Robin Carnahan
Secretary of State

Administrative Rules Division
Rulemaking Transmittal Receipt

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Date Submitted to Administrative Rules Division: 10/15/2007
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Included with Rulemaking:

Cover Letter	10/15/2007
Affidavit for public cost	10/15/2007

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Secretary of State
Administrative Rules Division

RULE TRANSMITTAL

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Rule Number 4 CSR 240-40.030

Use a "SEPARATE" rule transmittal sheet for EACH individual rulemaking.

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TYPE OF RULEMAKING ACTION TO BE TAKEN

☐ Emergency rulemaking, include effective date
☒ Proposed Rulemaking
☐ Withdrawal ☐ Rule Action Notice ☐ In Addition ☐ Rule Under Consideration
☐ Order of Rulemaking
Effective Date for the Order
☐ Statutory 30 days OR Specific date

Does the Order of Rulemaking contain changes to the rule text? ☐ NO
☐ YES—LIST THE SECTIONS WITH CHANGES, including any deleted rule text:

Small Business Regulatory Fairness Board (DED) Stamp

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Secretary/Chief Regulatory Law Judge

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General Counsel

October 15, 2007

Honorable Robin Carnahan
Secretary of State
Administrative Rules Division
600 West Main Street
Jefferson City, Missouri 65101

Dear Secretary Carnahan:

Re: Proposed Rule 4 CSR 240-40.030

CERTIFICATION OF ADMINISTRATIVE RULE

I do hereby certify that the attached is an accurate and complete copy of the proposed rule lawfully submitted by the Missouri Public Service Commission for filing on this 15th day of October, 2007.

Statutory Authority: Sections 386.210.2 and 386.250 RSMo 2000.

Executive Order 93-13 requires state agencies to undertake a "takings analysis" of each proposed rulemaking in light of the United States Supreme court decision in *Lucas v. South Carolina Coastal Council,* 112 S. Ct. 2886 (1992). Pursuant to that order, I have undertaken a "takings analysis" of the above-referenced proposed rulemaking. In *Lucas,* the Court held that state regulation depriving an owner of real property of all economically beneficial use of that property constitutes a "taking" under the Fifth and Fourteenth Amendments of the U.S. Constitution, for which the property owner must be compensated. Adopting the proposed rulemaking does not implicate the takings clause of the U.S. Constitution, because the proposed rulemaking does not involve the taking of real property.

Section 536.300, RSMo Supp. 2006, requires state agencies to "determine whether the proposed rule amendments affect small businesses and, if so, the availability and practicability of less-restrictive alternatives that could be implemented to achieve the same results of the proposed rulemaking." Executive Order 03-15, which similarly addresses the impacts of rulemakings on small businesses, defines a small business to be "a for-profit enterprise consisting of fewer than one hundred full- or part-time employees" and elaborates that a proposed rule "affects" a small business if it "impose[s] any potential or actual requirement" that "will cause direct and significant economic burden upon a small business, or that is directly related to the formation, operation, or expansion of a small business." Section 536.300.3, RSMo Supp. 2006, in part, provides: "If the state agency determines that its proposed rule does not affect small business, the state agency shall so certify this finding in the transmittal letter to the secretary of state, stating that it has determined that such proposed rule will not have an economic impact on small business . . ."

Proposed amendments to 4 CSR 240-40.030 do not impose any requirement that "will cause direct and significant economic burden upon a small business, or that is directly related to the formation, operation, or expansion of a small business." The Commission certifies that is has determined that the proposed rule amendment will not have an economic impact on small businesses.

If there are any questions, please contact:

Colleen M. Dale, Secretary
Missouri Public Service Commission
200 Madison Street
P.O. Box 360
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(573) 751-4255
cully.dale@psc.mo.gov

BY THE COMMISSION

Colleen M. Dale
Secretary

AFFIDAVIT

PUBLIC COST

STATE OF MISSOURI)
)
COUNTY OF COLE)

I, Gregory A. Steinhoff, Director of the Department of Economic Development, first being duly sworn, on my oath, state that it is my opinion that the cost of proposed amendment, 4 CSR 240-40.030, is less than five hundred dollars in the aggregate to this agency, any other agency of state government or any political subdivision thereof.

Greg Steinhoff

Gregory A. Steinhoff
Director
Department of Economic Development

Subscribed and sworn to before me this 21st day of September, 2007, I am commissioned as a notary public within the County of COLE, State of Missouri, and my commission expires on 17 JULY 2011.

Annette Kehner

Notary Public

ANNETTE KEHNER
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 17, 2011
Commission Number: 07492656

Title 4 – Department of Economic Development
Division 240 – Public Service Commission
Chapter 40 – Gas Utilities and Gas Safety Standards

PROPOSED AMENDMENT

4 CSR 240-40.030 Safety Standards – Transportation of Gas by Pipeline. The Commission is amending sections (1), (3), (4), (5), (6), (7), (8), (9), (10), (11), (12), (13), (16), adding section (17) and amending Appendices A, B, C, E.

PURPOSE: This amendment proposes to amend the rule to conform to amendments of 49 CFR part 192, to clarify the rule, and to make editorial changes.

(1) General.

(A) *[~~Scope of rule~~]* **What Is the Scope of this Rule?** (192.1)

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

2. This rule does not apply to -

A. The gathering of gas *[~~on private property outside of~~]* -

(I) *[~~An area within the limits of any incorporated or unincorporated city, town, or village~~]* **Through a pipeline that operates at less than zero (0) psig (0 kPa)**; or

(II) *[~~Any designated residential or commercial area such as a subdivision, business or shopping center or community development~~]* **Through a pipeline that is not a regulated onshore gathering line (as determined in (1)(E))**; or

B. Any pipeline system that transports only petroleum gas or petroleum gas/air *[~~mixture~~]* **mixtures** to –

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

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

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

1. Abandoned means permanently removed from service;

2. Administrator means the Administrator of the *[~~Research and Special Programs Administration~~]* **Pipeline and Hazardous Materials Safety Administration** of the United States Department of Transportation *[~~or any person~~]* to whom authority in the matters **of pipeline safety** *[~~concerned has~~]* **have** been delegated by the Secretary of the United States Department of Transportation, **or his or her delegate**;

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

4. Commission means the Missouri Public Service Commission *[~~, and designated~~]* ;

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

6. Designated commission personnel means the Pipeline Safety Program Manager at the address contained in 4 CSR 240-40.020(5) for required correspondence;

[~~5.~~] **7.** Distribution line means a pipeline other than a gathering or transmission line *[~~, and feeder~~]*;

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

[~~6.~~] **9.** 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;

[~~7.~~] **10.** Fuel line means the customer-owned gas piping downstream from the outlet of the customer meter or operator-owned pipeline, whichever is farther downstream;

[~~8.~~] **11.** Gas means natural gas, flammable gas, manufactured gas, or gas which is toxic or corrosive;

[~~9.~~] **12.** Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main;

[~~10.~~] **13.** 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;

[~~11.~~] **14.** 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;

[~~12.~~] **15.** Listed specification means a specification listed in subsection I. of Appendix B, **which is included herein (at the end of this rule)**;

[~~13.~~] **16.** *[~~Low pressure~~]* **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;

[~~14.~~] **17.** Main means a distribution line that serves as a common source of supply for more than one (1) service line;

[~~15.~~] **18.** Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of one (1) year;

[~~16.~~] **19.** Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this rule;

[~~17.~~] **20.** Municipality means a city, village or town;

[~~18.~~] **21.** Operator means a person who engages in the transportation of gas *[~~, and person~~]*;

22. 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;

[~~19.~~] **23.** 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) guage at 100°F (38°C);

[~~20.~~] **24.** Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders;

[~~21.~~] 25. 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;

[~~22.~~] 26. Pipeline facility means new and existing pipeline, 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;

