Rules of

Department of Economic Development

Division 240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

Title 4—DEPARTMENT OF ECONOMIC DEVELOPMENT
Division 240—Public Service Commission
Chapter 40—Gas Utilities and Gas Safety Standards

4 CSR 240-40.010 Rate Schedules

PURPOSE: This rule prescribes the forms and procedures for filing and publishing schedules of rates of all gas utilities under the jurisdiction of the Public Service Commission.

(1) Every gas corporation engaged in the manufacture, furnishing or distribution of gas of any nature whatsoever for light, heat or power, within the state of Missouri, is directed not later than October 15, 1913, to have on file with this commission and keep open for public inspection, schedules showing all rates and charges in connection with such service of whatever nature made by the gas corporations for each and every kind of service which it renders as were in force on April 15, 1913, together with proper supplements covering all changes in the rate schedules authorized by this commission, if any, since April 15, 1913.

(2) All such rate schedules now on file with the commission not in accordance with this rule shall be issued in the form and manner prescribed by this rule and all rate schedules issued after April 15, 1913, must conform to this rule.

(3) Rate schedules shall be drawn up substantially in accordance with Form No. 14 and shall be plainly printed or typewritten on good quality of paper of size eight and one-half inches by eleven inches (8 1/2" × 11") in book, sheet or pamphlet form. A loose-leaf plan may be used so changes can be made by reprinting and inserting a single leaf. When the loose-leaf plan is used, all sheets, except the title page sheet, must show in the marginal space at the top of the page the name of the gas corporation issuing, the PSC number of schedule and the number of the page. In the marginal space at the bottom of sheet should be shown—the date of issue, the effective date and the name, title and address of the officer by whom the schedule is issued. All schedules shall bear a number with the prefix PSC Mo._______. Schedules shall be numbered in consecutive serial order beginning with number 1 for each gas corporation. If a schedule or part of a schedule is cancelled, a new schedule or part thereof (sheet(s) if loose-leaf) will refer to the schedule canceled by its PSC number; thus: PSC Mo. No.__________cancelling PSC Mo. No.___________.

(4) Each schedule shall be accompanied by a letter of transmittal, in duplicate if receipt is desired, in the following form:

LETTER OF TRANSMITTAL

____
(Name of gas corporation)
*(Date)*______________________________

To the Public Service Commission, State of Missouri, Jefferson City:
Accompanying schedule issued by the _____________ is sent you for filing in compliance with the requirements of the Public Service Commission Law.
PSC Mo. No._____________________.
Sup. No. ______________ to PSC Mo. No._____________.
Effective,_______________, 19________.

____
(Signature and title of filing officer)

(5) All proposed changes in rates, charges or rentals or in rules that affect rates, charges or rentals filed with the commission shall be accompanied by a brief summary, approximately one hundred (100) words or less of the effect of the change on the company's customers. A copy of any proposed change and summary shall also be served on the public counsel and be available for public inspection and reproduction during regular office hours at the general business office of the utility.

(6) Thirty (30) days' notice to the commission is required as to every publication relating to gas rates or service except where publications are made effective on less than statutory notice by permission, rule or requirement of the commission.

(7) Except as is otherwise provided, no schedule or supplement will be accepted for filing unless it is delivered to the commission free from all charges or claims for postage, the full thirty (30) days required by law before the date upon which the schedule or supplement is stated to be effective. No consideration will be given to or for the time during which a schedule or supplement may be held by the post office authorities because of insufficient postage. When a schedule or a supplement is issued and as to which the commission is not given the statutory notice, it is as if it had not been issued and a full statutory notice must be given of any reissuance. No consideration will be given to telegraphic notices in computing the thirty (30) days' notice required. In those cases the schedule will be returned to the sender and correction of the neglect or omission cannot be made which takes into account any time elapsing between the date upon which the schedule or supplement was received and the date of the attempted correction. For rate schedules and supplements issued on short notice under special permission of the commission, literal compliance with the requirements for notice named in any order, rule or permission granted by the commission will be exacted.

AUTHORITY: section 393.140(11), RSMo 1986. Original rule filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed May 16, 1977, effective Dec. 11, 1977. Amended: Filed May 29, 1986, effective Oct. 27, 1986.*

**Original authority 1939, amended 1949, 1967.*

4 CSR 240-40.017 HVAC Services Affiliate Transactions

PURPOSE: This rule prescribes the requirements for HVAC services affiliated entities and regulated gas corporations when such gas corporations participate in affiliated transactions with an HVAC affiliated entity as set forth in sections 386.754, 386.756, 386.760, 386.762 and 386.764, RSMo by the General Assembly of the State of Missouri.

(1) Definitions.
(A) Affiliated entity means any entity not regulated by the Public Service Commission which is owned, controlled by or under common control with a utility and is engaged in HVAC services.
(B) Control (including the terms "controlling," "controlled by," and "common control") means the possession, directly or indirectly, of the power to direct, or to cause the direction of the management or policies of an entity, whether such power is exercised through one (1) or more intermediary entities, or alone, or in conjunction with, or pursuant to an agreement with, one (1) or more other entities, whether such power is exercised through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, affiliated entities, contract or any other direct or indirect means. The commission shall presume that the beneficial ownership of more than ten percent (10%) of voting securities or partnership interest of an entity confers control for purposes of this rule. This provision, however, shall not be construed to prohibit a regulated gas corporation from rebutting the presumption that its

ownership interest in an entity confers control.

(C) Fully distributed cost means a methodology that examines all costs of an enterprise in relation to all the goods and services that are produced. Fully distributed cost requires recognition of all costs incurred directly or indirectly used to produce a good or service. Costs are assigned either through a direct or allocated approach. Costs that cannot be directly assigned or indirectly allocated (e.g. general and administrative) must also be included in the fully distributed cost calculation through a general allocation.

(D) HVAC services means the warranty, sale, lease, rental, installation, construction, modernization, retrofit, maintenance or repair of heating, ventilating and air conditioning (HVAC) equipment.

(E) Regulated gas corporation means a gas corporation as defined in section 386.020, RSMo, subject to commission regulation pursuant to Chapter 393, RSMo.

(F) Utility contractor means a person, including an individual, corporation, firm, incorporated or unincorporated association or other business or legal entity, that contracts, whether in writing or not in writing, with a regulated gas corporation to engage in or assist any entity in engaging in HVAC services, but does not include employees of a regulated gas corporation.

(2) A regulated gas corporation may not engage in HVAC services, except by an affiliated entity, or as provided in sections (8) and (9) of this rule.

(3) No affiliated entity or utility contractor may use any vehicles, service tools, instruments, employees, or any other regulated gas corporation assets, the cost of which are recoverable in the regulated rates for regulated gas corporation service, to engage in HVAC services unless the regulated gas corporation is compensated for the use of such assets at the fully distributed cost to the regulated gas corporation.

(A) The determination of a regulated gas corporation's cost in this section is defined in subsection (1)(D) of this rule.

(4) A regulated gas corporation may not use or allow any affiliated entity or utility contractor to use the name of such regulated gas corporation to engage in HVAC services unless the regulated gas corporation, affiliated entity or utility contractor discloses, in plain view and in bold type on the same page as the name is used on all advertisements or in plain audible language during all solicitations of such services, a disclaimer that states the services provided are not regulated by the commission.

(5) A regulated gas corporation may not engage in or assist any affiliated entity or utility contractor in engaging in HVAC services in a manner which subsidizes the activities of such regulated gas corporation, affiliated entity or utility contractor to the extent of changing the rates or charges for the regulated gas corporation's services above or below the rates or charges that would be in effect if the regulated gas corporation were not engaged in or assisting any affiliated entity or utility contractor in engaging in such activities.

(6) Any affiliated entities or utility contractors engaged in HVAC services shall maintain accounts, books and records separate and distinct from the regulated gas corporation.

(7) The provisions of this rule shall apply to any affiliated entity or utility contractor engaged in HVAC services that is owned, controlled or under common control with the regulated gas corporation providing regulated services in the state of Missouri or any other state.

(8) A regulated gas corporation engaging in HVAC services in the state of Missouri five (5) years prior to August 28, 1998, may continue providing, to existing as well as new customers, the same type of services as those provided by the regulated gas corporation five (5) years prior to August 28, 1998.

(A) To qualify for this exemption, the regulated gas corporation shall file a pleading before the commission for approval.

1. The commission may establish a case to determine if the regulated gas corporation qualifies for an exemption under this rule.

(9) The provisions of this section shall not be construed to prohibit a regulated gas corporation from providing emergency service, providing any service required by law or providing a program pursuant to an existing tariff, rule or order of the commission.

AUTHORITY: sections 386.760.1, RSMo Supp. 1998 and 393.140, RSMo 1994. Original rule filed Dec. 17, 1998, effective Aug. 30, 1999.*

**Original authority 386.710.1, RSMo 1998 and 393.140, RSMo 1939, amended 1949, 1967.*

4 CSR 240-40.020 Incident, Annual and Safety-Related Condition Reporting Requirements

PURPOSE: This rule prescribes requirements and procedures for reporting certain gas-related incidents and safety-related conditions, and for filing annual reports. It applies to gas systems subject to the safety jurisdiction of the Public Service Commission.

