feb. 16, 1973, effective Feb. 26, 1973. Amended: Filed Feb. 1, 1974, effective Feb. 11, 1974. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Emergency amendment filed Jan. 17, 1977, effective Jan. 27, 1977, expired May 27, 1977. Amended: Filed Jan. 17, 1977, effective June 1, 1977. Emergency amendment filed March 15, 1978, effective March 25, 1978, expired July 23, 1978. Amended: Filed March 15, 1978, effective July 13, 1978. Amended: Filed July 5, 1978, effective Oct. 12, 1978. Amended: Filed July 13, 1978, effective Oct. 12, 1978. Amended: Filed Jan. 12, 1979, effective April 12, 1979. Amended: Filed May 27, 1981, effective Nov. 15, 1981. Amended: Filed Dec. 28, 1981, effective July 15, 1982. Amended: Filed Jan. 25, 1983, effective June 16, 1983. Amended: Filed Jan. 17, 1984, effective June 15, 1984. Amended: Filed Nov. 16, 1984, effective April 15, 1985. Amended: Filed Jan. 22, 1986, effective July 18, 1986. Amended: Filed May 4, 1987, effective July 24, 1987. Amended: Filed Feb. 2, 1988, effective April 28, 1988. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. Amended: Filed Dec. 14, 2000, effective May 30, 2001. Amended: Filed Oct. 15, 2007, effective April 30, 2008. Amended: Filed Nov. 29, 2012, effective May 30, 2013. Amended: Filed Nov. 14, 2016, effective June 30, 2017. Amended: Filed June 4, 2018, effective Jan. 30, 2019. Amended: Filed Dec. 12, 2019, effective July 30, 2020. Amended: Filed June 29, 2021, effective Jan. 30, 2022.* **Amended: Filed Date.**

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

Fields v. Missouri Power & Light Company*, 374 SW2d 17 (Mo. 1963). Violations of general law, municipal ordinances, rules of the Public Service Commission and the like are considered and held to be negligence per se. Here, violation of a rule of a private gas company filed with the P.S.C. cannot result in the creation of a cause of action in favor of another person separate and apart from an action based on common law negligence.*

MISSOURI PUBLIC SERVICE COMMISSION
Service List

Missouri Public Service Commission
Staff Counsel Department 200
Madison Street, Suite 800
P.O. Box 360
Jefferson City, MO 65102
staffcounselservice@psc.mo.gov

Office of the Public Counsel
Marc Poston
200 Madison Street, Suite 650
P.O. Box 2230
Jefferson City, MO 65102
opcservice@opc.mo.gov

City Utilities of Springfield, Missouri
Legal Department
301 E. Central
P.O. Box 551
Springfield, MO 65801
info@cityutilities.net

Dogwood Energy, LLC
Attn: EH&S Coordinator
P.O. Box 110
Pleasant Hill, MO 64080

Empire District Gas Company, The
Legal Department
P.O. Box 127
602 S. Joplin Avenue
Joplin, MO 64802

Liberty Utilities (MNG)
Legal Department
2751 North High Street
Jackson, MO 63755

Spire, Inc.
Legal Department
700 Market Street, 6th Floor
St. Louis, MO 63101

Summit Natural Gas of Missouri, Inc.
Legal Department
2 Delorme Drive, Suite 100
Yarmouth, ME 04096

Union Electric Company
Legal Department
1901 Chouteau Avenue
P.O. Box 66149, Mail Code 1310
St. Louis, MO 63166
AmerenMOService@ameren.com

Albany Municipal Gas System
Attn: City Administrator
106 E. Clay Street
Albany, MO 64402

Altenburg-Frohna Municipal Gas System
Attn: Mayor of Frohna
Joint Utilities Gas Department
Frohna, MO 63748

Altenburg-Frohna Municipal Gas System
Attn: Utility Safety & Design, Inc.
#9 Executive Woods Court, Ste. 1
Belleville, IL 62226