[~~23.~~] 27. Reading means the highest sustained reading when testing in a bar hole or opening without induced ventilation;

[~~24.~~] 28. Service line means a distribution line that transports gas from a common source of supply to *[~~a) a customer meter or the connection to a customer's piping, whichever is farther downstream, or b) the connection to a customer's piping if there is no customer meter. A customer meter is the meter that measures the transfer of gas from an operator to a consumer~~]* **an individual customer, to two 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;**

29. 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 customer or multiple customers through a meter header or manifold;

[~~25.~~] 30. 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]);

[~~26.~~] 31. Sustained reading means the reading taken on a combustible gas indicator unit after adequately venting the test hole or opening;

[~~27.~~] 32. 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;

[~~28.~~] 33. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas in Missouri;

[~~29.~~] 34. Tunnel means a subsurface passageway large enough for a man to enter;

[~~30.~~] 35. Vault or manhole means a subsurface structure that a man can enter; and

[~~31.~~] 36. Yard line means an underground fuel line that transports gas from the service line to the customer's building. If multiple buildings are being served, building shall mean the building nearest to the connection to the service line. For purposes of this definition, if aboveground fuel line piping at the meter location is located within five feet (5') of a building being served by that meter, it

shall be considered to the customer's building and no yard line exists. At meter locations where aboveground fuel line piping is located greater than five feet (5') from the building(s) being served, the underground fuel line from the meter to the entrance into the nearest building served by that meter shall be considered the yard line and any other lines are not considered yard lines.

(D) Incorporation By Reference **<u>of the Federal Regulation at 49 CFR 192.7</u>**. (192.7)

[~~1. Any documents or portions of them incorporated by reference in this rule are included in this rule as though set out in full. When only a portion of a document is incorporated by reference, the remainder is not incorporated in this rule.~~

~~2. All incorporated documents are available for inspection in the offices of the Missouri Public Service Commission, Truman State Office Building, 301 W. High, Jefferson City, Missouri. In addition, the documents are available at the addresses in Appendix A.~~

~~3. The full titles for the publications incorporated by reference in this rule are provided in Appendix A to this rule. Numbers in parentheses indicate applicable editions. Earlier editions of documents or editions of documents formerly listed in previous editions of Appendix A may be used for materials and components manufactured, designed or installed in accordance with those earlier editions at the time they were listed. The user must refer to the appropriate previous edition of 49 CFR part 192 for a listing of the earlier listed editions or documents.~~]

<u>1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2006, and the subsequent Amendment 192-103 (published in *Federal Register* on February 1, 2007, page 72 FR 4655), 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.</u>

<u>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, 2006 version of 49 CFR part 192 is available at www.access.gpo.gov/nara/cfr/cfr-table-search.html. The *Federal Register* publication on page 72 FR 4655 is available at www.gpoaccess.gov/fr/advanced.html.</u>

<u>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 in the U.S. Department of Transportation - Pipeline and Hazardous Materials Safety Administration, 400 Seventh Street, SW., Washington, DC, or at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202-741-6030 or 866-272-6272. In addition, the incorporated materials are available from the respective organizations listed in 49 CFR 192.7.</u>

<u>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 2007 amendment of this rule. As of the 2007 amendment, Appendix A to this rule is also "Reserved" and included herein.</u>

(E) Gathering Lines. (**192.8 and** 192.9) *[~~Except as provided in subsections (1)(A) and (4)(HH), each operator of a gathering line must comply with the requirements of this rule applicable to transmission lines.~~]*

1. As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2006, 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, 2006 version of 49 CFR part 192 is available at www.access.gpo.gov/nara/cfr/cfr-table-search.html.

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.

(G) *[~~General.~~]* **What General Requirements Apply to Pipelines Regulated under this Rule?** (192.13)

1. No person may operate a segment of pipeline *[~~that is readied for service after March 12, 1971~~]* **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 line to which 49 CFR 192.8 and 192.9 did not apply until April 14, 2006 (see (1)(E))	**March 15, 2007**
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 *[~~November 12, 1970,~~]* **the date in the second column**, unless that replacement, relocation or change has been made *[~~in accordance with~~]* **according to the requirements in** this rule.

Pipeline	**Date**
Regulated onshore gathering line to which 49 CFR 192.8 and 192.9 did not apply until April 14, 2006 (see (1)(E))	**March 15, 2007**
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) – *[~~(16)~~]* **(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)3., 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. 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 *[~~paragraph (1)(B)21.~~]* **subsection (1)(B)**, such as a service line or main.

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

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

(J) Filing of Required Plans, Procedures and Programs. Each operator shall *[~~file with~~]* **submit to** designated commission personnel all plans, procedures and programs required by this rule (to include welding and joining procedures, construction standards, corrosion control procedures, *[~~replacement programs, operating and maintenance plans,~~]* damage prevention program*[~~s and~~]*, emergency *[~~plans~~]* **procedures, public education program, operator qualification program, replacement programs, transmission integrity management program, and procedural manual for operations, maintenance, and emergencies**). In addition, each change must be *[~~filed with~~]* **submitted to** designated commission personnel within twenty (20) days after the change is made.

(3) Pipe Design.

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

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

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

(I) Design of Plastic Pipe. (192.121) Subject to the limitations of subsection (3)(J), the design pressure for plastic pipe is determined in accordance with either of the following formulas:

$$P = 2S \frac{t}{(D-t)} \times 0.32$$

$$P = \frac{2S}{(SDR-1)} \times 0.32$$

where

P = Design pressure, psi (kPa) gauge;

S = For thermoplastic pipe, the *[~~long-term hydrostatic strength~~]* **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) *[, ~~psi (kPa)~~]*. **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–**

3/2004, *HDB/PDB/SDB/MRS Policies* (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D));

t = Specified wall thickness, in (mm);

D = Specified outside diameter, in (mm); 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.

(J) Design Limitations for Plastic Pipe. (192.123)

1. The design pressure may not exceed a gauge pressure of 100 psi (689 kPa) gauge for plastic pipe used in -

A. Distribution systems; or

B. Classes 3 and 4 locations.

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

A. 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

B. Above the following applicable temperatures for thermoplastic pipe, the temperature at which the *[~~long-term hydrostatic strength~~]* **HDB** used in the design formula under subsection (3)(I) is determined. *[~~However, if the pipe was manufactured before May 18, 1978, and its long-term hydrostatic strength was determined at 73°F (23°C), it may be used at temperatures up to 100°F (38°C).~~]*

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

(4) Design of Pipeline Components.

(B) General Requirements. (192.143)

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

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

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

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

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

A. Pressure testing;

B. Materials; and

C. Pressure and temperature ratings.

(D) Valves. (192.145)

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

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

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

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

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

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

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

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

4. No valve having shell components made of ductile iron may be used at pressures exceeding eighty percent (80%) of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to eighty percent (80%) of the pressure ratings for comparable steel valves at their listed temperature, if -

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

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

C. No valve having pressure containing parts made of ductile iron may be used in the gas pipe components of compressor stations.

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

1. Except as provided in paragraphs (4)(HH)2. and (4)(HH)3., each new *[~~or replacement segment of a~~]* 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. *[~~For the purposes of this subsection, replacement segment means the actual replaced line pipe, valve, fitting, or other line component.~~]*

2. This subsection does not apply to -

A. Manifolds;

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

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

D. Cross-overs;

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

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

G. Other piping that, under *[~~section 190.9 of 49 CFR part 190~~]* **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 *[~~section 190.9 of 49 CFR part 190~~]* **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.

(5) Welding of Steel in Pipelines.