Editor's Note: The secretary of state has determined that the publication of this rule in its entirety would be unduly cumbersome or expensive. The entire text of the material referenced has been filed with the secretary of state. This material may be found at the Office of the Secretary of State or at the headquarters of the agency and is available to any interested person at a cost established by state law. This rule is similar to the Minimum Federal Safety Standards contained in 49 CFR part 191, ***Code of Federal Regulations****. Parallel citations to part 191 are provided for gas operator convenience and to promote public safety. RSPA Forms referenced in this rule are available in both the Office of the Secretary of State and the Gas Safety Section, Missouri Public Service Commission.*

(1) Scope. (191.1)

(A) This rule prescribes requirements for the reporting of incidents, safety-related conditions and annual pipeline summary data by operators of gas pipeline facilities located in Missouri and under the jurisdiction of the commission.

(B) This rule does not apply to onshore gathering of gas 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.

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

(A) Administrator means the administrator of the RSPA or any person to whom authority in the matter concerned has been delegated by the Secretary of the United States Department of Transportation;

(B) Commission means the Public Service Commission, Designated commission personnel means the Pipeline Safety Program Manager at the address contained in section (5) (191.7) for required correspondence and means the list of staff personnel supplied to the operators for required telephonic notices;

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

1. An event that involves a release of gas from a pipeline or of liquefied natural gas (LNG) or gas from an LNG facility and—

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

B. Estimated property damage, including cost of gas lost, of the operator or others, or both, of fifty thousand dollars ($50,000) or more;

2. An event that results in an emergency shutdown of an LNG facility; or

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

(D) Gas means natural gas, flammable gas, manufactured gas or gas which is toxic or corrosive;

(E) LNG facility means a liquefied natural gas facility as defined in 193.2007 of 49 CFR part 193;

(F) Master meter system means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, for instance, by rents;

(G) Municipality means a city, village or town;

(H) Operator means a person who engages in the transportation of gas;

(I) Person means any individual, firm, joint venture, partnership, corporation, association, county, state, municipality, political subdivision, cooperative association or joint stock association, and includes any trustee, receiver, assignee or personal representative of them;

(J) Pipeline or pipeline system means all parts of those physical facilities through which gas moves in transportation including, but not limited to, pipe, valves and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders and fabricated assemblies;

(K) RSPA means the Research and Special Programs Administration of the United States Department of Transportation; and

(L) Transportation of gas means the gathering, transmission or distribution of gas by pipeline, or the storage of gas in or affecting interstate or foreign commerce.

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

(A) At the earliest practicable moment following discovery, each operator shall give notice, in accordance with subsection (3)(B), of each federal incident as defined in section (2) (191.3).

(B) Each notice required by subsection (3)(A) shall be made by telephone to 800-424-8802 and shall include the following information:

1. Names of operator and person making report and their telephone numbers;

2. Location of the incident;

3. Time of the incident;

4. Number of fatalities and personal injuries, if any; and

5. All other significant facts known by the operator that are relevant to the cause of the incident or extent of the damages.

(4) Missouri Reporting Requirements.

(A) Within two (2) hours following discovery by the operator, or as soon thereafter as practicable if emergency efforts to protect life and property would be hindered, each gas operator shall notify designated commission personnel by telephone of the following events within areas served by the operator:

1. An event that involves a release of gas involving the operator's actions or facilities, or where there is a suspicion by the operator that the event may involve a release of gas involving the operator's actions or facilities, and involves—

A. A death;

B. A personal injury involving medical care administered in an emergency room or health care facility, whether inpatient or outpatient, beyond initial treatment and prompt release after evaluation by a health care professional; or

C. Estimated property damage, including cost of gas lost, to the gas operator or others, or both, of ten thousand dollars ($10,000) or more; or

2. An event that is significant, in the judgement of the operator, even though it did not meet the criteria of paragraph (4)(A)1.

(B) Exceeding the two (2)-hour notification time period in (4)(A) requires submission of a written explanation of reasons with the operator's incident report.

(C) Within thirty (30) days of a telephonic notification made under subsection (4)(A), each gas operator shall submit U.S. Department of Transportation Form RSPA F 7100.1 or RSPA F 7100.2, as applicable, to designated commission personnel. A copy of both incident report forms is printed at the end of this rule. An incident report is required when an event causes the criteria listed in paragraphs (4)(A)1. or 2. to be met. Additional information required in subsections (6)(B) and (9)(B) (191.9[b] and 191.15[b]) shall apply.

(D) Federal incident and annual reports required by this rule shall be submitted in duplicate to designated commission personnel as follows:

1. Federal incident reports required by section(s) (6) or (9), or both, (191.9 or 191.15, or both) shall be submitted as soon as practicable but not more than thirty (30) days after detection of the incident. Upon receipt and processing of these reports, the designated commission personnel, within ten (10) days, shall transmit one (1) copy to the Information Resources Manager at RSPA; and

2. Annual reports required by section(s) (7) or (10), or both, (191.11 or 191.17, or both) shall be submitted no later than February 28 of each year. Upon receipt and processing of these reports, the designated commission personnel shall transmit one (1) copy by March 15 to the Information Resources Manager at RSPA.

(E) Safety-related condition reports required by section (12) (191.23) shall be submitted concurrently to the Associate Administrator, Office of Pipeline Safety at RSPA and to designated commission personnel. A safety-related condition report can be submitted to the addresses provided in section (5) (191.7) or by telefacsimile (fax) as provided for in section (13).

(5) Addressee for Written Reports. (191.7) Incident, annual and safety-related condition reports shall be submitted to designated commission personnel as required by section (4). The address for the designated commission personnel is Pipeline Safety Program Manager, Missouri Public Service Commission, P.O. Box 360, Jefferson City, MO 65102. As required by subsection (4)(E), safety-related condition reports must be submitted concurrently to the Associate Administrator, Office of Pipeline Safety at RSPA by mail or by telefacsimile (fax). If submitted by mail, the address is Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 8417, 400 Seventh Street S.W., Washington, D.C. 20590. Safety-related condition reports may be submitted by fax as provided for in section (13).

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

(A) Except as provided in subsection (6)(C), each operator of a distribution pipeline system shall submit U.S. Department of Transportation Form RSPA F 7100.1 to designated commission personnel in accordance with subsection (4)(D) following each incident required to be reported under section (3). A copy of Form RSPA F 7100.1 is printed at the end of this rule.

(B) When additional relevant information is obtained after the report is submitted under subsection (6)(A), the operator shall make supplementary reports, as deemed necessary, with a clear reference by date and subject to the original report.

(C) The incident report required by this section need not be submitted with respect to master meter systems or LNG facilities.

(7) Distribution System—Annual Report. (191.11)

(A) Except as provided in subsection (7)(B), each operator of a distribution pipeline system shall submit an annual report for that system on U.S. Department of Transportation Form RSPA F 7100.1–1. This report must be submitted each year as required by section (4) for the preceding calendar year. A copy of Form RSPA F 7100.1–1 is printed at the end of this rule.

(B) The annual report required by this section need not be submitted with respect to—

1. Petroleum gas systems which serve fewer than one hundred (100) customers from a single source;

2. Master meter systems; or

3. LNG facilities.

(8) Distribution Systems Reporting Transmission Pipelines—Transmission or Gathering Systems Reporting Distribution Pipelines. (191.13) Each operator primarily engaged in gas distribution who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by sections (9) and (10) (191.15 and 191.17). Each operator primarily engaged in gas transmission or gathering who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by sections (6) and (7) (191.9 and 191.11).

(9) Transmission and Gathering Systems—Federal Incident Report. (191.15)

(A) Except as provided in subsection (9)(C), each operator of a transmission or a gathering pipeline system shall submit U.S. Department of Transportation Form RSPA F 7100.2 to designated commission personnel in accordance with subsection (4)(D) following each incident required to be reported under section (3). A copy of Form RSPA F 7100.2 is printed at the end of this rule.

(B) When additional related information is obtained after a report is submitted under subsection (9)(A), the operator shall make a supplemental report, as soon as practicable, with a clear reference by date and subject to the original report.

(C) The incident report required by subsection (9)(A) need not be submitted with respect to LNG facilities.

(10) Transmission and Gathering Systems—Annual Report. (191.17)

(A) Except as provided in subsection (10)(B), each operator of a transmission or a gathering pipeline system shall submit an annual report for that system on U.S. Department of Transportation Form RSPA F 7100.2–1. As required by section (4), this report must be submitted each year for the preceding calendar year. A copy of Form RSPA F 7100.2–1 is printed at the end of this rule.

(B) The annual report required by subsection (10)(A) need not be submitted with respect to LNG facilities.

(11) Report Forms. (191.19) Copies of the prescribed report forms are available without charge upon request from the Information Resource Manager's address given in section (5) (191.7). Additional copies in this prescribed format may be reproduced and used if in the same size and kind of paper. In addition, the information required by these forms may be submitted by any other means that is acceptable to the administrator. A copy of each report form is printed at the end of this rule.

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

(A) Except as provided in subsection (12)(B), each operator shall report in accordance with section (13) (191.25) the existence of any of the following safety-related conditions involving facilities in service:

1. In the case of the pipeline (other than an LNG facility) that operates at a hoop stress of twenty percent (20%) or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure and localized corrosion pitting to a degree where leakage might result;

2. Unintended movement or abnormal loading by environmental causes, for instance, an earthquake, landslide or flood, that impairs the serviceability of a pipeline or the structural integrity or reliability of an LNG facility that contains, controls or processes gas or LNG;

3. Any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls or processes gas or LNG;

4. Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of twenty percent (20%) or more of its specified minimum yield strength;

5. Any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the buildup allowed for operation of pressure limiting or control devices;

6. A leak in a pipeline or LNG facility that contains or processes gas or LNG that constitutes an emergency;

7. Inner tank leakage, ineffective insulation or frost heave that impairs the structural integrity of an LNG storage tank; and

8. Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a twenty percent (20%) or more reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes gas or LNG.

