Missouri Public Service Commission

POST OFFICE BOX 360
JEFFERSON CITY, MISSOURI 65102
573-751-3234
573-751-1847 (Fax Number)
http://www.psc.state.mo.us

December 15, 2000

Mr. Dale Hardy Roberts
Secretary/Chief Regulatory Law Judge
Missouri Public Service Commission
P. O. Box 360
Jefferson City, MO 65102

RE: Case No. GX-2001-91 – IN THE MATTER OF PROPOSED AMENDMENTS TO COMMISSION RULES 4 CSR 240-40.020 AND 40.030.

Dear Mr. Roberts:

Enclosed for filing in the above-captioned case are an original and eight (8) conformed copies of a **RULEMAKING PACKETS FOR PROPOSED AMENDMENTS TO RULE 4 CSR 240-40.020 AND 40.030.**

This filing has been mailed or hand-delivered this date to all counsel of record.

Thank you for your attention to this matter.

Sincerely yours,

Eric W. Anderson by TRS

Eric W. Anderson
Assistant General Counsel
(573) 751-7485
(573) 751-9285 (Fax)
e-mail: eandero@mail.state.mo.us

EWA/lb
Enclosure
cc: Counsel of Record

FILED

DEC 1 5 2000

Missouri Public
Service Commission

MEMORANDUM

TO: Dale Hardy Roberts, Secretary

DATE: December 14, 2000

RE: Authorization to File the Proposed Rule Amendments 4 CSR 240-40.020 and 4 CSR 240-40.030 With the Office of Secretary of State

CASE NO: GX-2001-91

The undersigned Commissioners hereby authorize the Secretary of the Missouri Public Service Commission to file the following Proposed Rule Amendments with the Office of Secretary of State, to wit:

4 CSR 240-40.020 – Incident, Annual and Safety-Related Condition Reporting Requirements
4 CSR 240-40.030 - Safety Standards-Transportation of Gas by Pipeline

Sheila Lumpe
Sheila Lumpe, Chair

M. Dianne Drainer, Vice Chair

-ABSENT-
Connie Murray, Commissioner

Robert Schemenauer
Robert Schemenauer, Commissioner

Kelvin L. Simmons
Kelvin L. Simmons, Commissioner

4

REBECCA MCDOWELL COOK
Secretary of State
Administrative Rules Division
RULE TRANSMITTAL

A "SEPARATE" rule transmittal sheet must be used for EACH individual rulemaking.

A. Rule Number **4 CSR 240-40.020**

Diskette File Name 4 CSR 240-40.020.doc

Name of Person to call with questions about this rule:

Content Eric Anderson Phone (573)751-7485 FAX (573)751-9285

Data Entry John Kottwitz Phone (573)751-7352 FAX (573)522-1926

Interagency Mailing Address Governor Office Building, 200 Madison Street, Suite 812

Statutory Provision for Rulemaking

Authority § 386.250, 386.310, 393.140 Provide Most Current RSMo Year 1999

Date Filed With the Joint Committee on Administrative Rules Not Applicable (Exempt pursuant To Section 536.037.3 RSMo Supp. 1999.)

B. CHECK, IF INCLUDED:

√ Cover Letter
√ Affidavit
√ Cost Statements
___ Public Entity Fiscal Note
___ Private Entity Fiscal Note

FORMS, List by Mo-Form Number, # of Pages

OTHER

C. RULEMAKING ACTION TO BE TAKEN

___ Emergency Rulemaking, Must Specify Effective Date
√ Proposed Rulemaking (New Rule or Amendment or Rescission of Existing Rule)
___ Order of Rulemaking (MUST complete page 2 of this transmittal)
___ Withdrawal (Rule, Amendment, Rescission or Emergency)
___ Rule Action Notice
___ In Addition

D. SPECIFIC INSTRUCTIONS: In this space indicate any special instructions (e.g., specify publication date preference, identify material incorporated by references, etc:)

Small Business Analysis is included.

E. ORDER OF RULEMAKING: Rule Number N/A

1a. Effective Date for the Order
Statutory 30 days _______ or later specific date ________________

1b. Does the Order of Rulemaking contain changes to the rule text?
YES _______ NO _______

1c. If the answer is YES, please complete section F. If the answer is NO, Stop here.

F. Please provide a complete list of the changes in the rule text for the order or rulemaking, indicating the specific section, subsection, subparagraph, part, etc., where each change is found.

(**Start text here.** If text continues to a third page, insert a continuous section break and, in section 3, delete the footer language that appears at the bottom of this page.)

NOTE: ALL changes MUST be specified here in order for those changes to be made in the rule as published in the *Missouri Register* and the *Code of State Regulations*.

Add additional sheet(s), if more space is needed.

COPY

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DEC 14 2000

SECRETARY OF STATE
ADMINISTRATIVE RULES

Missouri Public Service Commission

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573-751-1847 (Fax Number)
http://www.psc.state.mo.us

December 14, 2000

Honorable Rebecca McDowell Cook
Secretary of State
600 West Main Street
Jefferson City, MO 65101

ATTENTION: Administrative Rules Division

I do hereby certify that the attached are accurate and complete copies of the Proposed Rule Amendment lawfully submitted by the Missouri Public Service Commission for filing this 14th day of December. As this proposed amended rule substantially codifies existing federal law a takings analysis is not necessary under section 536.017 RSMo Supp. 1999 and a small business analysis is not required by Executive Order 96-18. Section 536.205 RSMo 1994 does not require a fiscal note as this agency anticipates that the fiscal impact on private entities will be less than five hundred dollars in aggregate. A Public Entity Cost Affidavit is included in this packet.

Proposed Amendment to Rule: 4 CSR 240-40.020 - Incident, Annual and Safety-Related Condition Reporting Requirements.
Statutory Authority: § 386.250 and 386.310, RSMo 1999 and 393.140, RSMo 1994.
Missouri Public Service Commission Case No.: GX-2001-91

If there are any questions please contact:

Eric William Anderson, Assistant General Counsel
Missouri Public Service Commission
P. O. Box 360
Jefferson City, MO 65102
(573) 751-7485 (Telephone)
(573) 751-9285 (Fax)
canderso@mail.state.mo.us

BY THE COMMISSION

Dale Hardy Roberts
Secretary

Enclosures

Commissioners
SHEILA LUMPE
Chair
M. DIANNE DRAINER
Vice Chair
CONNIE MURRAY
ROBERT G. SCHEMENAUER
KELVIN L. SIMMONS

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Executive Director
GORDON L. PERSINGER
Director, Research and Public Affairs
WESS A. HENDERSON
Director, Utility Operations
ROBERT SCHALLENBERG
Director, Utility Services
DONNA M. KOLILIS
Director, Administration
DALE HARDY ROBERTS
Secretary/Chief Regulatory Law Judge
DANA K. JOYCE
General Counsel

October 27, 2000

Joseph L. Driskill, Director
Department of Economic Development
301 West High Street
Jefferson City, MO 65101

RE: **Proposed Rulemaking Affidavit for Proposed Amendment to 4 CSR 240-40.020**

Dear Mr. Driskill:

The Public Service Commission is proposing to amend rule **4 CSR 240-40.020 Incident, Annual and Safety-Related Condition Reporting Requirements**. This proposed amendment to the rule is made to incorporate updates to corresponding federal amendments. As this proposed amended rule substantially codifies existing federal law a takings analysis is not necessary under section 536.017 RSMo Supp. 1999 and a small business analysis is not required by Executive Order 96-18. A fiscal note is not required by section 536.200 RSMo 1994 as this agency anticipates that any fiscal impact on this agency, any other agency of state government or any political subdivision thereof will be less than five hundred dollars in the aggregate. Additionally, section 536.205 RSMo 1994 does not require a fiscal note as this agency anticipates that the fiscal impact on private entities will be less than five hundred dollars in aggregate. While section 536.200 does not require the filing of a fiscal note in this instance it does require a signed affidavit by the director of the department. After reviewing the attached Proposed Amendment, please sign the corresponding Affidavit before a notary public and return it to me.