(C) *[~~Qualification of~~]* Welding Procedures. (192.225)

1. *[~~Each welding procedure must be qualified under section IX of the ASME Boiler and Pressure Vessel Code or section 2 of API Standard 1104, whichever is appropriate to the function of the weld, except that a welding procedure qualified under an earlier edition previously listed in Appendix A to 49 CFR Part 192 may continue to be used but may not be requalified under the earlier edition.~~]* **Welding must be performed by a qualified welder in accordance with welding procedures qualified under section 5 of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)) or section IX of the ASME Boiler and Pressure Vessel Code "Welding and Brazing Qualifications" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)) to produce welds meeting the requirements of section (5) of this rule. A welding procedure qualified under an earlier edition of a standard listed in 49 CFR 192.7 (see (1)(D)) may continue to be used, but may not be requalified under the earlier edition. The quality of the test welds used to qualify welding procedures shall be determined by destructive testing in accordance with the applicable welding standard.**

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

(D) Qualification of Welders. (192.227)

1. Except as provided in paragraph (5)(D)2. *[~~of this rule~~]*, each welder must be qualified in accordance with section *[3]* **6** of API Standard 1104 **(incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))** or section IX of the ASME Boiler and Pressure Vessel Code **(incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**. However, a welder qualified under an earlier edition **of a standard** than listed in *[~~Appendix A~~]* **49 CFR 192.7 (see (1)(D))** may weld but may not requalify under that earlier edition.

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

(E) Limitations on Welders. (192.229)

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

2. No welder may weld with a particular welding process unless, within the preceding six (6) calendar months, s/he has engaged in welding with that process.

3. A welder qualified under paragraph (5)(D)1. -

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 has had one (1) weld tested and found acceptable under *[~~section 3 or 6 of API Standard 1104, except that a~~]* **the sections 6 or 9 of API Standard 1104 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)). Alternatively, welders 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 (7½) months. A** welder qualified under an earlier edition *[~~previously~~]* **of a standard** listed in *[~~Appendix A to 49 CFR Part 192~~]* **49 CFR 192.7 (see (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 is tested in accordance with subparagraph (5)(E)3.A. or requalifies under subparagraph (5)(E)4.A. or B.

4. A welder 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 has requalified under paragraph (5)(D)2.; or

B. Within the preceding seven and one-half (7½) calendar months, but at least twice each calendar year, the welder has had -

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

(II) For welders who work 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.

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

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

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

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

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

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

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

3. The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section *[6]* **9** of API Standard 1104 **(incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if *[~~the~~]* Appendix **A** to API Standard 1104 applies to the weld, the acceptability of the weld may be further determined under that Appendix.

(6) Joining of Materials Other Than by Welding.

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

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

A. The burst test requirements of -

(I) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Pressure *[[~~Quick Burst~~]]*) **or paragraph 8.9 (Sustained Static Pressure Test)** of ASTM D2513 **(incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**;

(II) *[~~In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Tests) of ASTM D2517~~]* **(Reserved)**; or

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

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

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

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

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

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

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

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

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

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

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

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

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

(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 paragraphs (6)(G)1. (192.283[a]) 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 if during any twelve (12)-month period that person.

A. Does not make any joints under that procedure; or

B. Has three (3) joints or three percent (3%) of the joints made, whichever is greater, under that procedure that are 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 *[~~his/her~~]* **the operator's** system is qualified in accordance with this subsection.

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

(K) Installation of Plastic Pipe. (192.321)

1. Plastic pipe must be installed below ground level *[~~unless otherwise permitted by paragraph (7)(K)7.~~]* **except as provided by paragraphs (7)(K)7. and (7)(K)8.**

2. Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gastight metal pipe and fittings that are adequately protected from corrosion.

3. Plastic pipe must be installed so as to minimize shear or tensile stresses.

4. Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (0.090") (2.29 millimeters), except that pipe with an outside diameter of 0.875 inches (0.875") (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inches (0.062") (1.58 millimeters).

5. Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground. **Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.**

6. Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

7. Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

A. The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or two (2) years, whichever is less;

B. The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage; and

C. The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

8. Plastic pipe may be installed on bridges provided that it is:

A. Installed with protection from mechanical damage, such as installation in a metallic casing;

B. Protected from ultraviolet radiation; and

C. Not allowed to exceed the pipe temperature limits specified in subsection (3)(J).

(N) Cover. (192.327)

1. Except as provided in paragraphs (7)(N)3. and 5., each buried transmission line must be installed with a minimum cover as follows:

Location	Normal Soil	Consolidated Rock
	inches (millimeters)	
Class 1 locations	30 (762)	18 (457)
Class 2, 3 and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

2. Except as provided in paragraphs (7)(N)3. and 4., each buried main must be installed with at least twenty-four inches (24") (610 millimeters) of cover.

3. Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

4. A main may be installed with less than twenty-four inches (24") (610 millimeters) of cover if the law of the state or municipality.

A. Establishes a minimum cover of less than twenty-four inches (24") (610 millimeters);

B. Requires that mains be installed in a common trench with other utility lines; and

C. Provides adequately for prevention of damage to the pipe by external forces.

5. Except as provided in paragraph *~~[(7)(N)3.]~~* **(7)(N)3.,** all pipe installed in a navigable river, stream or harbor must be installed with a minimum cover of forty-eight inches (48") (1219 millimeters) in soil or twenty-four inches (24") (610 millimeters) in consolidated rock between the top of the pipe and the **underwater** natural bottom **(as determined by recognized and generally accepted practices)**.

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

(C) Customer Meters and Regulators - Location. (192.353)

1. Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion~~[, anticipated vehicular traffic]~~ and other damage, **including, if installed outside a building, vehicular damage that may be anticipated.** However, the upstream regulator in a series may be buried.

2. Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

3. Each meter installed within a building must be located in a ventilated place and not less than three feet (3') (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

4. Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

(G) Service Lines - Installation. (192.361)

1. Depth. Each buried service line must be installed with at least twelve inches (12") (305 millimeters) of cover in private property and at least eighteen inches (18") (457 millimeters) of cover in streets and roads, except a plastic service line that is not inserted in a metallic casing must be installed with at least eighteen inches (18") (457 millimeters) of cover in all locations. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

2. Support and backfill. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

3. Grading for drainage. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

4. Protection against piping strain and external loading. Each service line must be installed so as to minimize anticipated piping strain and external loading.

5. Installation of service lines into buildings. Each underground service line installed below grade through the outer foundation wall of a building must.

A. In the case of a metal service line, be protected against corrosion;

B. In the case of a plastic service line, be protected from shearing action and backfill settlement; and

C. Be sealed at the foundation wall to prevent leakage into the building.

6. Installation of service lines under buildings. Where an underground service line is installed under a building.

A. It must be encased in a gastight conduit;

B. The conduit and the service line must extend, if the service line supplies the building it underlies, into a normally usable and accessible part of the building; and

C. The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

7. Locating underground service lines. Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with paragraph (7)(K)5.

(M) Service Lines - Plastic. (192.375)

1. Each plastic service line outside a building must be installed below ground level, except that -

A. It may be installed in accordance with paragraph (7)(K)7.; and

B. It may terminate aboveground level and outside the building, if -

(I) The aboveground level part of the plastic service line is protected against deterioration and external damage; and

(II) The plastic service line is not used to support external loads.

2. Plastic service lines shall not be installed inside a building.

3. Plastic pipe that is installed in a below grade vault or pit must be completely encased in gastight metal pipe and fittings that are adequately protected from corrosion.

4. Plastic pipe must be installed so as to minimize shear or tensile stresses.

5. Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (0.090"), except that pipe with an outside diameter of 0.875 inches (0.875") or less may have a minimum wall thickness of 0.062 inches (0.062").

[~~6. Plastic pipe that is not encased must have an electrically conductive wire or other means of locating the pipe while it is underground.~~]

[~~7~~] **6.** Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic must be closed before insertion.

(9) Requirements for Corrosion Control.