(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 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.

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

(A) Each report of a safety-related condition under subsection (12)(A) (191.23[a]) must be filed (received by the Associate Administrator, Office of Pipeline Safety at RSPA and designated commission personnel as required by subsection (4)(E)) in writing within five (5) working days (not including Saturday, Sunday or federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than ten (10) working days after the day a representative of the operator discovers the possibility of a condition. Separate conditions may be described in a single report if they are closely related. To file a report by telefacsimile (fax), dial (202)366-7128 for the Associate Administrator, Office of Pipeline Safety and (573) 751-1847 for designated commission personnel.

(B) The report must be titled Safety-Related Condition Report and provide the following information:

1. Name and principal address of the operator;
2. Date of report;
3. Name, job title and business telephone number of the person submitting the report;
4. Name, job title and business telephone number of the person who determined that the condition exists;
5. Date the condition was discovered and date the condition was first determined to exist;
6. Location of the condition, with reference to the state (and town, city, or county), and as appropriate, nearest street address, survey station number, milepost, landmark or name of pipeline;
7. Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored; and
8. The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

AUTHORITY: sections 386.250 and 386.310, RSMo Supp. 1997 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.*

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

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678.

Form Approved OMB No. 2137-0522

U.S. Department of Transportation
Research and Special Programs Administration

ANNUAL REPORT FOR CALENDAR YEAR 19____ GAS DISTRIBUTION SYSTEM

INITIAL REPORT ☐
SUPPLEMENTAL REPORT ☐

PART A – OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF COMPANY OR ESTABLISHMENT

____

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED

____
Number and Street

____
City and County

____
State and Zip Code

3. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (WHEN KNOWN)

/_/_/_/_/_/

4. HEADQUARTERS NAME & ADDRESS IF DIFFERENT

____

____

____

5. STATES IN WHICH SYSTEM OPERATES ________________________________

PART B – SYSTEM DESCRIPTION

Report miles of main and number of services in system at end of year

1. GENERAL

	STEEL				PLASTIC	CAST/WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	OTHER
	UNPROTECTED		CATHODICALLY PROTECTED							
	BARE	COATED	BARE	COATED						
MILES OF MAINS										
NO. OF SERVICES										

2. MILES OF MAINS IN SYSTEM AT END OF YEAR

MATERIAL	UNKNOWN	2" OR LESS	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8" THRU 12"	OVER 12"
STEEL						
DUCTILE IRON						
COPPER						
CAST/WROUGHT IRON						
PLASTIC 1. PVC						
2. PE						
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS						

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR

AVERAGE SERVICE LENGTH __________ FEET

MATERIAL	UNKNOWN	1" OR LESS	OVER 1" THRU 2"	OVER 2" THRU 4"	OVER 4" THRU 8"	OVER 8"
STEEL						
DUCTILE IRON						
COPPER						
CAST/WROUGHT IRON						
PLASTIC 1. PVC						
2. PE						
3. ABS						
OTHER						
OTHER						
SYSTEM TOTALS						

Form RSPA F 7100.1-1 (11-85)
(Supersedes DOT F 7100.1-1

Reproduction of this form is permitted.

PART C – TOTAL LEAKS		
CAUSE	ELIMINATED/REPAIRED DURING YEAR Mains	Services
CORROSION		
THIRD PARTY		
OUTSIDE FORCE		
CONSTRUCTION DEFECT		
MATERIAL DEFECT		
OTHER		
NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR	________	

PART D – TOTAL NUMBER OF LEAKS ON FEDERAL LAND REPAIRED OR SCHEDULED FOR REPAIR

____

PART E – PERCENT OF UNACCOUNTED FOR GAS

Unaccounted for gas as a percent of total

input for year ending 6/30 ____ %

PART F – ADDITIONAL INFORMATION

PART G – PREPARER AND AUTHORIZED SIGNATURE

________________________ / ________

Prepared by (type/print) telephone

________________________ / ________ ________________

Name and Title of Person Signing telephone Authorized Signature

U.S. Department
of Transportation

**Research and
Special Programs
Administration**

400 Seventh St. SW
Washington, DC 20590

Official Business
Penalty for Private Use $300

Postage and Fees Paid
Research and Special
Programs
Administration
DOT-513

U.S.MAIL

Information Resources Manager
Office of Pipeline Safety, DPS-3.3
Research and Special Programs Administration
400 7th Street, S.W.
Washington, D.C. 20590

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678.

Form Approved OMB No. 2137-0522

US Department of Transportation
Research and Special Programs Administration

INCIDENT REPORT – GAS DISTRIBUTION SYSTEM

Report Date ________
No. ________
(RSPA)

PART 1 – GENERAL REPORT INFORMATION

SEE INSTRUCTIONS

1. a. Operator's 5 digit Identification No. |_|_|_|_|_|
   b. Name of Operator ________
   c. ________ Number and Street
   d. ________ City, County, State and Zip Code
2. Location of Incident
   a. ________ Number and Street
   b. ________ City and County
   c. ________ State and Zip Code
   d. Class Location ☐ 1 ☐ 2 ☐ 3 ☐ 4
   e. Incident on Federal Land ☐ Yes ☐ No
3. Time and Date of Incident |_|_|_|_| hour |_|_| mo |_|_| day |_|_| yr
4. Reason for Reporting
   - ☐ Fatality Number |_|_|_| persons
   - ☐ Injury requiring inpatient hospitalization Number |_|_|_| persons
   - ☐ Property damage/loss Estimate $ ________
   - ☐ Operator Judgment/Emergency Action
   - ☐ Supplemental Report
5. Elapsed time until area was made safe |_|_| hr |_|_| mn
6. Telephonic Report: |_|_| mo |_|_| day |_|_| yr
7. a. Estimated pressure at point and time of incident *(PSIG)* ________
   b. Maximum allowable operating pressure *(MAOP) (PSIG)* ________
   c. MAOP established by:
      (1) Test pressure ________ *(PSIG)*
      (2) 49 CFR §192.619(a)(3) ☐

PART 2 – APPARENT CAUSE

- ☐ Corrosion *(Continue in Part A)*
- ☐ Damage by Outside Forces *(Continue in Part B)*
- ☐ Construction/Operating Error *(Continue in Part C)*
- ☐ Other ________
- ☐ Accidently caused by operator *(Continue in Parts B and/or C)*

PART 3 – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE INCIDENT

(Attach additional sheet(s) as necessary)

PART 4 – ORIGIN OF THE INCIDENT

1. Part of System Where Incident Occurred
   - ☐ Main
   - ☐ Service Line
   - ☐ Meter Set Assembly
   - ☐ Other ________
2. Component Which Failed
   a. Part
   - ☐ Body of Pipe
   - ☐ Joint, type ________
   - ☐ Fitting
   - ☐ Drip/Riser
   - ☐ Valve
   - ☐ Regulator/meter
   - ☐ Weld, specify ________ girth, longitudinal, fillet
   - ☐ Other ________
3. Material Involved:
   - ☐ Steel
   - ☐ Polyethylene plastic
   - ☐ Other ________
   - ☐ Cast iron
   - ☐ Other plastic: ________

   NPS *(Nominal Pipe Size)* |_|_|_|_| in. Wall Thickness |_|_|_|_| in.
4. Specification ________ Manufacturer ________ Year Manufactured |_|_|_|_| Year installed |_|_|_|_|

PART 5 – ENVIRONMENT

Area of Incident
- ☐ Within/Under Building
- ☐ Under Pavement
- ☐ Above Ground
- ☐ Under Ground or Under Water
- ☐ Other ________

PART 6 – PREPARER AND AUTHORIZED SIGNATURE

________ (type or print) Preparer's Name and Title

________ / ________ Telephone Number

________ Authorized Signature and Date

________ / ________ Telephone Number

Form RSPA F 7100.1 (3-84)

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PART A – CORROSION

1. Where did the corrosion occur?
   - ☐ Internally
   - ☐ Externally
2. Visual Description
   - ☐ Localized Pitting
   - ☐ General Corrosion
   - ☐ Other ____________
3. Cause
   - ☐ Galvanic
   - ☐ Other ____________
4. Pipe Coating Information
   - ☐ Bare ☐ Coated
5. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
   - ☐ Yes Year protection started /__/__/__/__/
   - ☐ No
6. Additional Information

PART B – DAMAGE BY OUTSIDE FORCES

1. Primary Cause of Incident
   - ☐ Damage resulted from action of operator or his agent
   - ☐ Damage resulted from action by outside party/third party
   - ☐ Damage by earth movement
     - ☐ Subsidence
     - ☐ Landslide/Washout
     - ☐ Frost
     - ☐ Other ____________
   - ☐ Damage by lightning or fire
2. Locating information (for damage resulting from action of outside party/third party)
   - a. Did operator get prior notification that equipment would be used in the area?
     - ☐ Yes Date received /__/__/ mo /__/__/ day /__/__/ yr
     - ☐ No
   - b. Was pipeline location marked either as a result of notification or by markers already in place?
     - ☐ Yes ☐ Permanent Markers ☐ Temporary Stakes ☐ Other ____________
     - ☐ No
   - c. Does Statute or ordinance require the outside party to determine whether underground facility(ies) exist?
     - ☐ Yes
     - ☐ No
3. Additional Information

PART C – CONSTRUCTION DEFECT

1. Cause
   - ☐ Poor Workmanship during Construction
   - ☐ Operating Procedure Inappropriate
   - ☐ Error in Operating Procedure Application
   - ☐ Physical Damage During Construction
   - ☐ Other ____________
2. Additional Information

PART D – OTHER

Brief Description:

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678.