Sincerely,

Eric Anderson

Eric William Anderson
Assistant General Counsel

Enclosures

AFFIDAVIT

STATE OF MISSOURI }
COUNTY OF COLE }

I, Joseph L. Driskill, 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* to 4 CSR 240-40.020 is less than five hundred dollars in the aggregate to this agency, any other agency of state government or any political subdivision thereof.

Joseph L. Driskill
Joseph L. Driskill
Director
Department of Economic Development

Subscribed and sworn to before me this 31 day of October, 20 00. I am commissioned as a notary public within the County of Callaway, State of Missouri, and my commission expires on July 5, 2004.

Shelia A. Helzer
NOTARY PUBLIC

SHELIA A HELZER
NOTARY PUBLIC STATE OF MISSOURI
CALLAWAY COUNTY
MY COMMISSION EXP. JULY 5,2004

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DEC 1 4 2000
SECRETARY OF STATE
ADMINISTRATIVE RULES
COPY

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

PROPOSED AMENDMENT

4 CSR 240-40.020 Incident, Annual and Safety-Related Condition Reporting Requirements. The Commission is amending sections (1) and (12).

PURPOSE: This proposed amendment modifies the scope of this rule to be consistent with 4 CSR 240-40.030 for gathering lines and amends the rule to conform to an amendment of 49 CFR part 191.

(1) Scope. (191.1)

(B) This rule does not apply to *[onshore]* gathering of gas **on private property** outside of–
1. An area within the limits of any incorporated or unincorporated city, town or village; or
2. Any designated residential or commercial area such as a subdivision, business or shopping center or community development.

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

(B) A report is not required for any safety-related condition that—
1. Exists on a master meter system or a customer-owned service line;
2. Is an incident or results in an incident before the deadline for filing the safety-related condition report;
3. Exists on a pipeline (other than an LNG facility) that is more than two hundred twenty (220) yards **{200 meters}** from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street or highway; or
4. Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (12)(A)1. other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.

AUTHORITY: sections 386.250 and 386.310, RSMo Supp. 1999 and 393.140, RSMo 1994. Original rule filed Feb. 5, 1970, effective Feb. 26, 1970. Amended: Filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed Feb. 8, 1985, effective Aug. 11, 1985. Rescinded and readopted: Filed May 17, 1989, effective Dec. 15, 1989. Amended: Filed Oct. 7, 1994, effective May 28, 1995. Amended: Filed April 9, 1998, effective Nov. 30, 1998. ***Amended: Filed December x, 2000.***

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: Anyone may file comments in support of or in opposition to this Proposed Amendment with the Missouri Public Service Commission, Dale Hardy Roberts, Secretary, P.O. Box 360, Jefferson City, MO 65102. To be considered, comments must be received within thirty days after publication of this notice in the ***Missouri Register****. Comments should refer to Case No. GX-2001-91 and be filed with an original and eight (8) copies. No public hearing is scheduled.*

REBECCA MCDOWELL COOK
Secretary of State
Administrative Rules Division
RULE TRANSMITTAL

A "SEPARATE" rule transmittal sheet must be used for EACH individual rulemaking.

A. Rule Number **4 CSR 240-40.030**

Diskette File Name 4 CSR 240-40.030.doc

Name of Person to call with questions about this rule:

Content Eric Anderson Phone (573)751-7485 FAX (573)751-9285

Data Entry John Kottwitz Phone (573)751-7352 FAX (573)522-1926

Interagency Mailing Address Governor Office Building, 200 Madison Street, Suite 812

Statutory Provision for Rulemaking
Authority § 386.250, 386.310, 393.140 Provide Most Current RSMo Year 1999

Date Filed With the Joint Committee on Administrative Rules Not Applicable (Exempt pursuant To Section 536.037.3 RSMo Supp. 1999.)

B. CHECK, IF INCLUDED:

√ Cover Letter
√ Affidavit
√ Cost Statements
___ Public Entity Fiscal Note
___ Private Entity Fiscal Note

FORMS, List by Mo-Form Number, # of Pages

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E. ORDER OF RULEMAKING: Rule Number N/A

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Statutory 30 days ______ or later specific date ______

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YES ______ NO ______

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NOTE: ALL changes MUST be specified here in order for those changes to be made in the rule as published in the *Missouri Register* and the *Code of State Regulations.*

Add additional sheet(s), if more space is needed.

BRIAN D. KINKADE
Executive Director
GORDON L. PERSINGER
Director, Research and Public Affairs
WESS A. HENDERSON
Director, Utility Operations
ROBERT SCHALLENBERG
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December 14, 2000

Honorable Rebecca McDowell Cook
Secretary of State
600 West Main Street
Jefferson City, MO 65101

ATTENTION: Administrative Rules Division

I do hereby certify that the attached are accurate and complete copies of the Proposed Rule Amendment lawfully submitted by the Missouri Public Service Commission for filing this 14th day of December. As this proposed amended rule substantially codifies existing federal law a takings analysis is not necessary under section 536.017 RSMo Supp. 1999 and a small business analysis is not required by Executive Order 96-18. Section 536.205 RSMo 1994 does not require a fiscal note as this agency anticipates that the fiscal impact on private entities will be less than five hundred dollars in aggregate. A Public Entity Cost Affidavit is included in this packet.

Proposed Amendment to Rule: 4 CSR 240-40.030 - Safety Standards-Transportation of Gas by Pipeline.
Statutory Authority: § 386.250 and 386.310, RSMo 1999 and 393.140, RSMo 1994.
Missouri Public Service Commission Case No.: GX-2001-91

If there are any questions please contact:

Eric William Anderson, Assistant General Counsel
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canderso@mail.state.mo.us

BY THE COMMISSION

Dale Hardy Roberts
Secretary

Enclosures

Missouri Public Service Commission

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http://www.psc.state.mo.us

October 27, 2000

Joseph L. Driskill, Director
Department of Economic Development
301 West High Street
Jefferson City, MO 65101

RE: **Proposed Rulemaking Affidavit for Proposed Amendment to 4 CSR 240-40.030**

Dear Mr. Driskill:

The Public Service Commission is proposing to amend rule **4 CSR 240-40.030 Safety Standards-Transportation of Gas by Pipeline**. This proposed amendment to the rule is made to incorporate updates to corresponding federal amendments. As this proposed amended rule substantially codifies existing federal law a takings analysis is not necessary under section 536.017 RSMo Supp. 1999 and a small business analysis is not required by Executive Order 96-18. A fiscal note is not required by section 536.200 RSMo 1994 as this agency anticipates that any fiscal impact on this agency, any other agency of state government or any political subdivision thereof will be less than five hundred dollars in the aggregate. Additionally, section 536.205 RSMo 1994 does not require a fiscal note as this agency anticipates that the fiscal impact on private entities will be less than five hundred dollars in aggregate. While section 536.200 does not require the filing of a fiscal note in this instance it does require a signed affidavit by the director of the department. After reviewing the attached Proposed Amendment, please sign the corresponding Affidavit before a notary public and return it to me.

Sincerely,

Eric Anderson

Eric William Anderson
Assistant General Counsel

Enclosures

AFFIDAVIT

STATE OF MISSOURI }
COUNTY OF COLE }

I, Joseph L. Driskill, 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* to 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.

Joseph L. Driskill

Joseph L. Driskill
Director
Department of Economic Development

Subscribed and sworn to before me this 31 day of October, 2000. I am commissioned as a notary public within the County of Callaway, State of Missouri, and my commission expires on July 5, 2004.

Shelia A. Helzer

NOTARY PUBLIC

SHELIA A HELZER
NOTARY PUBLIC STATE OF MISSOURI
CALLAWAY COUNTY
MY COMMISSION EXP. JULY 5,2004

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PROPOSED AMENDMENT

4 CSR 240–40.030 Safety Standards–Transportation of Gas by Pipeline. The Commission is amending 4 CSR 240-40.030 sections (1), (2), (3), (4), (5), (6), (7), (8), (9), (10), (11), (12), (13), (14), Appendix A, Appendix B and Appendix 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.