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

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

2. Regulated onshore gathering lines. For any regulated onshore gathering line to which 49 CFR 192.8 and 192.9 did not apply until April 14, 2006, and for any gathering line that becomes a regulated onshore gathering line under (1)(E) because of a change in class location or increase in dwelling density:

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

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

(E) External Corrosion Control - Buried or Submerged Pipelines Installed Before August 1, 1971. (192.457)

1. Each buried or submerged transmission line and each buried or submerged feeder line or main in excess of one hundred feet (100') installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this section unless definitely scheduled in a replacement program in subsection (15)(E). For the purposes of this section, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

2. Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must be cathodically protected in accordance with this section in areas in which active corrosion is found:

A. Bare or ineffectively coated transmission lines;

B. Effectively coated feeder lines and mains not in excess of one hundred feet (100');

C. Bare or ineffectively coated feeder lines or mains; and

D. Bare or coated service lines, except that steel service lines must be replaced as required by subsection (15)(C).

[~~The operator shall determine the areas of active corrosion by electrical survey. Where electrical survey is impractical, the areas of active corrosion shall be determined by the study of corrosion and leak history records, and by instrument leak detection survey. After this initial evaluation for areas of active corrosion, each operator must conduct reevaluations as required by paragraph (9)(I)5.~~

~~3. For the purpose of this section, active corrosion means continuing corrosion which, unless controlled, could result in a condition that is detrimental to public safety.~~]

(H) External Corrosion Control – Cathodic Protection. (192.463)

1. Each cathodic protection system required by this section must provide a level of cathodic protection that complies with one (1) or more of the applicable criteria contained in Appendix D, **which is included herein (at the end of this rule)**.

2. If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential –

A. The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

B. The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D for amphoteric metals.

3. The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

(I) External Corrosion Control - Monitoring. (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') (30 meters), 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') (30meters) in length installed and cathodically protected in accordance with paragraph (9)(R)2. (192.483[b]), each segment of pipe cathodically protected in accordance with paragraph (9)(R)3. (192.483[c]) and each electrically isolated metallic fitting not meeting the requirements of paragraph (9)(D)5. (192.455[f]) must be monitored at a minimum rate of ten percent (10%) each calendar year, with a different ten percent (10%) checked each subsequent year, so that the entire system is tested every ten (10) years.

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

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

4. Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring required 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 *[~~paragraph~~]* **paragraphs** (9)(D)2. and *[~~paragraph~~]* (9)(E)2., each operator *[~~, at intervals not exceeding three (3) years, shall~~]* **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 *[~~this~~]* section **(9)** in areas in which active corrosion is found, except that unprotected steel service lines must be replaced as required by subsection (15)(C). The operator *[~~shall~~]* **must** determine the areas of active corrosion by electrical survey *[~~at intervals not exceeding three (3) years. Where~~]*. **However, on distribution lines and where an** electrical survey is impractical **on transmission lines,** *[~~the~~]* areas of active corrosion *[~~shall~~]* **may** be determined by *[~~the study of corrosion and leak history records~~]* **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 *[~~survey at intervals not exceeding three (3) years~~]* **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. **In this subsection and subsection (9)(E):**

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

B. Electrical survey means a series of closely spaced pipe-to-soil readings over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

C. 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.

(N) Internal Corrosion Control – General **and Monitoring**. (192.475 **and 192. 477**)

1. Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

2. Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found -

A. The adjacent pipe must be investigated to determine the extent of internal corrosion;

B. Replacement must be made to the extent required by the applicable paragraphs of subsections (9)(S), (T) or (U) (192.485, 192.487 or 192.489); and

C. Steps must be taken to minimize the internal corrosion.

3. Gas containing more than 0.25 grain of hydrogen sulfide per one hundred (100) cubic feet (5.8 milligrams/m3) at standard conditions (four (4) parts per million) may not be stored in pipe-type or bottle-type holders.

4. Monitoring. (192.477) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two (2) times each calendar year, but with intervals not exceeding seven and one-half (7 1/2) months.

(O) Internal Corrosion Control – *[~~Monitoring. (192.477) If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two (2) times each calendar year, but with intervals not exceeding seven and one-half (7 1/2) months.~~]* **Design and Construction of Transmission Line. (192.476)**

1. Design and construction. Except as provided in paragraph (9)(O)2., each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

A. Be configured to reduce the risk that liquids will collect in the line;

B. Have effective liquid removal features whenever the configuration would allow liquids to collect; and

C. Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

2. Exceptions to applicability. The design and construction requirements of paragraph (9)(O)1. do not apply to pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

3. Change to existing transmission line. When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

4. Records. An operator must maintain records demonstrating compliance with this subsection. Provided the records show why incorporating design features addressing (9)(O)1.A., (9)(O)1.B., or ((9)(O)1.C. is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

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

1. Pipeline installed after July 31, 1971. Each aboveground pipeline or portion of a pipeline installed after July 31, 1971, that is exposed to the atmosphere must be cleaned and *[~~either~~]* coated *[~~or jacketed~~]* with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph for an inside pipeline, if the operator can demonstrate by test, investigation or experience *[~~in the area of application, that a corrosive atmosphere does not exist.~~]* **appropriate to the inside environment of the pipeline that corrosion will -**

A. Only be a light surface oxide; or

B. Not result in pitting of the base metal before the next scheduled inspection.

2. Pipelines installed before August 1, 1971. Each *[~~operator having an~~]* above-ground pipeline or portion of a pipeline installed before August 1, 1971, that is exposed to the atmosphere *[~~, shall -~~]*

~~A. Determine the areas of atmospheric corrosion on the pipeline;~~

~~B. If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of subsections (9)(S), (T), or (U); and~~

~~C. Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline~~] **must be cleaned and coated** with a material suitable for the prevention of atmospheric corrosion. **This applies to all portions of pipelines in soil-to-air interfaces. For portions of pipelines that are not in soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will -**

A. Only be a light surface oxide; or

B. Not affect the safe operation of the pipeline before the next scheduled inspection.

3. For the purposes of this *[~~section~~]* **subsection and subsection (9)(Q)**, atmospheric corrosion means corrosion that has resulted in pitting of the base metal.

(Q) Atmospheric Corrosion Control - Monitoring. (192.481) *[~~After meeting the requirements of paragraphs (9)(P)1. and 2 (192.479[a] and [b], each operator, at intervals not exceeding three (3)~~*

~~*years, shall reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion. When remedial action is necessary, corrective actions must be completed within twelve (12) months unless otherwise approved by designated commission personnel.*~~*]*

1. Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion at least once every three (3) calendar years, but with intervals not exceeding thirty-nine (39) months. (Atmospheric corrosion is defined in paragraph (9)(P)3.)

2. During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, at deck penetrations, and in spans over water.

3. If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by subsection (9)(P) within twelve (12) months unless otherwise approved by designated commission personnel.

(W) Direct Assessment. (192.490) **Each operator that uses direct assessment as defined in 49 CFR 192.903 (see section (16)) on a transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.**

Threat	**Standard[1] (see section (16))**
External corrosion	**49 CFR 192.925[2]**
Internal corrosion in pipelines that transport dry gas.	**49 CFR 192.927**
Stress corrosion cracking	**49 CFR 192.929**

[1]For lines not subject to 49 CFR part 192, subpart O, the terms "covered segment" and "covered pipeline segment" in 49 CFR 192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed.

[2]In 49 CFR 192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to 49 CFR part 192, subpart O.

(10) Test Requirements.

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

1. Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of thirty percent (30%) or more of SMYS must be strength tested in accordance with this subsection to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within three hundred feet (300') (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least one hundred

twenty-five percent (125%) of maximum operating pressure on that segment of the pipeline within three hundred feet (300') (91 meters) of such a building, but in no event may the test section be less than six hundred feet (600') (183 meters) unless the length of the newly installed or relocated pipe is less than six hundred feet (600') (183 meters). However, if the buildings are evacuated while the hoop stress exceeds fifty percent (50%) of SMYS, air or inert gas may be used as the test medium.

2. In a Class 1 or Class 2 location, each compressor station, regulator station and measuring station must be tested to at least Class 3 location test requirements.