Form Approved OMB No. 2137-0522

US Department of Transportation Research and Special Programs Administration

INCIDENT REPORT — GAS TRANSMISSION AND GATHERING SYSTEMS

Report Date ______
No. ______ (RSPA)

PART 1 — GENERAL REPORT INFORMATION

*SEE INSTRUCTIONS**

1. a. Operator's 5 digit identification no. /_/_/_/_/_/
   b. Name of Operator ______
   c. ______ Number and Street
   d. ______ City, County, State and Zip Code
2. Location of Incident
   a. ______ City and County
   b. ______ State and Zip Code
   c. Mile Post/Valve Stat. ______
   d. Survey Station No. ______
   e. Class Location
      Onshore ☐ 1 ☐ 2 ☐ 3 ☐ 4
      Offshore ☐ ______ area ______ block number
      State ______ or Outer Continental Shelf ______
   f. Incident on Federal Land other than Outer Continental Shelf
      ☐ Yes ☐ No
3. Incident Type
   ☐ Leak ☐ Rupture ☐ Other
   Rupture Length *(feet)* ______
4. Reason for Reporting
   ☐ Fatality — Number /_/_/_/ persons
   ☐ Injury requiring inpatient hospitalization — Number /_/_/_/ persons
   ☐ Property damage/loss — Estimated $ ______
   ☐ Operator Judgment
   ☐ Supplemental Report
5. Elapsed time until area was made safe
   /_/_/ hr /_/_/ mn
6. Telephonic Report
   /_/_/ mo /_/_/ day /_/_/ yr
7. a. Estimated Pressure at Point and Time of Incident *(PSIG)* ______
   b. Maximum allowable operating pressure *(MAOP) (PSIG)* ______
   c. MAOP established by:
      (1) Test pressure ______ *(PSIG)*
      (2) 49 CFR §192.619(a)(3) ☐
8. Time and Date of the Incident
   /_/_/_/_/ hour /_/_/ mo /_/_/ day /_/_/ yr

PART 2 — APPARENT CAUSE

☐ Corrosion *(Continue in Part A)*
☐ Damage by Outside Forces *(Continue in Part B)*
☐ Construction/Material Defect *(Continue in Part C)*
☐ Other ______

PART 3 — NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE INCIDENT

(Attach additional sheet(s) as necessary)

PART 4 — ORIGIN OF THE INCIDENT

1. Incident Occurred On:
   ☐ Transmission System ☐ Gathering System
   ☐ Transmission Line of Distribution System
2. Failure Occurred On:
   ☐ Body of Pipe ☐ Fitting, Specify ______
   ☐ Mechanical Joint ☐ Other, Specify ______
   ☐ Valve ☐ Weld, Specify ______ *(girth, longitudinal, fillet)*
3. Material Involved:
   ☐ Steel ☐ Other, Specify ______
4. Part of System Involved in Incident
   a. Part
      ☐ Pipeline ☐ Regulator/Metering System
      ☐ Compressor Station ☐ Other ______
   b. Year installed /_/_/_/_/

PART 5 — MATERIAL SPECIFICATION

1. Nominal Pipe Size /_/_/_/_/ in.
2. Wall Thickness /_/_/_/_/ in.
3. Specification ______ SMYS /_/_/_/_/_/
4. Seam Type ______
5. Valve, Type ______
6. Manufactured by ______ in year /_/_/_/_/

PART 6 — ENVIRONMENT

Area of Incident
☐ Under Pavement ☐ Above Ground
☐ Under Ground ☐ Under Water
☐ Other ______

PART 7 — PREPARER AND AUTHORIZED SIGNATURE

______ *(type or print)* Preparer's Name and Title
______ / ______ Telephone Number

______ Authorized Signature and Date
______ / ______ Telephone Number

Form RSPA F 7100.2 (3-84)

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PART A – CORROSION

1. Where did corrosion occur?
   ☐ Internally
   ☐ Externally
2. Visual Description
   ☐ Localized Pitting
   ☐ General Corrosion
   ☐ Other ____________
3. Cause
   ☐ Galvanic
   ☐ Other ____________
4. Pipe Coating Information
   ☐ Bare ☐ Coated
5. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
   ☐ Yes Year Protection Started /__/__/__/__/
   ☐ No
6. Additional Information

PART B – DAMAGE BY OUTSIDE FORCES

1. Primary Cause of Incident
   ☐ Damage resulted from action of operator or his agent
   ☐ Damage resulted from action by outside party/third party
   ☐ Damage by earth movement
      ☐ Subsidence
      ☐ Landslide/Washout
      ☐ Frost
      ☐ Other ____________
2. Locating information *(for damage resulting from action of outside party/third party)*
   a. Did operator get prior notification that equipment would be used in the area?
      ☐ Yes Date received /__/__/ mo /__/__/ day /__/__/ yr
      ☐ No
   b. Was pipeline location marked either as a result of notification or by markers already in place?
      ☐ Yes Specify type of marking: ____________
      ☐ No
   c. Does Statute or ordinance require the outside party to determine whether underground facility(ies) exist?
      ☐ Yes
      ☐ No
3. Additional Information

PART C – CONSTRUCTION OR MATERIAL DEFECT

1. Cause of Defect
   ☐ Construction ☐ Material *(describe in C.4 below)*
2. Description of Component Other than Pipe
3. Latest Test Data
   a. Was part which leaked pressure tested before incident occurred?
      ☐ Yes Date of Test /__/__/ mo /__/__/ day /__/__/ yr
      ☐ No
   b. Test Medium ☐ Water ☐ Gas ☐ Other ____________
   c. Time held at test pressure /__/__/ hr
   d. Estimated test pressure at point of incident *(psig)* ____________
4. Additional Information

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678.

Form Approved OMB No. 2137-0522

US Department of Transportation
Research and Special Programs Administration

ANNUAL REPORT FOR CALENDAR YEAR 19___
GAS TRANSMISSION & GATHERING SYSTEMS

INITIAL REPORT ☐
SUPPLEMENTAL REPORT ☐

PART A – OPERATOR INFORMATION

DOT USE ONLY

1. NAME OF COMPANY OR ESTABLISHMENT

____

2. LOCATION OF OFFICE WHERE ADDITIONAL INFORMATION MAY BE OBTAINED

____
Number & Street

____
City & County

____
State & Zip Code

3. STATES IN WHICH SYSTEM OPERATES ______________________

4. OPERATOR'S 5 DIGIT IDENTIFICATION NUMBER (WHEN KNOWN)

/ / / / / /

5. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT

____

____

____

PART B – SYSTEM DESCRIPTION

Report miles of pipeline in system at end of year

1. GENERAL – MILES OF PIPE

	STEEL				CAST IRON WROUGHT IRON PIPE UNPROTECTED	PLASTIC PIPE	OTHER PIPE
	CATHODICALLY PROTECTED		UNPROTECTED				
	BARE	COATED	BARE	COATED			
TRANSMISSION							
ONSHORE							
OFFSHORE							
GATHERING							
ONSHORE							
OFFSHORE							

2. MILES OF PIPE BY NOMINAL SIZE

	UNKNOWN	4" OR LESS	OVER 4" THRU 10"	OVER 10" THRU 20"	OVER 20" THRU 28"	OVER 28"
TRANSMISSION						
ONSHORE						
OFFSHORE						
GATHERING						
ONSHORE						
OFFSHORE						
SYSTEM TOTALS						

PART C – TOTAL LEAKS ELIMINATED/REPAIRED DURING YEAR

ITEMS	TRANSMISSION		GATHERING	
	ONSHORE	OFFSHORE	ONSHORE	OFFSHORE
CORROSION				
OUTSIDE FORCES				
CONST./MAT. DEFECTS				
OTHER				

PART D – TOTAL NUMBER OF LEAKS ON FEDERAL LAND OR OCS REPAIRED OR SCHEDULED FOR REPAIR

1. TRANSMISSION
   - ONSHORE ________
   - OFFSHORE ________
   - OUTER CONTINENTAL SHELF ________
2. GATHERING
   - ONSHORE ________
   - OFFSHORE ________
   - OUTER CONTINENTAL SHELF ________

PART E – NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR

1. TRANSMISSION ________
2. GATHERING ________

PART F – PREPARER AND AUTHORIZED SIGNATURE

______________________ / ________
Prepared by (type/print) telephone

______________________ / ________ ______________________
Name and Title Telephone Number Authorized Signature

Form RSPA F 7100.2-1 (11-85)
(Supersedes DOT F 7100.2-1

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Washington, D.C. 20590**

4 CSR 240-40.030 Safety Standards—Transportation of Gas by Pipeline

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

Publisher's Note: The publication of the full text of the material that the adopting agency has incorporated by reference in this rule would be unduly cumbersome or expensive. Therefore, the full text of that material will be made available to any interested person at both the Office of the Secretary of State and the office of the adopting agency, pursuant to section 536.031.4, RSMo. Such material will be provided at the cost established by state law. This rule is similar to the Minimum Federal Safety Standards contained in 49 CFR part 192, ***Code of State Regulations****. Parallel citations to Part 192 are provided for gas operator convenience and to promote public safety. Materials referenced in Appendices A-D are available in both the secretary of state's office and the Gas Safety Section, Missouri Public Service Commission. Appendix E, contained in this rule, is a Table of Contents for 4 CSR 240-40.030. These documents are also available at the addresses provided in the Appendices.*

(1) General.