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

1. Abandoned means permanently removed from service;

[1.] **2.** Administrator means the Administrator of the Research and Special Programs Administration of the United States Department of Transportation or any person to whom authority in the matter concerned has been delegated by the Secretary of the United States Department of Transportation;

[2.] **3.** Building means any structure *[which]* **that** is regularly or periodically occupied by people;

[3.] **4.** Commission means the Missouri Public Service Commission, and designated commission personnel means the Pipeline Safety Program Manager at the address contained in 4 CSR 240-40.020(5) for required correspondence;

[4.] **5.** Distribution line means a pipeline other than a gathering or transmission line*[;*

*5. Feeder]***, and feeder** line means a distribution line that has a maximum allowable operating pressure **(MAOP)** greater than *[one hundred pounds per square inch gauge (100 psig), but]* **100 psi {689 kPa} gauge that** produces hoop stresses less than twenty percent (20%) **of** specified minimum yield strength (SMYS);

6. 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 *[insure]* **ensure** that all hazardous leaks in the area are corrected;

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

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

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

10. 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. 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. Listed specification means a specification listed in subsection I. of Appendix B;

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

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

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

18. Operator means a person who engages in the transportation of gas, and 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. Petroleum gas means propane, propylene, butane (normal butane or *[isobultanes]* **isobutanes**), and butylene (including isomers), or mixtures composed predominately of these gases, having a vapor pressure not exceeding *[1434 kPa (208 psig) at 38°C (100°F)]* **208 psi {1434 kPa} gauge at 100°F {38°C}**;

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

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

24. 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;

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

27. 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 a hoop stress of twenty percent (20%) or more of SMYS; or

C. Transports gas within a storage field;

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

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

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

31. 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.

(C) Class Locations. (192.5)

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

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

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

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

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

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

C. A Class 3 location is–

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

(II) An area where the pipeline lies within one hundred (100) yards **{91 meters}** of either a building or a small, well-defined outside area (*[for instance,]* **such as** a playground, recreation area, outdoor theater or other place of public assembly) that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period (The days and weeks need not be consecutive); and

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

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

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

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

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

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

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

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

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

C. Buried gas piping should be–

(I) Periodically inspected for leaks;

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

(III) Repaired if any unsafe condition is discovered;

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

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

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

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

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

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

(2) Materials.

(C) Steel Pipe. (192.55)

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

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

B. It meets the requirements of–

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

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

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

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

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

B. It meets the requirements of–

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

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

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

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

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

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

5. New steel pipe that has been cold expanded must comply with the mandatory provisions of API Specification 5L.

(3) Pipe Design.

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

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

P = (2 St/D) x F x E x T

where–

P = Design pressure in pounds per square inch **{kPa}** gauge;

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

D = Nominal outside diameter of the pipe in inches **{millimeters}**;

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

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

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

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

2. If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to seventy-five percent (75%) of the pressure determined under paragraph (3)(C)1. if the temperature of the pipe exceeds *[nine hundred degrees Fahrenheit (900°F) (four hundred eighty-two degrees Celsius (482°C))]* **900°F {482°C}** at any time or is held above *[six hundred degrees Fahrenheit (600°F) (three hundred and sixteen degrees Celsius (316°C))]* **600°F {316°C}** for more than one (1) hour.

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

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

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

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

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

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

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

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

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

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

(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) (192.105) is determined in accordance with the following table:

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

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

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

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

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

(I) Design of Plastic Pipe. (192.121) Subject to the limitations of subsection (3)(J) (192.123), 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*[, kPa (psig)]*;

S = For thermoplastic pipe, the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to *[23°C (73°F), 38°C (100°F), 49°C (120°F) or 60°C (140°F) kPa (psi)]* **73°F {23°C}, 100°F {38°C}, 120°F {49°C} or 140°F {60°C}, psi {kPa}**;

t = Specified wall thickness, *[mm (in)]* **in {mm}**;

D = Specified outside diameter, *[mm (in)]* **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 *[six hundred eighty-nine (689) kPa (100 psig)]* **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 *[-29°C (-20°F)]* **-20°F {-29°C}**, or *[-40°C (-40°F)]* **-40°F {-40°C}** if all pipe and pipeline components whose operating temperature will be below *[-29°C (-20°F)]* **-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 used in the design formula under subsection (3)(I) (192.121) is determined. However, if the pipe was manufactured before May 18, 1978, and its long-term hydrostatic strength was determined at *[23°C (73°F)]* **73°F {23°C}**, it may be used at temperatures up to *[38°C (100°F)]* **100°F {38°C}**.

3. The wall thickness for thermoplastic pipe may not be less than *[1.57 millimeters (0.062 in)]* **0.062 inches {1.57 millimeters}**.

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

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

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

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

3. Copper pipe used in mains and service lines may not be used at pressures in excess of *[one hundred (100) psig]* **100 psi {689 kPa} gauge.**

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

(D) Valves. *[(145)]* **(192.145)**

1. Except for cast iron and plastic valves, each valve must meet the minimum requirements, or the equivalent, of API 6D. 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 *[one thousand (1000) psig]* **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.

(G) Tapping. (192.151)

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

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

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

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

B. A one and one-fourth inch (1 ¼") **{32 millimeters}** tap may be made in a four-inch (4") **{102 millimeters}** cast iron or ductile iron pipe, without reinforcement.

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

(H) Components Fabricated by Welding. (192.153)

1. Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of section VIII*[,]*-Division I, of the *ASME Boiler and Pressure Vessel Code.*

2. Each prefabricated unit that uses plate and longitudinal seams must be designated, constructed and tested in accordance with section I, section VIII-Division 1, or section VIII-Division 2 of the *ASME Boiler and Pressure Vessel Code*, except for the following:

A. Regularly manufactured butt-welding fittings;

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

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

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

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

4. Except for flat closures designed in accordance with section VIII of the *ASME Boiler and Pressure Code*, flat closures and fish tails may not be used on pipe that either operates at *[one hundred (100) psig]* **100 psi {689 kPa} gauge** or more, or is more than three inches (3") **{76 millimeters}** nominal diameter.

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

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

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

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

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

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

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

5. Electrical facilities. Electrical equipment and wiring installed in compressor stations must conform to the *National Electrical Code*, ANSI/NFPA 70, so far as that code is applicable.

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

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

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

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

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

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

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

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

(I) Outside the gas area of the station;

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

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

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

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

A. In the case of an unattended compressor station–

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

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

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

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

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

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

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

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

C = (3D x P x F)/1000 **{C = (D x P x F)/2298}**

where

C = Minimum clearance between pipe containers or bottles in inches **{millimeters}**;

D = Outside diameter of pipe containers or bottles in inches **{millimeters}**;

P = Maximum allowable operating pressure, *[psig]* **psi {kPa} gauge**; and

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

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

1. Each bottle-type holder must be–

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

Maximum Allowable Operating Pressure	Minimum Clearance *[(feet)]* **feet {meters}**
Less than 1000 psi*[g]* **{7 MPa} gauge**	25 **{7.6}**
1000 psi*[g]* **{7 MPa} gauge** or more	100 **{31}**

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

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

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

A. A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A 372/A 372M;

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

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

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

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

(U) Transmission Line Valves. (192.179)

1. Each transmission line must have sectionalizing block valves spaced as follows, unless in a particular case the administrator finds that alternative spacing would provide an equivalent level of safety:

A. Each point on the pipeline in a Class 4 location must be within two and one-half (2 ½) miles **{4 kilometers}** of a valve;

B. Each point on the pipeline in a Class 3 location must be within four (4) miles **{6.4 kilometers}** of a valve;

C. Each point on the pipeline in a Class 2 location must be within seven and one-half (7 ½) miles **{12 kilometers}** of a valve; and

D. Each point on the pipeline in a Class 1 location must be within ten (10) miles **{16 kilometers}** of a valve.

2. Each sectionalizing block valve on a transmission line must comply with the following:

A. The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage; and

B. The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.

3. Each section of a transmission line between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

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

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

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

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

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

1. When the internal volume exceeds two hundred (200) cubic feet **{5.7 cubic meters}**–

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

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

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

2. When the internal volume is more than seventy-five (75) cubic feet **{2.1 cubic meters}** but less than two hundred (200) cubic feet **{5.7 cubic meters}**–

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) Welding of Steel in Pipelines.