Altenburg-Frohna Municipal Gas System
Attn: Mayor of Altenburg
9144 Main Street
P.O. Box 22
Altenburg, MO 63732

Amber Glenn Apartments
Attn: Mr. Jesse Da Villa
Mr. Allan Sheehy
2977 Highway K, Ste. 239
O'Fallon, MO 63368

Ameresco
Attn: Manager of Operations
111 Speen St. Ste. 410
Framingham, MO 01701

Bernie Municipal Gas System
Attn: Mayor of Bernie
P.O Box 605
101 W. Main Street
Bernie, MO 63822

Bethany Municipal Gas System
Attn: City Administrator
P.O. Box 344
206 N. 16th Street
Bethany, MO 64424

Bismark Municipal Gas System
Attn: Mayor of Bismark
P.O. Box 27
924 Center Street
Bethany, MO 63624

Clarence Municipal Gas System
Attn: Mayor of Clarence
P.O. Box 9
Clarence, MO 63437

Cuba Municipal Gas System
Attn: Mayor of Cuba
City Hall
P.O. Box K
202 N. Smith Street
Cuba, MO 65453

Dogwood Energy, LLC
Attn: Utility Safety & Design, Inc.
P.O. Box 206
28847 Highway 136
Unionville, MO 63565

Fulton Municipal Gas System
Attn: Director of Administration
P.O. Box 130
4th & Market Streets
Fulton, MO 65251

Granby Municipal Gas System
Attn: Mayor of Granby
P.O. Box 500
302 N. Main Street
Granby, MO 64844

Grant City Municipal Gas System
Attn: Mayor of Grant City
101 W. 3rd Street
P.O. Box 398
Grant City, MO 64456

Green City Municipal Gas System
Attn: Mayor of Green City
P.O. Box 235
#4 Green Street
Green City, MO 63545

Green City Municipal Gas System
Attn: Utility Safety & Design, Inc.
P.O. Box 206
28847 Hwy. 136
Unionville, MO 63565

Hermann Municipal Gas System
Attn: Public Works Director
1902 Jefferson Street
Hermann, MO 65041

John Knox Village
Attn: Manager of Facilities
400 NW Murray Rd.
Lee's Summit, MO 64081

Kennett Municipal Gas System
Attn: Superintendent of Utilities
P.O. Box 40
303 S. Anthony
Kennett, MO 63857

Laddonia Ethanol Plant
Attn: CFO and VP of Admin Services
Missouri Public Utility Alliance
1808 I-70 Dr., S.W.
Columbia, MO 65203

Liberal Municipal Gas System
Attn: Mayor of Liberal
P.O. Box 67
209 S. Main Street
Liberal, MO 64762

Linden Mobile Home Park
Attn: Mr. Jim Janecek
400 NE 76th Terrace
Kansas City, MO 64118

Macon Municipal Gas System
Attn: Mayor of Macon
P.O. Box 569
106 W. Bourke Street
Macon, MO 63552

Madison Municipal Gas System
Attn: Mayor of Madison
P.O. Box 141
209 S. Main Street
Madison, MO 65263

Marshall Municipal Utilities
Attn: Underground Facilities Director
75 East Morgan Street
Marshall, MO 65340

Mercer Municipal Gas System
Attn: Mayor of Mercer
City Hall
14402 State Street
Mercer, MO 64661

Middletown Municipal Gas System
Attn: Mayor of Middletown
City Hall
P.O. Box 127
203 Johnson Street
Middletown, MO 63359

Mid-Missouri Energy
Attn: Ryland Utlaut, President
15311 N. Saline 65 Hwy.
Malta Bend, MO 65339

Milan Municipal Gas System
Attn: Mayor of Milan
City Hall
P.O. Box 247
212 East Second Street
Milan, MO 63556