(A) Scope of Rule. (192.1)

1. This rule prescribes minimum safety requirements for pipeline facilities and the transportation of gas in Missouri and under the jurisdiction of the commission.

2. This rule does not apply to—

A. The gathering of gas on private property outside of—

(I) An area within the limits of any incorporated or unincorporated city, town or village; or

(II) Any designated residential or commercial area such as a subdivision, business or shopping center or community development; or

B. Any pipeline system that transports only petroleum gas or petroleum gas/air mixture to—

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

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

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

1. 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. Building means any structure which is regularly or periodically occupied by people;

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

5. Feeder line means a distribution line that has a maximum allowable operating pressure greater than one hundred pounds per square inch gauge (100 psig), but produces hoop stresses less than twenty percent (20%) specified minimum yield strength (SMYS);

6. Follow-up inspection means an inspection performed after a repair procedure has been completed to determine the effectiveness of the repair and to insure 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 is 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 operations 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), 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);

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 at 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 on either side of the centerline of any continuous one (1)-mile length of pipeline; and

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

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

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

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

C. A Class 3 location is—

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

(II) An area where the pipeline lies within one hundred (100) yards of either a building or a small, well-defined outside area (for instance, 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 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 from the nearest building in the cluster.

(D) Incorporation By Reference. (192.7)

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

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

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

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

(F) Petroleum Gas Systems. (192.11)

1. Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this rule and of ANSI/NFPA 58 and 59.

2. Each pipeline system subject to this rule that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this rule and of ANSI/NFPA 58 and 59.

3. In the event of a conflict between this rule and ANSI/NFPA 58 and 59, ANSI/NFPA 58 and 59 prevail.

(G) General. (192.13)

1. No person may operate a segment of pipeline that is readied for service after March 12, 1971 unless—

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

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

2. No person may operate a segment of pipeline that is replaced, relocated or otherwise changed after November 12, 1970, unless that replacement, relocation or change has been made in accordance with this rule.

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

4. This section and sections (9), (11)–(16) apply regardless of installation date. The requirements within other sections of this rule apply regardless of the installation date only when specifically stated as such.

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

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

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

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

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

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

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

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

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

B. Buried steel fuel lines that are not cathodically protected may not be converted to a pipeline as defined in paragraph (1)(B)21., such as a service line or main.

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

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

(I) Rules of Regulatory Construction. (192.15)

1. As used in this rule—

A. Includes means including, but not limited to;

B. May means is permitted to or is authorized to;

C. May not means is not permitted to or is not authorized to; and

D. Shall is used in the mandatory and imperative sense.

2. In this rule—

A. Words importing the singular include the plural;

B. Words importing the plural include the singular; and

C. Words importing the masculine gender include the feminine.

(J) Filing of Required Plans, Procedures and Programs. Each operator shall file with designated commission personnel all plans, procedures and programs required by this rule (to include welding and joining procedures, construction standards, corrosion control procedures, replacement programs, operating and maintenance plans, damage prevention programs and emergency plans). In addition, each change must be filed with designated commission personnel within twenty (20) days after the change is made.

(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, 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.

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

(2) Materials.

(A) Scope. (192.51) This section prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

(B) General. (192.53) Materials for pipe and components must be—

1. Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

2. Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact;

3. Qualified in accordance with the applicable requirements of this section; and

4. Only of steel or polyethylene for pipe for the underground construction of pipelines, except that other previously qualified materials may be used for—

A. Repair of existing facilities constructed of the same material; and

B. Fittings, valves or other appurtenances attached to the pipe.

5. Other piping materials may be used with approval of the commission.

(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) 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.

(D) Plastic Pipe. (192.59)

1. New polyethylene pipe is qualified for use under this rule if—

A. It is manufactured in accordance with a listed specification; and

B. It is resistant to chemicals with which contact may be anticipated.

2. Used plastic pipe is qualified for use under this rule if—

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

B. It is resistant to chemicals with which contact may be anticipated;

C. It has been used only in natural gas service;

D. Its dimensions are still within the tolerances of the specification to which it was manufactured; and

E. It is free of visible defects.

3. For the purpose of subparagraphs (2)(D)1.A. and 2.A., where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it—

A. Meets the strength and design criteria required of pipe included in that listed specification; and

B. Is manufactured from plastic compounds which meet the criteria for material required of pipe included in that listed specification.

(E) Marking of Materials. (192.63)

1. Except as provided in paragraph (2)(E)4., each valve, fitting, length of pipe and other component must be marked—

A. As prescribed in the specification or standard to which it was manufactured; however, thermoplastic fittings must be marked in accordance with ASTM D 2513; or

B. To indicate size, material, manufacturer, pressure rating, temperature rating and, as appropriate, type, grade and model.

2. Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

3. If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

4. Paragraph (2)(E)1. does not apply to items manufactured before November 12, 1970, that meet all of the following:

A. The item is identifiable as to type, manufacturer and model; and

B. Specifications or standards giving pressure, temperature and other appropriate criteria for the use of items are readily available.

(F) Transportation of Pipe. (192.65) In a pipeline to be operated at a hoop stress of twenty percent (20%) or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of seventy to one (70:1) or more that is transported by railroad unless—

1. The transportation is performed in accordance with API RP5L1; and

2. In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with section (10) to at least one and one-fourth (1.25) times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least one and one-half (1 1/2) times the maximum allowable operating pressure if it is to be installed in a Class 2, 3 or 4 location. Notwithstanding any shorter time period permitted under section (10), the test pressure must be maintained for at least eight (8) hours.

(3) Pipe Design.

(A) Scope. (192.101) This section prescribes the minimum requirements for the design of pipe.

(B) General. (192.103) Pipe must be designed with sufficient wall thickness, or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation.

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

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

$$P = (2\ St/D) \times F \times E \times T$$

where—

P = Design pressure in pounds per square inch gauge;

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

D = Nominal outside diameter of the pipe in inches;

t = Nominal wall thickness of the pipe in inches. 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)) at any time or is held above six hundred degrees Fahrenheit (600°F) (three hundred and sixteen degrees Celsius (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.

(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") in outside diameter, nor more than one and eleven hundredths (1.11) times the smallest measurement taken on pipe twenty inches (20") or more in outside diameter.

(F) Design Factor (F) for Steel Pipe. (192.111)

1. Except as otherwise provided in paragraphs (3)(F)2.–4., the design factor to be used in the design formula in subsection (3)(C) (192.105) is determined in accordance with the following table:

Class Location	Design Factor (F)
1	0.72
2	0.60
3	0.50
4	0.40

2. A design factor of 0.60 or less must be used in the design formula in subsection (3)(C) (192.105) for steel pipe in Class 1 locations that—

A. Crosses the right-of-way of an unimproved public road without a casing;

B. Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street or a railroad;

C. Is supported by a vehicular, pedestrian, railroad or pipeline bridge; or

D. Is used in a fabricated assembly (including separators, mainline valve assemblies, cross-connections and river crossing headers) or is used within five (5) pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

3. For Class 2 locations, a design factor of 0.50 or less must be used in the design formula in subsection (3)(C) (192.105) for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street or a railroad.

4. For Class 1 and Class 2 locations, a design factor of 0.50 or less must be used in the design formula in subsection (3)(C) (192.105) for—

A. Steel pipe in a compressor station, regulating station or measuring station; and

B. Steel pipe, including a pipe riser, on a platform located in inland navigable waters.

(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:

Specification	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	0.80
Other	Pipe 4 inches 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	Temperature Derating Factor (T)
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	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:

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

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

where

P = Design pressure, 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);

t = Specified wall thickness, mm (in);

D = Specified outside diameter, mm (in); 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) for plastic pipe used in—

A. Distribution systems; or

B. Class 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), or –40°C (–40°F) if all pipe and pipeline components whose operating temperature will be below –29°C (–20°F) 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), it may be used at temperatures up to 38°C (100°F).

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

(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 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)	Nominal O.D. (inch)	Wall Thickness Nominal	(inch) Tolerance
1/2	.625	.040	.0035
5/8	.750	.042	.0035
3/4	.875	.045	.004
1	1.125	.050	.004
1 1/4	1.375	.055	.0045
1 1/2	1.625	.060	.0045

3. Copper pipe used in mains and services lines may not be used at pressures in excess of one hundred (100) psig.

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 of gas.

(4) Design of Pipeline Components.

(A) Scope. (192.141) This section prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

(B) General Requirements. (192.143) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(C) Qualifying Metallic Components. (192.144) Notwithstanding any requirement of this section which incorporates by reference an edition of a document listed in Appendix A, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this rule if—

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

2. The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in Appendix A:

A. Pressure testing;

B. Materials; and

C. Pressure and temperature ratings.

(D) Valves. (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 1/2) 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 1/2) 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; and

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

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

(E) Flanges and Flange Accessories. (192.147)

1. Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI 6.5, MSS SP-44 or the equivalent.

2. Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

3. Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 and be cast integrally with the pipe, valve or fitting.