(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 welded with that process.

3. A welder qualified under paragraph (5)(D)1. (192.227[a])–

A. May not weld on pipe to be operated at a pressure that produces a hoop stress of twenty percent (20%) or more of SMYS unless within the preceding six (6) calendar months the welder has had one (1) weld tested and found acceptable under section 3 or 6 of API Standard 1104, except that a welder qualified under an earlier edition previously listed in Appendix A to 49 CFR Part 192 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. (192.227[b]) 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. (192.227[b]); or

B. Within the preceding seven and one-half (7 1/2) 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 to *[insure]* **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) (192.243), 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 of API Standard 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix 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. (192.273[b]) 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]) of ASTM D2513;

(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; 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;

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, 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. (192.273[b]) 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);

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 *[five millimeters (5 mm) (0.20")]* **0.20 inches {5.0 mm}** per minute, plus or minus twenty-five percent (25%);

D. Pipe specimens less than *[one hundred and two millimeters (102 mm) (4")]* **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 *[one hundred and two millimeters (102 mm) (4")]* **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 *[fifty-five degrees Celsius (55°C) (100°F)]* **100°F {38°C}** or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five (5) test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress;

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

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

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

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

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

(E) Repair of Steel Pipe. (192.309)

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

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

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

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

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

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

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

(I) More than one-quarter inch (1/4") **{6.4 millimeters}** in pipe twelve and three-quarters inches (12 ¾") **{324 millimeters}** or less in outer diameter; or

(II) More than two percent (2%) of the nominal pipe diameter in pipe over twelve and three-quarters inches (12¾") **{324 millimeters}** in outer diameter.*[ ]*

For the purpose of this subsection, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

3. Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of forty percent (40%) or more of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either–

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

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

4. A gouge, groove, arc burn or dent may not be repaired by insert patching or by pounding out.

5. Each gouge, groove, arc burn or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

(G) Bends and Elbows. (192.313)

1. Each field bend in steel pipe, other than a wrinkle bend made in accordance with subsection (7)(H) (192.315), must comply with the following:

A. A bend must not impair the serviceability of the pipe;

B. Each bend must have a smooth contour and be free from buckling, cracks or any other mechanical damage; and

C. On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless–

(I) The bend is made with an internal bending mandrel; or

(II) The pipe is twelve inches (12") **{305 millimeters}** or less in outside diameter or has a diameter-to-wall thickness ratio less than seventy (70).

2. Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.

3. Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is two inches (2") **{51 millimeters}** or more in diameter unless the arc length, as measured along the crotch, is at least one inch (1") **{25 millimeters}**.

(H) Wrinkle Bends in Steel Pipe. (192.315)

1. A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of thirty percent (30%), or more, of SMYS.

2. Each wrinkle bend on steel pipe must comply with the following:

A. The bend must not have any sharp kinks;

B. When measured along the crotch of the bend, the wrinkles must be a distance of at least one (1) pipe diameter;

C. On pipe sixteen inches (16") **{406 millimeters}** or larger in diameter, the bend may not have a deflection of more than one and one-half degrees (1½°) for each wrinkle; and

D. On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

(K) Installation of Plastic Pipe. (192.321)

1. Plastic pipe must be installed below ground level unless otherwise permitted by paragraph (7)(K)7.

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.

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.

(M) Underground Clearance. (192.325)

1. Each transmission line must be installed with at least twelve inches (12") **{305 millimeters}** of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.

2. Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

3. In addition to meeting the requirements of paragraph (7)(M)1. or 2., each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

4. Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in paragraph (4)(S)2. (192.175[b])

(N) Cover. (192.327)

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

Location	Normal Soil	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 **{762}**	24 **{762}**

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.*[of this section]*, 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 natural bottom.

(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. 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.

(F) Customer Meter Installations–Operating Pressure. (192.359)

1. A meter may not be used at a pressure that is more than sixty-seven percent (67%) of the manufacturer's shell test pressure.

2. Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of ten (10) psi*[g]* **{69 kPa} gauge**.

3. A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than fifty percent (50%) percent of the pressure used to test the meter after rebuilding or repairing.

(G) Service Lines–Installation. (192.361)

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

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

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

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

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

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

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

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

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

A. It must be encased in a gastight conduit;

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

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

(L) Service Lines–Steel. (192.371) Each steel service line to be operated at less than one hundred (100) psi*[g]* **{689 kPa} gauge** must be constructed of pipe designed for a minimum of one hundred (100) psi*[g]* **{689 kPa} gauge**.

(O) Service Lines–Excess Flow Valve Performance Standards. (192.371)

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

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

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

C. At ten (10) psi*[g]* **{69 kPa} gauge**:

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

(II) Upon closure, reduce gas flow–

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

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

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

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

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

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

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

(P) Excess Flow Valve Customer Notification. (192.383)

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

A. *Costs associated with installation* means the costs directly connected with installing an excess flow valve, for example, costs of parts, labor, inventory and procurement. It does not include maintenance and replacement costs until such costs are incurred.

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

C. *Service line customer* means the person who pays the gas bill, or where service has not yet been established, the person requesting service.

2. *Which customers must receive notification.* Notification is required on each newly installed service line or replaced service line that operates continuously throughout the year at a pressure not less than ten (10) psi {69 kPa} gauge and that serves a single residence. On these lines an operator of a natural gas distribution system must notify the service line customer once in writing.

3. *What to put in the written notice.*

A. An explanation for the customer that an excess flow valve (EFV) meeting the performance standards prescribed under subsection (8)(O) is available for the operator to install if the customer bears the costs associated with installation;

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

C. A description of installation, maintenance, and replacement costs. The notice must explain that if the customer requests the operator to install an EFV, the customer bears all costs associated with installation, and what those costs are. The notice must alert the customer that costs for maintaining and replacing an EFV may later be incurred, and what those costs will be, to the extent known.

4. *When notification and installation must be made.*

A. After February 3, 1999, an operator must notify each service line customer set forth in paragraph (8)(P)2.:

(I) On new service lines when the customer applies for service; and

(II) On replaced service lines when the operator determines the service line will be replaced.

B. If a service line customer requests installation, an operator must install the EFV at a mutually agreeable date.

5. *What records are required.*

A. An operator must make the following records available for inspection by designated commission personnel:

(I) A copy of the notice currently in use; and

(II) Evidence that notice has been sent to the service line customers set forth in paragraph (8)(P)2., within the previous three years.

B. (Reserved)

6. *When notification is not required.* The notification requirements do not apply if the operator can demonstrate–

A. That the operator will voluntarily install an excess flow valve or that the state or local jurisdiction requires installation;

B. That excess flow valves meeting the performance standards in subsection (8)(O) are not available to the operator;

C. That the operator has prior experience with contaminants in the gas stream that could interfere with the operation of an excess flow valve, cause loss of service to a residence, or interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

D. That an emergency or short time notice replacement situation made it impractical for the operator to notify a service line customer before replacing a service line. Examples of these situations would be where an operator has to replace a service line quickly because of–

(I) Third party excavation damage;

(II) Class 1 leaks as defined in the paragraph (14)(C)1.; or

(III) A short notice service line relocation request.

(9) Requirements for Corrosion Control.