3. Except as provided in paragraph (10)(C)5., the strength test must be conducted by maintaining the pressure at or above the test pressure for at least eight (8) hours.

4. If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that -

A. The component was tested to at least the pressure required for the pipeline to which it is being added; *[~~or~~]*

B. The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; **or**

C. The component carries a pressure rating established through applicable ASME/ANSI, MSS specifications, or by unit strength calculations as described in subsection (4)(B).

5. For fabricated units and short sections of pipe, for which a post-installation test is impractical, a pre-installation strength test must be conducted by maintaining the pressure at or above the test pressure for at least four (4) hours.

(11) Uprating.

(B) General Requirements. (192.553)

1. Pressure increases. Whenever the requirements of this section require that an increase in operating pressure be made in increments, the pressure must be increased gradually, at a rate that can be controlled and in accordance with the following:

A. At the end of each incremental increase, the pressure must be held constant while the entire segment of the pipeline that is affected is checked for leaks. When a combustible gas is being used for uprating, all buried piping must be checked with a leak detection instrument after each incremental increase; and

B. Each leak detected must be repaired before a further pressure increase is made, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous.

2. Records. Each operator who uprates a segment of pipeline shall retain for the life of the segment a record of each investigation required by this section, of all work performed, and of each pressure test conducted, in connection with the uprating.

3. Written plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure compliance with each applicable requirement of this section.

4. Limitation on increase in maximum allowable operating pressure. Except as provided in (11)(C)3., a new maximum allowable operating pressure established under this section may not exceed the maximum that would be allowed under *[~~this rule~~]* **(12)(M) and (12)(N)** for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula in subsection (3)(C) is unknown, the MAOP may be increased as provided in subparagraph (12)(M)1.A.

5. Establishment of a new maximum allowable operating pressure. Subsections (12)(M) and (N) (192.619 and 192.621) must be reviewed when establishing a new MAOP. The pressure to which the pipeline is raised during the uprating procedure is the test pressure that must be divided by the appropriate factors in subparagraph (12)(M)1.B. (192.619[a][2]) except that pressure tests conducted on steel and plastic pipelines after July 1, 1965 are applicable.

(12) Operations.

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

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

2. Maintenance and normal operations. The manual required by paragraph (12)(C)1. must include procedures for the following *[~~where applicable for an operator's facilities~~]* **, if applicable,** to provide safety during maintenance and normal operations:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

M. Testing and inspecting of customer-owned gas piping and equipment*[~~.~~]* ; **and**

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

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

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

(I) Unintended closure of valves or shutdowns;

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

(III) Loss of communications;

(IV) Operation of any safety device; and

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

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

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

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

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

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

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

(D) Qualification of Pipeline Personnel.

1. Scope. (192.801)

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

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

(I) Is performed on a pipeline facility;

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

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

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

2. Definitions. (192.803)

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

(I) Indicate a condition exceeding design limits;

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

(III) Require an emergency response.

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

(I) Written examination;

(II) Oral examination;

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

(a) Performance on the job;

(b) On the job training; or

(c) Simulations.

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

(I) Perform assigned covered tasks; and

(II) Recognize and react to abnormal operating conditions.

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

A. Identify covered tasks;

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

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

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

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

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

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

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

I. Ensure that covered tasks are:

(I) Performed by qualified individuals; or

(II) Directed and observed by qualified individuals *[.]*; **and**

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

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

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

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

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

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

E. Recognize potential ignition sources;

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

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

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

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

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

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

8. *[~~Record keeping~~]* **Recordkeeping.** (192.807) Each operator shall maintain records that demonstrate compliance with this subsection.

A. Qualification records shall include:

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

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

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

(IV) Qualification method(s).

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

9. General. (192.809)

A. Subsection (12)(D) for personnel qualification was promulgated in 1989, effective December 15, 1989. Operators were required to meet the training and testing requirements within eighteen (18) months following the effective date, or June 15, 1991. At that time, there were no federal requirements for personnel qualification.

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

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

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

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

(G) Change in Class Location — Confirmation or Revision of Maximum Allowable Operating Pressure. (192.611) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one (1) of the following three (3) paragraphs:

1. If the segment involved has been previously tested in place for a period of not less than eight (8) hours, the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed seventy-two percent (72%) of SMYS of the pipe in Class 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of SMYS in Class 4 locations;

2. The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this rule for new segments of pipelines in the existing class location; or

3. The segment of pipeline involved must be tested in accordance with the applicable requirements of section (10), and its maximum allowable operating pressure must then be established according to the following criteria:

A. The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations and 0.555 times the test pressure for Class 4 locations; and

B. The corresponding hoop stress may not exceed seventy-two percent (72%) of the SMYS of the pipe in Class 2 locations, sixty percent (60%) of SMYS in Class 3 locations or fifty percent (50%) of the SMYS in Class 4 locations.

4. The maximum allowable operating pressure confirmed or revised in accordance with this subsection may not exceed the maximum allowable operating pressure established before the confirmation or revision.

5. Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this subsection does not preclude the application of subsections (11)(B) and (C) (192.553 and 192.555).

6. Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under subsection (12)(F) must be completed within *[~~eighteen (18)~~]* **<u>twenty-four (24)</u>** months of the change in class location. Pressure reduction under paragraph (12)(G)1. or 2. within the

[~~eighteen (18)~~] **twenty-four (24)**-month period does not preclude establishing a maximum allowable operating pressure under paragraph (12)(G)3., at a later date.

(K) Public *[~~Education~~]* **Awareness.** (192.616)

1. *[~~Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area. The~~]* **Each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)). In addition, the** program must provide for notification of the intended groups on the following schedule:

[~~1.~~] **A.** Appropriate government organizations and persons engaged in excavation related activities must be notified at least annually;

[~~2.~~] **B.** The public must be notified at least semiannually; and

[~~3.~~] **C.** Customers must be notified at least semiannually by mailings or hand-delivered messages and at least nine (9) times a calendar year by billing messages.

2. The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

3. The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

4. The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

A. Use of a one-call notification system prior to excavation and other damage prevention activities;

B. Possible hazards associated with unintended releases from a gas pipeline facility;

C. Physical indications that such a release may have occurred;

D. Steps that should be taken for public safety in the event of a gas pipeline release; and

E. Procedures for reporting such an event.

5. The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

6. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

7. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

8. Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. As an exception, master meter operators having less than twenty-five (25) customers must have completed development and documentation of their programs no later than June 20, 2007. Operators must submit their completed programs and any program changes to designated commission personnel as required by subsection (1)(J).

9. The operator's program documentation and evaluation results must be available for periodic review by designated commission personnel.

(M) Maximum Allowable Operating Pressure - Steel or Plastic Pipelines. (192.619)

1. Except as provided in paragraph (12)(M)3., 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 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 *[N5.0]* **N5** of Appendix N of ASME B31.8 **(incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**, reduced by the appropriate factor in (12)(M)1.B.(II); or

(II) If the pipe is twelve and three-quarter inches (12¾") (324 mm) or less in outside diameter and is not tested to yield under this paragraph, two hundred (200) psi (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 (689 kPa) gauge or more, the test pressure is divided by a factor determined in accordance with the following table:

	Factors[1], segment -		
Class Location	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under subsection (1)(H) (192.14)
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

C. The highest actual operating pressure to which the segment was subjected during the five (5) years preceding *[~~July 1, 1970~~,]* **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

[~~July 1, 1965,~~] **<u>the applicable date in the third column</u>** or the segment was uprated in accordance with section (11); *~~[and]~~*

<u>Pipeline Segment</u>	**<u>Pressure Date</u>**	**<u>Test date</u>**
<u>Onshore gathering line that first became subject to 49 CFR 192.8 and 192.9 after April 13, 2006 (see (1)(E)).</u>	**<u>March 15, 2006, or date line becomes subject to this rule, whichever is later.</u>**	**<u>5 years preceding applicable date in second column.</u>**
<u>Onshore transmission line that was a gathering line not subject to 49 CFR 192.8 and 192.9 before March 15, 2006 (see (1)(E)).</u>	**<u>March 15, 2006</u>**	**<u>March 15, 2001</u>**
<u>All other pipelines.</u>	**<u>July 1, 1970</u>**	**<u>July 1, 1965</u>**

D. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating 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. *[~~Notwithstanding the other requirements of this subsection, 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 July 1, 1970, subject to the requirements of subsection (12)(G).~~]* **<u>The requirements on pressure restrictions in this subsection do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the five (5) years preceding the applicable date in the second column of the table in (12)(M)1.C. An operator must still comply with (12)(G).</u>**

(P) Odorization of Gas. (192.625)

1. A combustible gas in a transmission line or distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth (1/5) of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell. However, for transmission lines in operation before May 28, 1995, the section of transmission line between the supplier's delivery point and the odorizer need not meet the requirements of this paragraph.