(F) Standard Fittings. (192.149)

1. The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this rule or their equivalent.

2. Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

(G) Tapping. (192.151)

1. Each mechanical fitting used to make a hot tap must be designed 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 1/4") tap may be made in a four-inch (4") 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") 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 1, 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 or more, or is more than three inches (3") nominal diameter.

(I) Welded Branch Connections. (192.155) Each welded branch connection made to pipe in the form of a single connection or in a header or manifold, as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening and any external loadings due to thermal movement, weight and vibration.

(J) Extruded Outlets. (192.157) Each extruded outlet must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

(K) Flexibility. (192.159) Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints or undesirable forces or moments at points of connection to equipment or at anchorage or guide points.

(L) Supports and Anchors. (192.161)

1. Each pipeline and its associated equipment must have enough anchors or supports to—

A. Prevent undue strain on connected equipment;

B. Resist longitudinal forces caused by a bend or offset in the pipe; and

C. Prevent or damp out excessive vibration.

2. Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.

3. Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows:

A. Free expansion and contraction of the pipeline between supports or anchors may not be restricted;

B. Provision must be made for the service conditions involved; and

C. Movement of the pipeline may not cause disengagement of the support equipment.

4. Each support on an exposed pipeline operated at a stress level of fifty percent (50%) or more of SMYS must comply with the following:

A. A structural support may not be welded directly to the pipe;

B. The support must be provided by a member that completely encircles the pipe; and

C. If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.

5. Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement or it must have an anchor that will limit the movement of the pipeline.

6. Each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

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

1. Location of compressor building. Except for a compressor building on a platform located 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") 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 an 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') 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.

(N) Compressor Stations—Liquid Removal. (192.165)

1. Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of liquids in quantities that could cause damage.

2. Each liquid separator used to remove entrained liquids at a compressor station must—

A. Have a manually operable means of removing these liquids;

B. Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device or a high liquid level alarm; and

C. Be manufactured in accordance with section VIII of the *ASME Boiler and Pressure Vessel Code*, except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4 or less.

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

1. Except for unattended field compressor stations of one thousand (1000) horsepower 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 blowdown 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') 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.

(P) Compressor Stations—Pressure Limiting Devices. (192.169)

1. Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than ten percent (10%).

2. Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

(Q) Compressor Stations—Additional Safety Equipment. (192.171)

1. Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities, their operation may not be affected by the emergency shutdown system.

2. Each compressor station prime mover other than an electrical induction or synchronous motor must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.

3. Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

4. Each compressor station gas engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.

5. Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

(R) Compressor Stations—Ventilation. (192.173) Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits or other enclosed places.

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

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

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

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

where

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

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

P = Maximum allowable operating pressure, psig; 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)
Less than 1000 psig	25
1000 psig or more	100

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 1/2) miles of a valve;

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

C. Each point on the pipeline in a Class 2 location must be within seven and one-half (7 1/2) miles of a valve; and

D. Each point on the pipeline in a Class 1 location must be within ten (10) miles 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.

(V) Distribution Line Valves. (192.181)

1. Each high pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains and the local physical conditions, but it must at least provide zones of isolation sized so that the operator could relight the lost customer services within a period of eight (8) hours after restoration of system pressure.

2. Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping and on the outlet piping at a sufficient distance from the regulator station to permit the operation of the valve during an emergency that might preclude access to the station. An outlet valve on regulator stations will not be required on single-feed distribution systems when the outlet piping size is less than or equal to two inches (2") in nominal diameter.

3. Each valve on a main installed for operating or emergency purposes must comply with the following:

A. The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency;

B. The operating stem or mechanism must be readily accessible; and

C. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.

(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"), 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.

(X) Vaults—Accessibility. (192.185) Each vault must be located in an accessible location and, so far as practical, away from—

1. Street intersections or points where traffic is heavy or dense;

2. Points of minimum elevation, catch basins or places where the access cover will be in the course of surface waters; and

3. Water, electric, steam or other facilities.

(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—

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") 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 but less than two hundred (200) cubic feet—

A. If the vault or pit is sealed, each opening must have a 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.

(Z) Vaults—Drainage and Waterproofing. (192.189)

1. Each vault must be designed so as to minimize the entrance of water.

2. A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

3. All electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the *National Electrical Code*, ANSI/NFPA 70.

(AA) Design Pressure of Plastic Fittings. (192.191) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513.

(BB) Valve Installation in Plastic Pipe. (192.193) Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

(CC) Protection Against Accidental Overpressuring. (192.195)

1. General requirements. Except as provided in subsection (4)(DD) (192.197), each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded, as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of subsections (4)(EE) and (FF). (192.199 and 192.201)

2. Additional requirements for distributions systems. Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

A. Have pressure regulation devices capable of meeting the pressure, load and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

B. Be designed so as to prevent accidental overpressuring.

(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) psig. 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) psig 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) psig 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) psig. 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.

(EE) Requirements for Design of Pressure Relief and Limiting Devices. (192.199) Except for rupture discs, each pressure relief or pressure limiting device must—

1. Be constructed of materials so that the operation of the device will not be impaired by corrosion;

2. Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;

3. Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate and can be tested for leakage when in the closed position;

4. Have support made of noncombustible material;

5. Have discharge stacks, vents or outlet ports designed to prevent accumulation of water, ice or snow, located where gas can be discharged into the atmosphere without undue hazard;

6. Be designed and installed so that the size of the openings, pipe and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;

7. Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident, for instance, an explosion in a vault or damage by a vehicle, from affecting the operation of both the overpressure protective device and the district regulator;

8. Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized access to or operation of the following stop valves regardless of installation date:

A. Any valve that will make the pressure relief valve or pressure limiting device inoperative;

B. Valves that would bypass the regulator or relief devices; and

C. Shut-off valves in control lines that, if operated, would cause the regulator or overpressure protection device to be inoperative;

9. Be designed and installed so that adequate overpressure protection is provided for all town border stations and district regulator stations regardless of installation date;

10. Where a monitor regulator is used for overpressure protection, be designed and installed to include an internal or separate device or method that indicates a failure of the operating regulator regardless of installation date. The operating regulator must be monitored at least monthly for regulator stations for detection of a failure; and

11. Where regulators in series or working monitors are used for overpressure protection, be designed and installed to include an internal or separate device or method that indicates a failure of each regulator regardless of installation date. Each regulator must be monitored at least monthly for regulator stations for detection of a failure. When the operator chooses to use a pressure gauge as the separate device to comply with paragraph (4)(EE)10. or 11., the pressure gauge must have the capability to record the high pressure, such as a recording chart or "tattle-tale" needle (a standard sight gauge is not adequate for this purpose).

(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 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) psig 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) psig or more, but less than sixty (60) psig, the pressure may not exceed the maximum allowable operating pressure plus six (6) psig; or

(III) If the maximum allowable operating pressure is less than twelve (12) psig, 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);

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.

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

1. Except as provided in paragraphs (4)(HH)2. and 3., each new or replacement segment of a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices. For the purposes of this subsection, replacement segment means the actual replaced line pipe, valve, fitting, or other line component.

2. This subsection does not apply to—

A. Manifolds;

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

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

D. Cross-overs;

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

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

G. Other piping that, under section 190.9 of 49 CFR part 190, the administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

3. An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (4)(HH)1., if the operator determines and documents why an impracticability prohibits compliance with paragraph (4)(HH)1. Within thirty (30) days of discovering the emergency or construction problem the operator must petition, under section 190.9 of 49 CFR part 190, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within one (1) year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

(5) Welding of Steel in Pipelines.

(A) Scope. (192.221)

1. This section prescribes minimum requirements for welding steel materials in pipelines.

2. This section does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

(B) General. (192.223)

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

2. Welding must be performed by welders who are qualified under subsections (5)(D) and (E) (192.227 and 192.229) for the welding procedure to be used.

(C) Qualification of Welding Procedures. (192.225)

1. Each welding procedure must be qualified under section IX of the *ASME Boiler and Pressure Vessel Code* or section 2 of API Standard 1104, whichever is appropriate to the function of the weld, except that a welding procedure qualified under an earlier edition previously listed in Appendix A to 49 CFR Part 192 may continue to be used but may not be requalified under the earlier edition.

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

(D) Qualification of Welders. (192.227)

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

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

(E) Limitations on Welders. (192.229)

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

2. No welder may weld with a particular welding process unless, within the preceding six (6) calendar months, s/he has 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") or smaller in diameter, two (2) sample welds tested and found acceptable in accordance with the test in subsection III. of Appendix C to this rule.

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

(G) Miter Joints. (192.233)

1. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of thirty percent (30%) or more of SMYS may not deflect the pipe more than three degrees (3°).

2. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than thirty percent (30%), but more than ten percent (10%), of SMYS may not deflect the pipe more than twelve and one-half degrees (12 1/2°) and must be a distance equal to one (1) pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

3. A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of ten percent (10%) or less of SMYS may not deflect the pipe more than ninety degrees (90°).

(H) Preparation for Welding. (192.235) Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

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

1. Visual inspection of welding must be conducted to insure 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"); 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.

(J) Nondestructive Testing. (192.243)

1. Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate the defects that may affect the integrity of the weld.

2. Nondestructive testing of welds must be performed—

A. In accordance with written procedures; and

B. By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.

3. Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under paragraph (5)(I)3. (192.241[c]).