(F) External Corrosion Control–Inspection of Buried Pipeline When Exposed. (192.459) Whenever an operator has knowledge that any portion of a buried metallic pipeline is exposed, an inspection of the exposed portion must be conducted. If the pipe is coated, the condition of the coating must be determined. If the pipe is bare or if the coating is deteriorated, the surface of the pipe must be examined for evidence of external corrosion. *[If the operator finds that there is active corrosion, that the surface of the pipe is pitted due to corrosion, or that corrosion has caused a leak, it shall investigate by records review and by excavation to determine the extent of the corrosion requiring remedial action.]* If external corrosion *[is found,]* **requiring** remedial action *[must be taken to the extent required by]* **under** subsections (9)(R) **through (9)(U)** (192.483 **through 192.489)** *[and the applicable paragraphs of subsections of (9)(S), (T) or (U). (192.485, 192.487, or 192.489)]* **is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.**

(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') **{30 meters}** 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 electronically 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 (six) times each calendar year but with intervals not exceeding two and one-half (2 1/2) months to *[insure]* **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.C3. Corrective measures must be completed within six (6) months unless otherwise approved by designated commission personnel.

5. After the initial evaluation required by paragraph (9)(D)2. (192.455[c]) and paragraph (9)(E)2. (192.457[b]), each operator, at intervals not exceeding three (3) years, shall reevaluate its unprotected pipelines and cathodically protect them in accordance with this section 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 determine the areas of active corrosion by electrical survey at intervals not exceeding three (3) years. 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 at intervals not exceeding three (3) years. When the operator conducts electrical surveys, the operator must demonstrate that the surveys effectively identify areas of active corrosion.

(N) Internal Corrosion Control–General. (192.475)

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) *[standard]* cubic feet **{5.8 milligrams/m^3} at standard conditions** (four (4) parts per million) may not be stored in pipe-type or bottle-type holders.

(S) Remedial Measures–Transmission Lines. (192.485)

1. General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, *[if the area of general corrosion is small, the]* corroded pipe may be repaired **by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe**. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

2. Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must

be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits.

3. Under paragraphs (9)(S)1. and (9)(S)2., the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

(T) Remedial Measures–Distribution Lines Other Than Cast Iron or Ductile Iron Lines. (192.487)

1. General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, or a remaining wall thickness less than thirty percent (30%) of the nominal wall thickness, must be replaced. However, *[if the area of general corrosion is small, the]* corroded pipe may be repaired **by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe**. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

2. Localized corrosion pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

(V) Corrosion Control Records. (192.491)

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

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

3. Each operator shall maintain a record of each test, survey, inspection *[or]* **and** remedial action required by this section in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least five (5) years, except that records related to paragraphs (9)(I)1., (9)(I)4., (9)(I)5., and (9)(N)2. must be retained for as long as the pipeline remains in service.

(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}** feet 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.

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.

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

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

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

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

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

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

(E) Test Requirements for Pipelines to Operate Below One Hundred (100) psi*[g]* **{689 kPa} gauge.** (192.509) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below one hundred (100) psi*[g]* **{689 kPa} gauge** must be tested in accordance with the following:

1. The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested;

2. Each main that is to be operated at less than one (1) psi*[g]* **{6.9 kPa} gauge** must be tested to at least ten (10) psi*[g]* **{69 kPa} gauge**, each main to be operated at or above one (1) psi*[g]* **{6.9 kPa} gauge** through ninety (90) psi*[g]* **{621 kPa} gauge** must be tested to at least ninety (90) psi*[g]* **{621 kPa} gauge**, and each main that is to be operated between ninety (90) psi*[g]* **{621 kPa} gauge** and one hundred (100) psi*[g]* **{689 kPa} gauge** must be tested to at least one hundred (100) psi*[g]* **{689 kPa} gauge**.

(F) Test Requirements for Service Lines. (192.511)

1. Each segment of a service line (other than plastic) must be leak tested in accordance with this subsection before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

2. Each segment of a service line (other than plastic) intended to be operated at a pressure of at least one (1) psi*[g]* **{6.9 kPa} gauge** but not more than forty (40) psi*[g]* **{276 kPa} gauge** must be given a leak test at a pressure of not less than fifty (50) psi*[g]* **{345 kPa} gauge**.

3. Each segment of a service line (other than plastic) intended to be operated at pressures of more than forty (40) psi*[g]* **{276 kPa} gauge** through ninety (90) psi*[g]* **{621 kPa} gauge** must be tested to at

least ninety (90) psi*[g]* **{621 kPa} gauge**; if the service line is to be operated between ninety (90) psi*[g]* **{621 kPa} gauge** and one hundred (100) psi*[g]* **{689 kPa} gauge**, it must be tested to at least one hundred (100) psi*[g]* **{689 kPa} gauge**; and if the service line may be operated at 100 psi*[g]* **{689 kPa} gauge** or more, it must, at a minimum, be tested using the appropriate factor in subparagraph (12)(M)1.B. of this rule, except that each segment of the steel service line stressed to twenty percent (20%) or more of SMYS must be tested in accordance with subsection (10)(D)*[of this rule. (192.507)]*.

(G) Test Requirements for Plastic Pipelines. (192.513)

1. Each segment of a plastic pipeline must be tested in accordance with this subsection.

2. The test procedure must ensure discovery of all potentially hazardous leaks in the segment being tested.

3. The test pressure must be at least one hundred fifty percent (150%) of the maximum allowable operating pressure or fifty (50) psi*[g]* **{345 kPa} gauge**, whichever is greater. However, the maximum test pressure may not be more than three (3) times the pressure determined under subsection (3)(I), at a temperature not less than the pipe temperature during the test.

4. During the test, the temperature of thermoplastic material may not be more than *[38°C (100°F)]* **100°F (38°C)**, or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

(H) Environmental Protection and Safety Requirements. (192.515)

1. In conducting tests under this section, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed fifty percent (50%) of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

2. The operator shall *[insure]* **ensure** that the test medium is disposed of in a manner that will minimize damage to the environment.

(11) Uprating.

(D) Uprating–Steel Pipelines to a Pressure That Will Produce a Hoop Stress Less Than Thirty Percent (30%) of SMYS–Plastic, Cast Iron and Ductile Iron Pipelines. (192.557)

1. Unless the requirements of this subsection have been met, no person may subject–

A. A segment of steel pipeline to an operating pressure that will produce a hoop stress less than thirty percent (30%) of SMYS and that is above the previously established maximum allowable operating pressure; or

B. A plastic, cast iron or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.

2. Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall–

A. Review the design, operating and maintenance history of the segment of pipeline;

B. Conduct a leak detection instrument survey (if it has been more than one (1) year since the last survey conducted with a leak detection instrument) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;

C. Make any repairs, replacements or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;

D. Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell and spigot joints to prevent failure of the pipe joint, if the offset, bend or dead end is exposed in an excavation;

E. Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

F. If the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

3. After complying with paragraph(11)(D)2., the increase in maximum allowable operating pressure must be made in accordance with paragraph (11)(B)5. The pressure must be increased in increments that are equal to ten (10) psi*[g]* **{69 kPa} gauge** or twenty-five percent (25%) of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of subparagraph (11)(D)2.F. apply, there must be at least two (2) approximately equal incremental increases.