2. For installations made after May 28, 1995, a combustible gas in a transmission line must comply with the requirements of paragraph (12)(P)1., and the odorizer must be located as close as practical to the delivery point from the supplier.

3. In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

A. The odorant may not be deleterious to persons, materials or pipe; and

B. The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

4. The odorant may not be soluble in water to an extent greater than two and one-half (2 1/2) parts to one hundred (100) parts by weight.

5. Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

6. **To assure the proper concentration of odorant in accordance with this subsection,** *[~~E~~]*each operator *[~~shall~~]* **must** conduct, at least monthly, odor intensity tests with an instrument *[~~to assure the proper concentration of odorant and odorant intensity in accordance with this subsection.~~]* **capable of determining the percentage of gas in air at which the odor becomes readily detectable.** At individually odorized service lines, the odor intensity shall be checked at least once each calendar year at intervals not to exceed fifteen (15) months. Operators of master meter systems may comply with this paragraph by -

A. Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

B. Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

7. All odorant tanks should be checked periodically to assure adequate odorant is available. Odorant injection rates can be a useful monitoring tool for some systems. Each operator should consider when and where to use odorant injection rates.

(13) Maintenance.

(F) Recordkeeping. (192.709)

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

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

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

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

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

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

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

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

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

1. Each operator shall perform abandonment or deactivation of pipelines in accordance with the requirements of this subsection.

2. Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

3. Except for service lines, each inactive pipeline that is not being maintained under this rule must be disconnected from all sources and supplies of gas, purged of gas and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

4. Whenever service to a customer is discontinued, one (1) of the following must be complied with:

A. The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator;

B. A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly; or

C. The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

5. If air is used for purging, the operator shall ensure that a combustible mixture is not present after purging.

6. Each abandoned vault must be filled with a suitable compacted material.

7. For each abandoned pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. The addresses (mail and e-mail) and phone numbers given in this paragraph are from *[~~section 192.727(g) of 49 CFR part 192, which became effective on October 10, 2000~~]* **49 CFR 192.727(g) as published on October 1, 2006**. Please consult the current edition of 49 CFR part 192 for any updates to these addresses and phone numbers.

A The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS ``Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at *[~~www.npms.rspa.dot.gov~~]* **www.npms.phmsa.dot.gov** or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Information Officer, *[~~Research and Special Programs Administration~~]* **Pipeline and Hazardous Materials Safety Administration, U.S.** Department of Transportation, Room *[~~7128~~]* **2103**, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, *[~~roger.little@rspa.dot.gov~~]* **roger.little@dot.gov**. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

B. *[~~Data on pipeline facilities abandoned before October 10, 2000 must be filed before April 10, 2001. Operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@rspa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.~~]* **(Reserved)**

(R) Pressure Limiting and Regulating Stations - Inspection and Testing. (192.727)

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

[~~1.~~] **A.** In good mechanical condition;

[~~2.~~] **B.** Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

[~~3.~~] **C.** *[~~Set~~]* **Except as provided in paragraph (13)(R)2., set** to control or relieve at the correct pressures that will prevent downstream pressures from exceeding the allowable pressures under subsections *[~~(4)(CC)~~]* **(4)(FF)**, (12)(M)-(O);

[~~4.~~] **D.** Properly installed and protected from dirt, liquids and other conditions that might prevent proper operation;

[~~5.~~] **E.** Properly protected from unauthorized operation of valves in accordance with paragraph (4)(EE)8.;

[~~6.~~] **F.** Equipped to indicate regulator malfunctions in accordance with paragraphs (4)(EE)10. and 11. in a manner that is adequate from the standpoint of reliability of operation; and

[~~7.~~] **G.** Equipped with adequate over-pressure protection in accordance with paragraph (4)(EE)9.

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

<u>A. If the MAOP produces a hoop stress that is greater than 72 percent of SMYS, then the pressure limit is MAOP plus 4 percent.</u>

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

(T) Pressure Limiting and Regulating Stations – *[~~Testing~~]* **<u>Capacity</u>** of Relief Devices. (192.743)

1. *[~~If feasible, pressure relief devices (except rupture discs) must be tested in place at intervals not exceeding fifteen (15) months but at least once each calendar year, to determine that they have enough~~]* **<u>Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in paragraph (13)(R)2., these devices must have sufficient</u>** capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure which does not exceed the pressure allowed by subsection (4)(FF). **<u>This capacity must be determined at intervals not exceeding fifteen (15) months, but at least once each calendar year, by testing the devices in place or by review and calculations.</u>**

2. *[~~If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding fifteen (15) months but at least once each calendar year, and these required capacities~~]* **<u>If review and calculations are used to determine if a relief device has sufficient capacity, the calculated capacity must be</u>** compared with the rated or experimentally determined relieving capacity of the device for the *[~~operating~~]* conditions under which it *[~~works~~]* **<u>operates</u>**. After the initial calculations, subsequent calculations *[~~are not required~~]* **need not be made** if the **annual** review documents that parameters have not changed *[~~in a manner which would cause the capacity to be less than required~~]* **<u>to cause the rated or experimentally determined relieving capacity to be insufficient</u>**.

3. If *[~~the relieving~~]* **<u>a relief</u>** device is of insufficient capacity *[~~to comply with subsection (4)(FF)~~]*, a new or additional device must be installed to provide the *[~~additional~~]* capacity required **<u>by paragraph (13)(T)1.</u>**

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

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

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

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

1. Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked for accessibility and serviced at intervals not exceeding fifteen (15) months but at least once each calendar year.

2. Feeder line and distribution line valves, the use of which may be necessary for the safe operation of a distribution system, shall be inspected at intervals not exceeding fifteen (15) months but at least once each calendar year. At a minimum, the valves that are metallic must be partially operated during alternating calendar years.

3. Valves necessary for the safe operation of a distribution system include, but are not limited to, those which provide:

A. One hundred percent (100%) isolation of the system or any portion of it;

B. Control of a district regulator station, preferably from a remote location;

C. Zones of isolation sized such that the operator could relight the lost customer services within a period of eight (8) hours after restoration of system pressure; or

D. Extensive zone isolation capabilities where historical records indicate conditions of greater than normal pipeline failure risk.

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

(Y) Caulked Bell and Spigot Joints. (192.753)

1. Each cast iron caulked bell and spigot joint that is subject to pressures of **more than** twenty-five (25) psi (172 kPa) gauge *[~~or more~~]* must be sealed with -

A. A mechanical leak clamp; or

B. A material or device which –

(I) Does not reduce the flexibility of the joint;

(II) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(III) Seals and bonds in a manner that meets the strength, environmental and chemical compatibility requirements of paragraphs (2)(B)1. and 2. and subsection (4)(B). (192.53(a) and (b) and 192.143)

2. Each cast iron caulked bell and spigot joint that is subject to pressures of *[~~less than~~]* twenty-five (25) psi (172 kPa) gauge **or less** and is exposed for any reason must be sealed by a means other than caulking.