Monroe City Municipal Gas System
Attn: Mayor of Monroe City
City Hall
109 2nd Street
Monroe City, MO 63456

Montgomery City Municipal Gas System
Attn: Mayor of Montgomery City
723 North Sturgeon Street
Montgomery City, MO 63361

New Florence Municipal Gas System
Attn: Mayor of New Florence
P.O. Box 70
217 South Main Street
New Florence, MO 63363

New Haven and Berger Municipal Gas System
Attn: Mayor of Berger
404 Rosalie
Berger, MO 63014

New Haven Berger Municipal Gas System
Attn: Mayor of New Haven
City Hall
101 Front Street
New Haven, MO 63068

Perryville Municipal Gas System
Attn: City Administrator
215 North West Street
Perryville, MO 63775

Perry Municipal Gas System
Attn: Mayor
P.O. Box 280
127 E. Main Street
Perry, MO 63462

Paris Municipal Gas System
Attn: City Superintendent
25804 Business Highway
24
Paris, MO 65275

Plattsburg Municipal Gas System
Attn: City Administrator
114 Maple Street
Plattsburg, MO 64477

Potosi Municipal Gas System
Attn: Mayor
121 E. High Street
Potosi, MO 63664

Princeton Municipal Gas System
Attn: Mayor of Princeton
City Hall
507 West Main Street
Princeton, MO 64673

Richland Municipal Gas System
Attn: Mayor of Richland
P.O. Box 798
Richland, MO 65556

Saint Louis University
Attn: Mr. Michael Lucido
3545 Lindell Boulevard
Wool Center Room 223
St. Louis, MO 63103

Shelbina Municipal Gas System
Attn: Mayor of Shelbina
P.O. Box 646
116 East Walnut
Shelbina, MO 63468

Show-Me Ethanol, LLC
Attn: General Manager
26530 Hwy., 24 E.
Carrollton, MO 64633

Roeslein Alternative
Energy Services
Attn: President
9200 Watson Rd., Ste. 200
St. Louis, MO 63126

St. James Municipal Gas System
Attn: Mayor of St. James
P.O. Box 426
200 N. Bourbeuse Street
St. James, MO 65559

St. Robert Municipal Gas System
Attn: Mayor of St. Robert
194 Eastlawn Ave., Ste. A
St. Robert, MO 65584

Stanberry Municipal Gas System
Attn: City Administrator
130 W. First Street
Stanberry, MO 64489

Ashley Energy, LLC
Attn: Operations Manager
One Ashley Place
St. Louis, MO 63102

Unionville Municipal Gas System
Attn: Mayor of Unionville
P.O. Box 255
1611 Grant Street
Unionville, MO 63565

Unionville Municipal Gas System
Attn: Utility Safety & Design
Vice President of Engineering
P.O. Box 206
28847 Hwy. 136
Unionville, MO 63565

Waynesville Municipal Gas System
Attn: City Administrator
100 Tremont Drive
Waynesville, MO 65583

Wheaton Municipal Gas System
Attn: Mayor of Wheaton
P.O. Box 70
219 E. Main Street
Wheaton, MO 64874

Flower Box Motel
Attn: Mr. Tom Workman
722 West Spring Street
Neosho, MO 64540

Museum Hill Apartments
Ms. Joy Scharnhorst
Asset Manager-Fulson Asset Management
220 NW Executive Way
Lee's Summit, MO 64063

Omega Pipeline Company
Attn: DPW Bldg.
2222 1334 First
Street
Ft. Leonard Wood, MO 65473

Oronogo Municipal Gas System
Attn: Mayor of Oronogo
P.O. Box 201
653 E. Central Street
Oronogo, MO 64855

Missouri One Call System
Attn: John Lansford
824 Weathered Rock Rd,
Jefferson City, Missouri, 65101

Missouri One Call System
Attn: Derek Leffort
824 Weathered Rock Rd,
Jefferson City, Missouri, 65101