4. If records for cast iron or ductile iron pipeline facilities are not complete enough to determine stresses produced by internal pressure, trench loading, rolling loads, beam stresses and other bending loads, in evaluating the level of safety of the pipeline when operating at the proposed increased pressure, the following procedures must be followed:

A. In estimating the stresses, if the original laying conditions cannot be ascertained, the operator shall assume that cast iron pipe was supported on blocks with tamped backfill and that ductile iron pipe was laid without blocks with tamped backfill;

B. Unless the actual maximum cover depth is known, the operator shall measure the actual cover in at least three (3) places where the cover is most likely to be greatest and shall use the greatest cover measured;

C. Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three (3) separate pipe lengths. The coupons must be cut from pipe lengths in areas where the cover depth is most likely to be the greatest. The average of all measurements taken must be increased by the allowance indicated in the following table:

	Allowance (inches) **{millimeters}**		
	Cast iron pipe		
Pipe size (inches) **{millimeters}**	Pit cast pipe	Centrifugally cast pipe	Ductile iron pipe
3 to 8 **{76 to 203}**	0.075 **{1.91}**	0.065 **{1.65}**	0.065**{1.65}**
10 to 12 **{254 to 305}**	0.08 **{2.03}**	0.07 **{1.78}**	0.07 **{1.78}**
14 to 24 **{356 to 610}**	0.08 **{2.03}**	0.08 **{2.03}**	0.075 **{1.91}**
30 to 42 **{762 to 1067}**	0.09 **{2.29}**	0.09 **{2.29}**	0.075 **{1.91}**
48 **{1219}**	0.09 **{2.29}**	0.09 **{2.29}**	0.08 **{2.03}**
54 to 60 **{1372 to 1524}**	0.09 **{2.29}**	---	---

D. For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with a bursting tensile strength of eleven thousand (11,000) psi **{76 MPa}** and a modulus of rupture of thirty-one thousand (31,000) psi **{214 MPa}**.

(12) Operations.

(D) *[Personnel]* Qualification **of Pipeline Personnel (Subpart N)**.

[1. No operator may permit an individual (operators themselves, employees of operators, independent contractors and subcontractors, and employees of these contractors) to perform on a pipeline system an operation, maintenance or emergency-response function regulated by this rule unless that individual has been trained and successfully completed a test designed to demonstrate possession of the knowledge and skills under paragraph (12)(D)2. The test shall be

written, hands-on, or oral, or any combination of these methods. For some functions, a test might consist of observing on-the-job performance supplemented by appropriate queries. An individual who does not meet these requirements may be permitted to perform such a function when directly supervised by someone who has properly met the requirements for qualifications.]

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;

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.

[2.] **4.** Personnel to whom this **subsection** applies must *[be trained]* **possess the knowledge and skills necessary** to —

A. *[Perform]* **Follow** the requirements of this rule that relate to *[their assigned functions]* **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 *[their assigned functions]* **the covered tasks they perform;**

C. Utilize instruments and equipment that relate to *[their assigned functions]* **the covered tasks they perform** in accordance with manufacturer's instructions;

D. Know the characteristics and hazards of the gas transported, including flammability range, *[and toxicity, olfactory]* **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 *[or toxicity]*; 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.

[3. At intervals of not more than three (3) years, personnel to whom this section applies who are previously qualified under paragraph (12)(D)1. must attend training to refresh their knowledge and skills required under paragraph (12)(D)2. Except that individuals such as welders and persons who join plastic pipe who are requalified under other subsections of this rule are not required to attend the training required by subparagraph (12)(D)2.A.

4. Each operator shall keep personnel to whom this subsection applies informed of any changes to this rule and the procedural manual for operations, maintenance and emergencies that relate to their assigned functions, and incorporate those changes in training provided under this subsection.]

5. Each operator shall *[annually review with operating and maintenance personnel their performance in meeting the objectives of the training program at intervals not exceeding fifteen (15) months.]* **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 *[require and verify that]* **provide instruction to the** supervisors *[maintain a thorough knowledge of that portion of the procedures required by this subsection for which they are responsible to ensure compliance]* **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.

[7] **8. Recordkeeping. (192.807)** Each operator shall maintain records that demonstrate **compliance with this subsection.** *[that personnel have been qualified as required by paragraph (12)(D)1. and attended training as required by paragraph (12)(D)3.]*

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) Dates(s) of current qualification; and

(IV) Qualification method(s).

B. *[The records must be maintained during that individual's employment and for at least three (3) years thereafter.]* **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.

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

(I) Damage Prevention Program (192.614).

1. Except for pipelines listed in *[paragraph (12)(I)5.]* **paragraphs (12)(I)6. and 7.**, each operator of a buried pipeline shall carry out in accordance with this subsection a written program to prevent damage to that pipeline by excavation activities. For the purpose of this subsection, excavation activities include excavation, blasting, boring, tunneling, backfilling, *[and]* the removal of aboveground structures by either explosive or mechanical means, and other *[earth moving]* **earthmoving** operations. Particular attention should be given to excavation activities in close proximity to cast iron mains with remedial actions taken as required by subsection (13)(Z). (192.755) *[An operator may perform any of the duties required by paragraph (12)(I)2. through participation in a public service program, such as a one call system but such participation does not relieve the operator of responsibility for compliance with this subsection.]*

2. An operator may perform any of the duties required by paragraph (12)(I)3. through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this subsection. However, an operator

must perform the duties of subparagraph (12)(I)3.D. through participation in the qualified one-call system for Missouri. An operator's pipeline system must be covered by the qualified one-call system for Missouri.

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

A. Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located. A listing of persons involved in excavation activities shall be maintained and updated at least once each calendar year with intervals not exceeding fifteen (15) months. If an operator chooses to participate in an excavator education program of a one-call notification center, as provided for in subparagraphs *[(12)(I)2.B. and C.]* **(12)(I)3.B and C.**, then such updated listing shall be provided to the one-call notification center prior to December 1 of each calendar year. This list should at least include, but not be limited to, the following:

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

(II) Telephone company;

(III) Electric utilities and co-ops;

(IV) Water and sewer utilities;

(V) City governments;

(VI) County governments;

(VII) Special road districts:

(VIII) Special water and sewer districts; and

(IX) Highway department district(s);

B. Provide for at least a semi-annual general notification of the public in the vicinity of the pipeline. Provide for actual notification of the persons identified in subparagraph *[(12)(I)2.A.]* **(12)(I)3.A.**, at least once each calendar year at intervals not exceeding fifteen (15) months by registered or certified mail, or notification through participation in an excavator education program of a one-call notification center meeting the requirements of subparagraph *[(12)(I)2.C.]* **(12)(I)3.C.** Mailings to excavators shall include a copy of the applicable sections of Chapter 319, RSMo, or a summary of the provisions of Chapter 319, RSMo approved by designated commission personnel, concerning underground facility safety and damage prevention pertaining to excavators. The operator's public notifications and excavator notifications shall include information concerning the existence and purpose of the operator's damage prevention program, as well as information on how to learn the location of underground pipelines before excavation activities are begun;

C. In order to provide for an operator's compliance with the excavator notification requirements of subparagraph *[(12)(I)2.B.]* **(12)(I)3.B.**, a one-call system's excavator education program must:

(I) Maintain and update a comprehensive listing of excavators who use the one-call notification center and who are identified by the operators pursuant to the requirements of subparagraph *[(12)(I)2.A.]* **(12)(I)3.A.**;

(II) Provide for at least semi-annual educational mailings to the excavators named on the comprehensive listing maintained pursuant to *[(12)(I)2.C.(I)]* **part (12)(I)3.C.(I)**, by first class mail; and

(III) Provide for inclusion of the following in at least one (1) of the semi-annual mailings required by part *[(12)(I)2.C.(II)]* **(12)(I)3.C.(II)**: Chapter 319, RSMo or a summary of the provisions of Chapter 319, RSMo approved by designated commission personnel, concerning underground facility safety and damage prevention which pertain to excavators; an explanation of the types of temporary markings normally used to identify the approximate location of underground facilities; and a description of the availability and proper use of the one-call system's notification center;

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

E. Include maintenance of records for subparagraphs *[(12)(I)2.B.-D.]* **(12)(I)3.B.-D.** as follows:

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

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

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

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

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

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

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

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

[3.] **4.** Each notification identified in subparagraph *[(12)(I)2.D.]* **(12)(I)3.D.** should be evaluated to determine the need for and the extent of inspections. The following factors should be considered in determining the need for and extent of those inspections:

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

B. The proximity to the operator's facilities;

C. The type of excavating equipment involved;

D. The importance of the operator's facilities;

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

F. The potential for serious incident should damage occur;

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

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

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

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

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

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

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

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

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

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

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 *[(1)]* of the following pressures is to be used as design pressure:

(I) Eighty percent (80%) of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factor in (12)(M)1.B.(II); or

(II) If the pipe is twelve and three-quarter inches (12 ¾") **{324 mm}** or less in outside diameter and is not tested to yield under this paragraph, two hundred (200) psi*[g]* **{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 *[one point-five (1.5)]* **1.5**; and

(II) For steel pipe operated at one hundred (100) psi*[g]* **{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

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

C. The highest actual operating pressure to which the segment was subjected during the five (5) years preceding July 1, 1970, unless the segment was tested in accordance with subparagraph (12)(M)1.B. after July 1, 1965, or the segment was uprated in accordance with section (11); and

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). (192.611)

(N) Maximum Allowable Operating Pressure–High-Pressure Distribution Systems. (192.621)

1. No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

A. The design pressure of the weakest element in the segment, determined in accordance with sections (3) and (4);

B. Sixty (60) psi*[g]* **{414 kPa} gauge**, for a segment of a distribution system otherwise designated to operate at over sixty (60) psi*[g]* **{414 kPa} gauge**, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of subsection (4)(DD) (192.197[c]);

C. Twenty-five (25) psi*[g]* **{172 kPa} gauge** in segments of cast iron pipe in which there are unreinforced bell and spigot joints;

D. The pressure limits to which a joint could be subjected without the possibility of its parting; and

E. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

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

(13) Maintenance.

(E) Line Markers for Mains and Transmission Lines. (192.707)

1. Buried pipelines. Except as provided in paragraph (13)(E)2., a line marker must be placed and maintained as close as practical over each buried main and transmission line–

A. At each crossing of a public road or railroad. Some crossings may require markers to be placed on both sides due to visibility limitations or crossing widths; and

B. Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

2. Exceptions for buried pipelines. Line markers are not required for the following buried pipelines–

A. Mains and transmission lines located at crossings of or under waterways and other bodies of water;

B. Feeder lines and transmission lines located in Class 3 or Class 4 locations where placement of a marker is impractical; or

C. Mains other than feeder lines in Class 3 or Class 4 locations where a damage prevention program is in effect under (12)(I).

3. Pipelines aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located above ground.

4. Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker:

A. The word "Warning," "Caution" or "Danger," followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch (1") **{25 millimeters}** high with one-quarter inch (1/4") **{6.4 millimeters}** stroke; and

B. The name of the operator and telephone number (including area code) where the operator can be reached at all times.

(F) Record Keeping.

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 re-evaluation 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 F 7100.1-1 and RSPA F 7100.2-1); *[and]*

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

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

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

(G) Transmission Lines–General Requirements for Repair Procedures. (192.711)

1. Each operator shall take immediate temporary measures to protect the public whenever–

A. A leak, imperfection or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above forty percent (40%) of the SMYS; and

B. It is not feasible to make a permanent repair at the time of discovery. As soon as feasible the operator shall make permanent repairs.

2. Except as provided in subparagraph *[(13)(J)1.C. (192.717[a][3])]* **(13)(J)2.C. (192.717[b][3])**, no operator may use a welded patch as a means of repair.

(H) Transmission Lines–Permanent Field Repair of Imperfections and Damages. (192.713)

1. *[Except as provided in paragraph (13)(H)2., each]* **Each** imperfection or damage that impairs the serviceability of *[a segment of]* **pipe in a** steel transmission line operating at or above forty percent (40%) of SMYS must be*[repaired as follows:]* –

A. *[If it is feasible to take the segment out of service, the imperfection or damage must be removed]* **Removed** by cutting out **and replacing** a cylindrical piece of pipe*[and replacing it with pipe of similar or greater design strength]*; **or**

B. *[If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design must be applied over the imperfection or damage; and]* **Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.**

2. *[C. If the segment is not taken out of service, the operating]* **Operating** pressure must be *[reduced to]* **at** a safe level during *[the]* repair operations.

[2. Submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the imperfection or damage.]

(I) Transmission Lines–Permanent Field Repair of Welds. (192.715) Each weld that is unacceptable under paragraph (5)(I)3. (192.241[c]) must be repaired as follows:

1. If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of subsection (5)(K) (192.245);

2. A weld may be repaired in accordance with subsection (5)(K) (192.245) while the segment of transmission line is in service if–

A. The weld is not leaking;

B. The pressure in the segment is reduced so that it does not produce a stress that is more than twenty percent (20%) of the SMYS of the pipe; and

C. Grinding of the defective area can be limited so that at least one-eighth inch (1/8") **{3.2 millimeters}** thickness in the pipe weld remains; and

3. A defective weld which cannot be repaired in accordance with paragraph (13)(I)1. or 2. must be repaired by installing a full encirclement welded split sleeve of appropriate design.

(J) Transmission Lines–Permanent Field Repair of Leaks. (192.717) *[1. Except as provided in paragraph (13)(J) 2., each]* **Each** permanent field repair of a leak on a transmission line must be made *[as follows:]* **by–**

1. *[A. If feasible, the segment of transmission line must be taken out of service and repaired]* **Removing the leak** by cutting out **and replacing** a cylindrical piece of pipe*[and replacing it with pipe of similar or greater design strength]*; **or**

2. Repairing the leak by one of the following methods:

A. *[B. If it is not feasible to take the segment of transmission line out of service, repairs must be made by installing]* **Install** a full encirclement welded split sleeve of appropriate design, unless the transmission line *[–*

(I) Is] **is** joined by mechanical couplings*[;]* and *[*

(II) Operates] **operates** at less than forty percent (40%) of SMYS*[; and]*.

B. *[C.]* If the leak is due to a corrosion pit, *[the repair may be made by installing]* **install** a properly designed bolt-on-leak clamp *[or, if]*.

C. If the leak is due to a corrosion pit and on pipe of not more than forty thousand (40,000) psi **{276 MPa}** SMYS, *[the repair may be made by fillet welding]* **fillet weld** over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half (1/2) of the diameter of the pipe in size.

[2.] **D. If the leak is on a submerged** *[Submerged]* pipeline*[s]* in inland navigable waters, *[may be repaired by]* mechanically apply*[ing]* a full encirclement split sleeve of appropriate design *[over the leak]*.

E. Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(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 by 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. 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* 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, 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.

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.

(Q) Compressor Stations–Storage of Combustible Materials and Gas. (192.735 and 192.736)

1. Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

2. Aboveground oil or gasoline storage tanks must be protected in accordance with the *Flammable and Combustible Liquids Code*, ANSI/NFPA 30.

3. Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is–

A. Constructed so that at least fifty percent (50%) of its upright side area is permanently open; or

B. Located in an unattended field compressor station of one thousand (1,000) horsepower {746 kW} or less.

4. Except when shutdown of the system is necessary for maintenance under paragraph (13)(Q)5., each gas detection and alarm system required by this subsection must–

A. Continuously monitor the compressor building for a concentration of gas in air of not more than twenty-five percent (25%) of the lower explosive limit; and

B. If gas at that concentration is detected, warn persons about to enter the building and persons inside the building of the danger.

5. Each gas detection and alarm system required by this subsection must be maintained to function properly. The maintenance must include performance tests.

(W) Vault Maintenance. (192.749)

1. Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of two hundred (200) cubic feet **{5.66 cubic meters}** or more must be inspected at intervals not exceeding fifteen (15) months but at least once each calendar year to determine that it is in good physical condition and adequately ventilated.

2. If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

3. The ventilating equipment must also be inspected to determine that it is functioning properly.

4. Each vault cover must be inspected to assure that it does not present a hazard to public safety.

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

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

(14) Gas Leaks.

(B) Investigation and Classification Procedures.

1. Each operator-detected leak indication or any leak or odor call from the general public, police, fire or other authorities or notification of damage to facilities by contractors or other outside sources shall require immediate investigation and classification.