(16) *[~~Waivers of Compliance.~~]* **Pipeline Integrity Management For Transmission Lines.** *[~~Upon written request to the secretary of the commission, the commission, by authority order, and under such terms and conditions as the commission deems appropriate, may waive in whole or part compliance with any of the rules and requirements contained in the rule which are more stringent than minimum federal requirements. Waivers will be granted only on a showing that gas safety is not compromised. If any such request is denied, the denial will be in writing and state the reason(s) therefor.~~]*

(A) As set forth in the *Code of Federal Regulations* (CFR) dated October 1, 2006, the subsequent Amendment 192-103 (published in *Federal Register* on February 1, 2007, page 72 FR 4655), and the subsequent amendment published on July 17, 2007 (published in *Federal Register* on July 17, 2007, page 72 FR 39012), the federal regulations in 49 CFR part 192, subpart O and in 49 CFR part 192, appendix E are incorporated by reference and made a part of this rule. This

rule does not incorporate any subsequent amendments to subpart O and appendix E to 49 CFR part 192.

(B) The *Code of Federal Regulations* and the *Federal Register* are published by the Office of the Federal Register, National Archives and Records Administration, 8601 Adelphi Road, College Park, MD 20740-6001. The October 1, 2006 version of 49 CFR part 192 is available at www.access.gpo.gov/nara/cfr/cfr-table-search.html. The *Federal Register* publications on page 72 FR 4655 and page 72 FR 39012 are available at www.gpoaccess.gov/fr/advanced.html.

(C) Subpart O and appendix E to 49 CFR part 192 contain the federal regulations regarding pipeline integrity management for transmission lines. Subpart O includes sections 192.901 through 192.951. Information regarding subpart O is available at http://primis.phmsa.dot.gov/gasimp.

(17) Waivers of Compliance. Upon written request to the secretary of the commission, the commission, by authority order and under such terms and conditions as the commission deems appropriate, may waive in whole or part compliance with any of the requirements contained in this rule. Waivers will be granted only on a showing that gas safety is not compromised. If the waiver request would waive compliance with a federal requirement in 49 CFR part 192, additional actions shall be taken in accordance with 49 USC 60118.

Appendix A – 4 CSR 240-40.030

[~~Appendix A – Incorporated by Reference~~] **(Reserved)**

[~~I. List of organizations and address.~~

~~A. American Gas Association (AGA), 1515 Wilson Boulevard, Arlington, VA 22209.~~

~~B. American National Standards Institute (ANSI), 11 West 42nd Street, New York, NY 10036.~~

~~C. American Petroleum Institute (API), 1220 L Street, N.W., Washington, D.C. 20005~~

~~D. The American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, N.Y. 10017.~~

~~E. American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, West Conshohocken, PA 19428.~~

~~F. Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park Street, N.W., Vienna, VA 22180.~~

~~G. National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, Massachusetts 02269-9101.~~

~~II. Documents incorporated by reference. Numbers in parentheses indicate applicable editions.~~

~~A. American Gas Association (AGA):~~

~~1) AGA Pipeline Research Committee, Project PR-3-805, A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (December 22, 1989).~~

~~B. American Petroleum Institute (API):~~

~~1) API Specification 5L Specification for Line Pipe (41st edition, 1995).~~

~~*2) API Recommended Practice 5L1 Recommended Practice for Railroad Transportation of Line Pipe (4th edition, 1990).*~~

~~*3) API Specification 6D Specification for Pipeline Valves (Gate, Plug, Ball, and Check Valves) (21st edition, 1994).*~~

~~*4) API Standard 1104 Welding of Pipelines and Related Facilities (18th edition, 1994).*~~

~~*C. The American Society for Testing and Materials (ASTM):*~~

~~*1) ASTM Designation A 53 Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless (A 53-96).*~~

~~*2) ASTM Designation A 106 Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service (A 106-95).*~~

~~*3) ASTM Designation A 671 Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures (A 671-94).*~~

~~*4) ASTM Designation A 672 Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures (A 672-94).*~~

~~*5) ASTM Designation A 691 Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures (A 691-93).*~~

~~*6) ASTM Designation A 333/A 333M Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service (A 333/A 333M-94).*~~

~~*7) ASTM Designation A 372/A 372M Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels (A 372/A 372M-95).*~~

~~*8) ASTM Designation A 381 Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems (A 381-93).*~~

~~*9) ASTM Designation D 638 Standard Test Method for Tensile Properties of Plastics (D 638-96).*~~

~~*10) ASTM Designation D 2513 Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings (D 2513-87 edition for subparagraph (2)(E)1.A., otherwise D 2513-96a).*~~

~~*11) ASTM Designation D 2517 Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings (D 2517-94).*~~

~~*12) ASTM Designation F 1055 Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing (F 1055-95).*~~

~~*D. The American Society of Mechanical Engineers (ASME):*~~

~~*1) ASME/ANSI B16.1 Cast Iron Pipe Flanges and Flanged Fittings (1989).*~~

~~*2) ASME/ANSI B16.5 Pipe Flanges and Flanged Fittings (1988 with October 1988 Errata and ASME/ANSI B16.5a-1992 Addenda).*~~

~~*3) ASME/ANSI B31G Manual for Determining the Remaining Strength of Corroded Pipelines (1991).*~~

~~*4) ASME/ANSI B31.8 Gas Transmission and Distribution Piping Systems (1995).*~~

~~*5) ASME Boiler and Pressure Vessel Code, Section I Power Boilers (1995 edition with 1995 Addenda).*~~

~~*6) ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 Pressure Vessels (1995 edition with 1995 Addenda).*~~

~~7) ASME Boiler and Pressure Vessel Code, Section VIII, Division 2 Pressure Vessels: Alternative Rules (1995 edition with 1995 Addenda).~~

~~8) ASME Boiler and Pressure Vessel Code, Section IX, Welding and Brazing Qualifications (1995 edition with 1995 Addenda).~~

~~E. Manufacturer's Standardization Society of the Valve and Fittings Industry, Inc. (MSS):~~

~~1) MSS SP-44-1996 Steel Pipe Line Flanges (includes 1996 errata) (1996).~~

~~F. National Fire Protection Association (NFPA):~~

~~1) ANSI/NFPA-30 Flammable and Combustible Liquids Code (1996).~~

~~2) Reserved.~~

~~3) ANSI/NFPA-58 Standard for the Storage and Handling of Liquefied Petroleum Gases (1995).~~

~~4) ANSI/NFPA-59 Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants (1995).~~

~~5) ANSI/NFPA-70 National Electrical Code (1996).~~]

Appendix B to 4 CSR 240-40.030
Appendix B - Qualification of Pipe

I. Listed Pipe Specifications. *[~~Numbers in parentheses indicate applicable editions.~~]*

API 5L - Steel pipe *[~~(1995).~~]*, **"API Specification for Line Pipe" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)).**

ASTM A 53/**A53M** - Steel pipe *[~~(1996).~~]*, **"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 (1)(D))**.

ASTM A 106 - Steel pipe *[~~(1995).~~]*, **"Standard Specification for Seamless Carbon Steel Pipe for High Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**.

ASTM A 333/A 333M - Steel pipe *[~~(1994).~~]*, **"Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**.

ASTM A 381 - Steel pipe *[~~(1993).~~]*, **"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 (1)(D))**.

ASTM A 671 - Steel pipe *[~~(1994).~~]*, **"Standard Specification for Electric-Fusion-Welded Pipe for Atmospheric and Lower Temperatures" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**.