4. When nondestructive testing is required under paragraph (5)(I)2. (192.241[b]), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:

A. In Class 1 locations, at least ten percent (10%);

B. In Class 2 locations, at least fifteen percent (15%);

C. In Class 3 and Class 4 locations, at crossings of major or navigable rivers and within railroad or public highway rights-of-way, including tunnels, bridges and overhead road crossings, one hundred percent (100%) unless impracticable, in which case at least ninety percent (90%). Nondestructive testing must be impracticable for each girth weld not tested; and

D. At pipeline tie-ins, including tie-ins of replacement sections, one hundred percent (100%).

5. Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when that testing is required under paragraph (5)(I)2. (192.241[b]).

6. When nondestructive testing is required under paragraph (5)(I)2. (192.241[b]), each operator must retain, for the life of the pipeline, a record showing, by milepost, engineering station or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected and the disposition of the rejects.

(K) Repair or Removal of Defects. (192.245)

1. Each weld that is unacceptable under paragraph (5)(I)3. (192.241[c]) must be removed or repaired. A weld must be removed if it has a crack that is more than eight percent (8%) of the weld length.

2. Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

3. Repair of a crack or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under subsection (5)(C) (192.225). Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

(6) Joining of Materials Other Than by Welding.

(A) Scope. (192.271)

1. This section prescribes minimum requirements for joining materials in pipelines, other than by welding.

2. This section does not apply to joining during the manufacture of pipe or pipeline components.

(B) General. (192.273)

1. The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

2. Each joint must be made in accordance with written procedures that have been proved by test or experience to produce strong gastight joints.

3. Each joint must be inspected to ensure compliance with this section.

(C) Cast Iron Pipe. (192.275)

1. Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.

2. Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.

3. Cast iron pipe may not be joined by threaded joints.

4. Cast iron pipe may not be joined by brazing.

(D) Ductile Iron Pipe. (192.277)

1. Ductile iron pipe may not be joined by threaded joints.

2. Ductile iron pipe may not be joined by brazing.

(E) Copper Pipe. (192.279) Copper pipe may not be threaded, except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

(F) Plastic Pipe. (192.281)

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

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

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

B. The solvent cement must conform to ASTM Designation D2513; and

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

3. Heat-fusion joints. Each heat-fusion joint on plastic pipe must comply with the following:

A. A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together and holds the pipe in proper alignment while the plastic hardens;

B. A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature;

C. An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of (6)(G)1.A.(III), to be at least equivalent to those of the fittings manufacturer; and

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

4. Adhesive joints. Each adhesive joint on plastic pipe must comply with the following:

A. The adhesive must conform to ASTM Designation D2517; and

B. The materials and adhesive must be compatible with each other.

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

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

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

(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), 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") per minute, plus or minus twenty-five percent (25%);

D. Pipe specimens less than one hundred and two millimeters (102 mm) (4") 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") 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) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five (5) test results or the manufacturer's rating, whichever is lower, must be used in the design calculations for stress;

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

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

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

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

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

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

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

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

2. The specimen joint must be—

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

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

(I) Tested under any one (1) of the test methods listed under paragraphs (6)(G)1. (192.283[a]) applicable to the type of joint and material being tested;

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

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

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

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

3. A person must be requalified under an applicable procedure if during any twelve (12)-month period that person—

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

B. Has three (3) joints or three percent (3%) of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under subsection (10)(G) (192.513).

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

(I) Plastic Pipe—Inspection of Joints. (192.287) No person may carry out the inspection of joints in plastic pipes required by paragraphs (6)(B)3. and (6)(H)2. (192.273[c] and 192.285[b]) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

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

(A) Scope. (192.301) This section prescribes minimum requirements for constructing transmission lines and mains.

(B) Compliance With Specifications or Standards. (192.303) Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this rule.

(C) Inspection—General. (192.305) Each transmission line or main must be inspected to ensure that it is constructed in accordance with this rule.

(D) Inspection of Materials. (192.307) Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

(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:

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 a 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") in pipe twelve and three-quarters inches (12 3/4") 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 (12 3/4") 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.

(F) Repair of Plastic Pipe During Construction. (192.311) Each pipe segment containing imperfection or damage that would impair the serviceability of plastic pipe must be removed. For repair of plastic pipe other than during construction, see subsection (13)(AA).

(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") 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") or more in diameter unless the arc length, as measured along the crotch, is at least one inch (1").

(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") or larger in diameter, the bend may not have a deflection of more than one and one-half degrees (1 1/2°) 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.

(I) Protection From Hazards. (192.317)

1. The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides or other hazards that may cause the pipeline to move or to sustain abnormal loads.

2. Each aboveground transmission line or main, not located in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

3. Pipelines, including pipe risers, on each platform located in inland navigable waters must be protected from accidental damage by vessels.

(J) Installation of Pipe in a Ditch. (192.319)

1. When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of twenty percent (20%) or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

2. When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that—

A. Provides firm support under the pipe; and

B. Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(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"), except that pipe with an outside diameter of 0.875 inches (0.875") or less may have a minimum wall thickness of 0.062 inches (0.062").

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.

(L) Casing. (192.323) Each casing used on a transmission line or main under a railroad or highway must comply with the following:

1. The casing must be designed to withstand the superimposed loads;

2. If there is a possibility of water entering the casing, the ends must be sealed;

3. If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than seventy-two percent (72%) of SMYS; and

4. If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

(M) Underground Clearance. (192.325)

1. Each transmission line must be installed with at least twelve inches (12") 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	
Class 1 locations	30	18
Class 2, 3 and 4 locations	36	24
Drainage ditches of public roads and railroad crossings	36	24

2. Except as provided in paragraphs (7)(N)3. and 4., each buried main must be installed with at least twenty-four inches (24") 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") of cover if the law of the state or municipality—

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

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") in soil or twenty-four inches (24") in consolidated rock between the top of the pipe and the natural bottom.

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

(A) Scope, Compliance with Specifications or Standards, and Inspections. (192.351) This section prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves and service line connections to mains. Service lines must be constructed in accordance with comprehensive written specifications or standards that are consistent with this rule. Service lines must be inspected to ensure they are constructed in accordance with this rule. Each service line component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

(B) Service Lines and Yard Lines.

1. All service line installations and residential/small commercial yard line replacements made after December 15, 1989, must be installed, owned, operated and maintained by the operator regardless of meter location. Installations of customer-owned service lines and residential/small commercial yard lines, as defined in (1)(B) (192.3), will not be permitted. If the customer meter is not located within five feet (5') of the building wall, the service line to the customer's nearest building shall be installed, owned, operated and maintained by the operator. Installation and maintenance may be performed by representatives approved by the operator and the operator must assure that the work performed by approved representatives is in compliance with the requirements of this rule.

2. Yard lines for large commercial/industrial customers may be installed or replaced, owned and maintained, except for leak surveys, by the customer, provided the new yard line is cathodically protected, coated steel or polyethylene pipe and the operator's installation standards are met.

(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') 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.

(D) Customer Meters and Regulators—Protection From Damage. (192.355)

1. Protection from vacuum or back pressure. If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.

2. Service regulator vents and relief vents. Service regulator vents and relief vents must terminate outdoors and the outdoor terminal must—

A. Be rain and insect resistant;

B. Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and

C. Be protected from damage caused by submergence in areas where flooding may occur.

3. Pits and vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated must be able to support that traffic.

(E) Customer Meters and Regulators—Installation. (192.357)

1. Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

2. When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this rule.

3. Connections made of lead and other easily damaged material may not be used in the installation of meters or regulators.

4. Each regulator equipped with a vent must be vented to the atmosphere outside the 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) psig.

3. A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than fifty percent (50%) 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") of cover in private property and at least eighteen inches (18") 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") 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.

(H) Service Lines—Valve Requirements. (192.363)

1. Each service line must have a service line valve that meets the applicable requirements of sections (2) and (4) of this rule. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service line valve.

2. A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.

3. Each service line valve on a high-pressure service line, installed aboveground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

(I) Service Lines—Location of Valves. (192.365)

1. Relation to regulator or meter. Each service line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.

2. Outside valves. Each service line must have a shut-off valve in a readily accessible location that is outside of the building.

3. Underground valves. Each underground service line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

(J) Service Lines—General Requirements for Connections to Main Piping. (192.367)

1. Location. Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

2. Compression-type connection to main. Each compression-type service line to main connection must—

A. Be designed and installed to effectively sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

B. If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

(K) Service Lines—Connections to Cast Iron or Ductile Iron Mains. (192.369)

1. Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of subsection (6)(B). (192.273)

2. If a threaded tap is being inserted, the requirements of paragraphs (4)(G)2. and 3. (192.151[b] and [c]) must also be met.

(L) Service Lines—Steel. (192.371) Each steel service line to be operated at less than one hundred (100) psig must be constructed of pipe designed for a minimum of one hundred (100) psig.

(M) Service Lines—Plastic. (192.375)

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

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

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

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

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

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

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

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

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

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

7. 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.

(N) New Service Lines Not in Use. (192.379) Each service line that is not placed in service upon completion of installation must comply with one (1) of the following until the customer is supplied with gas:

1. 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;

2. 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

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

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

1. Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than ten (10) psig 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) psig:

(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; 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; 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.

(9) Requirements for Corrosion Control.

(A) Scope. (192.451) This section prescribes minimum requirements for the protection of metallic pipelines from external, internal and atmospheric corrosion.

(B) Applicability to Converted Pipelines. (192.452) Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this rule in accordance with subsection (1)(H) (192.14) must have a cathodic protection system designed to protect the pipeline in its entirety in accordance with subsection (9)(H) (192.463) within one (1) year after the pipeline is readied for service.