2. Investigation of each inside leak or odor notice shall include the use of gas detection equipment upon initial entry into the structure and during investigations within the structure. When investigating an outside leak or odor notice, special attention must be given to those situations where conditions could impair the venting of natural gas to the atmosphere or impair the ability of gas detection equipment to properly detect the presence of gas, such as excessive ground moisture, rain, snow, frozen soil or wind.

3. Investigation of underground leaks shall be conducted using gas detection equipment. Sampling of the subsurface atmosphere shall be done at sufficient intervals and locations to assure safety to persons and property in the immediate and adjacent area.

4. Except for obvious Class 1 leaks, all leak classifications shall be substantiated by the use of gas detection equipment.

5. A follow-up leak investigation shall be conducted immediately after the repair of each Class 1 or Class 2 leak, and continued as necessary, to determine the effectiveness of the repair and to assure all hazardous leaks in the affected area are corrected.

6. Whenever the operator conducts work on a customer's premise for any type of customer gas service order or call, including all *[premises]* **premise** odor calls, tests of the subsurface atmosphere must be made using gas detection equipment, except as noted below. At least one *[(1)]* test must be made at a location where the buried service line or yard line is near the structure; for copper service lines, at least one *[(1)]* additional test must be made at the customer's property line, approximately one hundred feet (100') from the structure, or at the service tap at the main, whichever is closest to the structure. In lieu of conducting the tests of the subsurface atmosphere, the operator may conduct a leak survey of this pipe with gas detection equipment capable of detecting gas concentrations of three hundred (300) parts per million, gas-in-air. These tests are not required for collections, discontinuance of service for nonpayment, meter readings, read-ins/read-outs, line locations, atmospheric corrosion protection work or general painting, when relighting after emergency outages or curtailments, when lighting customer pilot lights *[as part of a pilot lighting program]*, cathodic protection work, or if leak tests have been conducted at the location within the previous fifteen (15) months.

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 x, 2000.***

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: Anyone may file comments in support of or in opposition to this Proposed Amendment with the Missouri Public Service Commission, Dale Hardy Roberts, Secretary, P.O. Box 360, Jefferson City, MO 65102. To be considered, comments must be received within thirty days after publication of this notice in the ***Missouri Register****. Comments should refer to Case No. GX-2001-91 and be filed with an original and eight (8) copies. No public hearing is scheduled.*

Appendix A–Incorporated by Reference

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

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-*[95a]* **96**).

2) ASTM Designation A 106 *Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service* (A 106-*[94a]* **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-*[95]* **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-*[95c]* **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).

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)** (*[1991]* **1996**).

F. National Fire Protection Association (NFPA):

1) ANSI/NFPA 30 *Flammable and Combustible Liquids Code* (*[1993]* **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–Qualification of Pipe

I. Listed Pipe Specifications. Numbers in parentheses indicate applicable editions.

API 5LXSteel pipe (1995).

ASTM A 53XSteel pipe (*[1995a]* **1996**).

ASTM A 106XSteel pipe (*[1994a* **1995**).

ASTM A 333/A 333MXSteel pipe (1994).

ASTM A 381XSteel pipe (1993).

ASTM A 671XSteel pipe (1994).

ASTM A 672XSteel pipe (1994).

ASTM A 691XSteel pipe (1993).

ASTM D 2513XThermoplastic pipe and tubing (*[1995c]* **1996a**).

ASTM D 2517XThermosetting 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, 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 *[(1)]* test weld must be made for each one hundred (100) lengths of pipe. On pipe four inches (4") **{102 millimeters}** or less in diameter, at least one *[(1)]* test weld must be made for each four hundred (400) lengths of pipe. The weld must be tested in accordance with API Standard 1104. 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*. 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. 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 *[(1)]* section of overhead position welding. The beveling, root opening and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four *[(4)]* coupons and subjected to a root bend test. If, as a result of this test, two *[(2)]* or more of the four *[(4)]* coupons develop a crack in the weld material, or between the weld material and base metal, that is more than one-eighth inch (1/8") **{3.2 millimeters}** long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

III. Periodic tests for welders of small service lines. Two *[(2)]* samples of the welder's work, each about eight inches (8") **{203 millimeters}** long with the weld located approximately in the center, are cut from steel service line and tested as follows:

1) One *[(1)]* sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of two inches (2") **{51 millimeters}** on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable; and

2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in paragraph III. 1) of this appendix.

Appendix E to 4 CSR 240-40.030

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

4 CSR 240-40.030(8) Customer Meters, Service Regulators and Service Lines
- (A) Scope, Compliance with Specifications or Standards, and Inspections. (192.351)
- (B) Service Lines and Yard Lines.
- (C) Customer Meters and Regulators–Location. (192.353)
- (D) Customer Meters and Regulators–Protection From Damage. (192.355)
- (E) Customer Meters and Regulators–Installation. (192.357)

(F) Customer Meter Installations–Operating Pressure. (192.359)
(G) Service Lines–Installation. (192.361)
(H) Service Lines–Valve Requirements. (192.363)
(I) Service Lines–Location of Valves. (192.365)
(J) Service Lines–General Requirements for Connections to Main Piping. (192.367)
(K) Service Lines–Connections to Cast Iron or Ductile Iron Mains. (192.369)
(L) Service Lines–Steel. (192.371)
(M) Service Lines–Plastic. (192.375)
(N) New Service Lines Not in Use. (192.379)
(O) Service Lines–Excess Flow Valve Performance Standards. (192.381)
(P) Excess Flow Valve Customer Notification. (192.383)

4 CSR 240-40.030(10) Test Requirements
(A) Scope. (192.192.501)
(B) General Requirements. (192.503)
(C) Strength Test Requirements for Steel Pipeline to Operate at a Hoop Stress of Thirty Percent (30%) or More of SMYS. (192.505)
(D) Test Requirements for Pipelines to Operate at a Hoop Stress Less Than Thirty Percent (30%) of SMYS and at or Above One Hundred (100) psi*[g]* **{689 kPa} gauge**. (192.507)
(E) Test Requirements for Pipelines to Operate Below One Hundred (100) psi*[g]* **{689 kPa} gauge**. (192.509)
(F) Test Requirements for Service Lines. (192.511)
(G) Test Requirements for Plastic Pipelines. (192.513)
(H) Environmental Protection and Safety Requirements. (192.515)
(I) Records. (192.517)
(J) Test Requirements for Customer-Owned Fuel Lines.

4 CSR 240-40.030(12) Operations.
(A) Scope. (192.601)
(B) General Provisions. (192.603)
(C) Procedural Manual for Operations, Maintenance, and Emergencies. (192.605)
(D) *[Personnel]* Qualification **of Pipeline Personnel (Subpart N).**
(E) *Reserved* (192.607)
(F) Change in Class Location–Required Study. (192.609)
(G) Change in Class Location–Confirmation or Revision of Maximum Allowable Operating Pressure. (192.611)
(H) Continuing Surveillance. (192.613)
(I) Damage Prevention Program. (192.614)
(J) Emergency Plans. (192.615)
(K) Public Education. (192.616)
(L) Investigation of Failures. (192.617)
(M) Maximum Allowable Operating Pressure–Steel or Plastic Pipelines. (192.619)
(N) Maximum Allowable Operating Pressure–High-Pressure Distribution Systems. (192.621)
(O) Maximum and Minimum Allowable Operating Pressure–Low-Pressure Distribution Systems. (192.623)
(P) Odorization of Gas. (192.625)
(Q) Tapping Pipelines Under Pressure. (192.627)
(R) Purging of Pipelines. (192.629)
(S) Providing Service to Customers.

Certificate of Service

I hereby certify that copies of the foregoing have been mailed or hand-delivered to all counsel of record as shown on the attached service list this 15th day of December 2000.

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Service List for
Case No. GX-2001-91
Revised: December 15, 2000 (lb)

Office of the Public Counsel
PO Box 7800
Jefferson City, MO 65102