ASTM A 672 - Steel pipe *[~~(1994)~~.]*, **"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 (1)(D)).**

ASTM A 691 - Steel pipe *[~~(1993)~~.]*, **"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 (1)(D)).**

ASTM D 2513 - Thermoplastic pipe and tubing *[~~(1996a)~~.]*, **"Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference in 49 CFR 192.7 and adopted in (1)(D)).**

[~~ASTM D 2517 - Thermosetting plastic pipe and tubing (1994)~~.]

II. Steel pipe of unknown or unlisted specification.

A. Bending properties. For pipe two inches (2") (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least ninety degrees (90°) around a cylindrical mandrel that has a diameter twelve (12) times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld. For pipe more than two inches (2") (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53 **(incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**, except that the number of tests must be at least equal to the minimum required in paragraph II.D. of this appendix to determine yield strength.

B. Weldability. A girth weld must be made in the pipe by a welder who is qualified under section (5) of 4 CSR 240-40.030. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than four inches (4") (102 millimeters) in diameter, at least one test weld must be made for each one hundred (100) lengths of pipe. On pipe four inches (4") (102 millimeters) or less in diameter, at least one test weld must be made for each four hundred (400) lengths of pipe. The weld must be tested in accordance with API Standard 1104 **(incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**. If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code **(incorporated by reference in 49 CFR 192.7 and adopted in (1)(D))**. The same number of chemical tests must be made as are required for testing a girth weld.

C. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. Tensile properties. If the tensile properties of the pipe are not known, the minimum yield strength may be taken as twenty-four thousand (24,000) psi (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L **(incorporated by**

reference in 49 CFR 192.7 and adopted in (1)(D)). All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests - All Sizes	
10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests.
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in paragraph (2)(C)3. of 4 CSR 240-40.030. (192.55[c])

Appendix C to 4 CSR 240-40.030
Appendix C - Qualification of Welders for Low Stress Level Pipe

I. Basic test. The test is made on pipe twelve inches (12") (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than one-eighth inch (1/8") (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. **A welder who successfully passes a butt-weld qualification test under this section shall be qualified to weld on all pipe diameters less than or equal to twelve (12) inches.**

Appendix E to 4 CSR 240-40.030
Appendix E. Table of Contents - Safety Standards - Transportation of Gas by Pipeline.

4 CSR 240-40.030(1) General

(A) *[~~Scope of rule~~]* **What Is the Scope of this Rule?** (192.1)

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

(E) Gathering Lines. (**192.8 and** 192.9)

(G) *[~~General.~~]* **What General Requirements Apply to Pipelines Regulated under this Rule?** (192.13)

4 CSR 240-40.030(5) Welding of Steel in Pipelines

(C) *[~~Qualification of~~]* Welding Procedures. (192.225)

4 CSR 240-40.030(9) Requirements for Corrosion Control

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

(N) Internal Corrosion Control – General **and Monitoring**. (192.475 **and 192. 477**)

(O) Internal Corrosion Control – *[~~Monitoring. (192.477)~~]* **Design and Construction of Transmission Line. (192.476)**

(W) Direct Assessment. (192.490)

4 CSR 240-40.030(12) Operations

(K) Public *[~~Education~~]* **Awareness.** (192.616)

4 CSR 240-40.030(13) Maintenance

(T) Pressure Limiting and Regulating Stations – *[~~Testing~~]* **Capacity** of Relief Devices. (192.743)

4 CSR 240-40.030(16) *[~~Waivers of Compliance.~~]* **Pipeline Integrity Management For Transmission Lines.**

4 CSR 240-40.030(17) Waivers of Compliance.

AUTHORITY: sections 386.250 and 386.310, RSMo Supp. 1999 and 393.140, RSMo 1994. 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 December 14, 2000, effective May 30, 2001. ***Amended: Filed October 15, 2007.***

PUBLIC ENTITY COST: This proposed amendment will not cost state agencies or political subdivisions more than $500 in the aggregate.

PRIVATE ENTITY COST: This proposed amendment will not cost private entities more than $500 in the aggregate.

NOTICE TO SUBMIT COMMENTS AND NOTICE OF PUBLIC HEARING: Anyone may file comments in support of or in opposition to this proposed rule with the Missouri Public Service Commission, Colleen M. Dale, Secretary of the Commission, P.O. Box 360, Jefferson City, MO 65102. To be considered, comments must be received at the Commission's offices on or before December 17, 2007, and should include a reference to Commission Case No. GX-2008-0032. Comments may also be submitted via a filing using the Commission's electronic filing and information system at <http://www.psc.mo.gov/efis.asp>. A public hearing regarding this proposed rule is scheduled for December 17, 2007 at 10:00 a.m. in the commission's offices in the Governor Office Building, 200 Madison Street, Jefferson City, Missouri. Interested persons may appear at this hearing to submit additional comments and/or testimony in support of or in opposition to this proposed rule, and may be asked to respond to commission questions. Any persons with special needs as addressed by the Americans with Disabilities Act should contact the Missouri Public Service Commission at least ten (10) days prior to the hearing at one (1) of the following numbers: Consumer Services Hotline 1-800-392-4211 (voice) or Relay Missouri at 711.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Proposed Amendments to Commission Rule 4 CSR 240-40, Gas Utilities and Gas Safety Standards	)))	**<u>Case No. GX-2008-0032</u>**

NOTICE OF FINDING OF NECESSITY

Issue Date: October 12, 2007

On August 3, 2007, the Commission opened this docket to consider proposed amendments to the following rules: 4 CSR 240-40.020, 4 CSR 240-40.030, and 4 CSR 240-40.080. The subject rules pertain to gas utilities and gas safety standards, and are necessary for the Commission to amend the rules to conform to amendments of 49 CFR and clarify the rules.

The Commission finds that the subject rules are necessary and seeks comments from interested persons as to whether the rules are appropriate and properly designed and written.

BY THE COMMISSION

Colleen M. Dale
Secretary

(S E A L)

Dated at Jefferson City, Missouri,
on this 12th day of October, 2007.

Dale, Chief Regulatory Law Judge

Small Business Regulator Fairness Board
Small Business Impact Statement

Date: August 2, 2007

Rule Number: 4 CSR 240-40.030

Name of Agency Preparing Statement: Missouri Public Service Commission

Name of Person Preparing Statement: Lera L. Shemwell

Phone Number: 751-7431 **Email: lera.shemwell@psc.mo.gov**

Name of Person Approving Statement: Colleen Dale

Please describe the methods your agency considered or used to reduce the impact on small businesses *(examples: consolidation, simplification, differing compliance, differing reporting requirements, less stringent deadlines, performance rather than design standards, exemption, or any other mitigating technique).*

This rule substantially codifies existing federal law, with which small businesses must already comply. There is no additional fiscal impact as a result of this rule.

Please explain how your agency has involved small businesses in the development of the proposed rule.
This rule substantially codifies existing federal law, with which small businesses must already comply. There is no additional fiscal impact as a result of this rule. No additional fiscal impact as a result of this rule.

Please list the probable monetary costs and benefits to your agency and any other agencies affected. Please include the estimated total amount your agency expects to collect from additionally imposed fees and how the moneys will be used.
No expected changes.

Please describe small businesses that will be required to comply with the proposed rule and how they may be adversely affected.
This rule substantially codifies existing federal law, with which small businesses must already comply. There is no additional fiscal impact as a result of this rule. No additional fiscal impact as a result of codification of existing federal law.

Please list direct and indirect costs (in dollars amounts) associated with compliance.

This rule substantially codifies existing federal law, with which small businesses must already comply. There is no additional fiscal impact as a result of this rule. No additional fiscal impact as a result of codification of existing federal law.

Please list types of business that will be directly affected by, bear the cost of, or directly benefit from the proposed rule.
Utility companies that transport natural gas.

Does the proposed rule include provisions that are more stringent than those mandated by comparable or related federal, state, or county standards?
Yes___ No_X__

If yes, please explain the reason for imposing a more stringent standard.

For further guidance in the completion of this statement, please see §536.300, RSMo.