(C) General. (192.453) Each operator shall establish written procedures as required by subparagraph (12)(C)2.B. to implement the requirements of this section. Each written procedure, including those for the design, installation, operation and maintenance of cathodic protection systems, shall be carried out by, or under the direction of, a person qualified by experience and training in pipeline corrosion control methods.

(D) External Corrosion Control—Buried or Submerged Pipelines Installed After July 31, 1971. (192.455)

1. Except as provided in paragraphs (9)(D)2. and 5., each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

A. It must have an external protective coating meeting the requirements of subsection (9)(G) (192.461); and

B. It must have a cathodic protection system designed to protect the pipeline in accordance with this section, installed and placed in operation within one (1) year after completion of construction.

2. An operator need not comply with paragraph (9)(D)1., if the operator can demonstrate by tests, investigation or experience that—

A. For a copper pipeline, a corrosive environment does not exist; or

B. For a temporary pipeline with an operating period of service not to exceed five (5) years beyond installation, corrosion during the five (5)-year period of service of the pipeline will not be detrimental to public safety.

3. Notwithstanding the provisions of paragraph (9)(D)2., if a pipeline is externally coated, it must be cathodically protected in accordance with subparagraph (9)(D)1.B.

4. Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of eight (8), unless tests or experience indicate its suitability in the particular environment involved.

5. This subsection does not apply to electrically isolated, metal alloy fittings in plastic pipelines, if—

A. For the size fitting to be used, an operator can show by test, investigation or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

B. The fitting is designed to prevent leaking caused by localized corrosion pitting.

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

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

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

A. Bare or ineffectively coated transmission lines;

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

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

D. Bare or coated service lines, except that steel service lines must be replaced as required by subsection (15)(C). The operator shall determine the areas of active corrosion by electrical survey. Where electrical survey is impractical, the areas of active corrosion shall be determined by the study of corrosion and leak history records, and by instrument leak detection survey. After this initial evaluation for areas of active corrosion, each operator must conduct reevaluations as required by paragraph (9)(I)5.

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

(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, remedial action must be taken to the extent required by subsection (9)(R) (192.483) and the applicable paragraphs of subsections (9)(S), (T) or (U). (192.485, 192.487 or 192.489)

(G) External Corrosion Control—Protective Coating. (192.461)

1. Each external protective coating applied for the purpose of external corrosion control must—

A. Be applied on a properly prepared surface;

B. Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

C. Be sufficiently ductile to resist cracking;

D. Have sufficient strength to resist damage due to handling and soil stress; and

E. Have properties compatible with any supplemental cathodic protection.

2. Each external protective coating must also have low moisture absorption and high electrical resistance.

3. Each external protective coating must be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired.

4. Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

5. If coated pipe is installed by boring, driving or other similar method, precautions must be taken to minimize damage to the coating during installation.

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

1. Each cathodic protection system required by this section must provide a level of cathodic protection that complies with one (1) or more of the applicable criteria contained in Appendix D.

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

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

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

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

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

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

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

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

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

5. After the initial evaluation required by paragraph (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.

(J) External Corrosion Control—Electrical Isolation. (192.467)

1. Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

2. One (1) or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

3. Except for unprotected copper inserted in a ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

4. Inspection and electrical tests must be made to assure that electrical isolation is adequate.

5. An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

6. Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

(K) External Corrosion Control—Test Stations. (192.469) Each pipeline under cathodic protection required by this section must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

(L) External Corrosion Control—Test Leads. (192.471)

1. Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.

2. Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.

3. Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

(M) External Corrosion Control—Interference Currents. (192.473)

1. Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of these currents.

2. Each impressed current type cathodic protection system or galvanic anode system

must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures.

(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 (four (4) parts per million) may not be stored in pipe-type or bottle-type holders.

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

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

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

2. Pipelines installed before August 1, 1971. Each operator having an aboveground pipeline or portion of a pipeline installed before August 1, 1971, that is exposed to the atmosphere, shall—

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

B. If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of subsections (9)(S), (T) or (U) (192.485, 192.487 or 192.489); and

C. Clean and either coat or jacket the areas of atmospheric corrosion on the pipeline with a material suitable for the prevention of atmospheric corrosion.

3. For the purposes of this section, atmospheric corrosion means corrosion that has resulted in pitting of the base metal.

(Q) Atmospheric Corrosion Control—Monitoring. (192.481) After meeting the requirements of paragraphs (9)(P)1. and 2. (192.479[a] and [b]), each operator, at intervals not exceeding three (3) years, shall reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion. When remedial action is necessary, corrective actions must be completed within twelve (12) months unless otherwise approved by designated commission personnel.

(R) Remedial Measures—General. (192.483)

1. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of subsection (9)(G). (192.461)

2. Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected and monitored in accordance with this section.

3. Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected and monitored in accordance with this section.

(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. 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. 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.

(U) Remedial Measures—Cast Iron and Ductile Iron Pipelines. (192.489)

1. General graphitization. Each segment of cast iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or any leakage might result must be replaced.

2. Localized graphitization. Each segment of cast iron or ductile iron pipe on which localized graphitization is found to a degree where any leakage might result must be replaced or repaired, or sealed by internal sealing methods adequate to prevent or arrest any leakage.

(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 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.

(A) Scope. (192.501) This section prescribes minimum leak-test and strength-test requirements for pipelines.

(B) General Requirements. (192.503)

1. No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until—

A. It has been tested in accordance with this section and subsection (12)(M) (192.619) to substantiate the maximum allowable operating pressure; and

B. Each potentially hazardous leak has been located and eliminated.

2. The test medium must be liquid, air, natural gas or inert gas that is—

A. Compatible with the material of which the pipeline is constructed;

B. Relatively free of sedimentary materials; and

C. Except for natural gas, nonflammable.

3. Except as provided in paragraph (10)(C)1. (192.505[a]), if air, natural gas or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class Location	Maximum Hoop Stress Allowed as Percentage of SMYS	
	Natural Gas	Air or Inert Gas
1	80	80
2	30	75
3	30	50
4	30	40

4. Each connection used to tie-in a test segment of pipeline is excepted from the specific test requirements of this section, but it must be leak tested at not less than its operating pressure.

(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') 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') of such a building, but in no event may the test section be less than six hundred feet (600') unless the length of the newly installed or relocated pipe is less than six hundred feet (600'). 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) psig. (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) psig 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) psig 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) psig. (192.509) Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below one hundred (100) psig must be leak tested in accordance with the following:

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

2. Each main that is to be operated at less than one (1) psig must be tested to at least ten (10) psig, each main to be operated at or above one (1) psig through ninety (90) psig must be tested to at least ninety (90) psig, and each main that is to be operated between ninety (90) psig and one hundred (100) psig must be tested to at least one hundred (100) psig.

(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) psig but not more than forty (40) psig must be given a leak test at a pressure of not less than fifty (50) psig.

3. Each segment of a service line (other than plastic) intended to be operated at pressures of more than forty (40) psig through ninety (90) psig must be tested to at least

ninety (90) psig; if the service line is to be operated between ninety (90) psig and one hundred (100) psig, it must be tested to at least one hundred (100) psig; and if the service line may be operated at one hundred (100) psig 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) psig, 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), 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 ensure 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 that the test medium is disposed of in a manner that will minimize damage to the environment.

(I) Records. (192.517)

1. For mains, each operator shall make and retain for the useful life of the pipeline, a record of each test performed under subsections (10)(C)—(E) and (G). (192.505, 192.507, 192.509 and 192.513) Where applicable to the test performed, the record must contain at least the following information, except as noted in subparagraph (10)(I)1.B.

A. The operator's name, the name of the operator's employee responsible for making the test and the name of any test company used;

B. Test medium used, except for tests performed pursuant to subsections (10)(E) and (G);

C. Test pressure;

D. Test duration;

E. Pressure recording charts or other record of pressure readings;

F. Elevation variations, whenever significant for the particular test;

G. Leaks and failures noted and their disposition;

H. Test date; and

I. Description of facilities being tested.

2. For service lines, each operator shall make and retain for the useful life of the pipeline, a record of each test performed under subsections (10)(F) and (G) (192.511 and 192.513) Where applicable to the test performed, the record must contain the test pressure, leaks and failures noted and their disposition and the date.

(J) Test Requirements for Customer-Owned Fuel Lines.

1. At the initial time an operator physically turns on the flow of gas to new fuel line installations—

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

B. A visual inspection of the exposed, accessible customer gas piping, interior and exterior, and all connected equipment shall be conducted to determine that the requirements of any applicable industry codes, standards or procedures adopted by the operator to assure safe service are met; and

C. The requirements of any applicable local (city, county, etc.) codes must be met.

2. The temperature of thermoplastic material must not be more than one hundred degrees Fahrenheit (100°F) during the test.

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

(11) Uprating.

(A) Scope. (192.551) This section prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

(B) General Requirements. (192.553)

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

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

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

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

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

4. Limitation on increase in maximum allowable operating pressure. Except as provided in (11)(C)3. (192.555[c]), a new maximum allowable operating pressure established under this section may not exceed the maximum that would be allowed under this rule for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula in subsection (3)(C) is unknown, the MAOP may be increased as provided in subparagraph (12)(M)1.A.

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

(C) Uprating to a Pressure That Will Produce a Hoop Stress of Thirty Percent (30%) or More of SMYS in Steel Pipelines. (192.555)

1. Unless the requirements of this subsection have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of thirty percent (30%) or more of SMYS and

that is above the 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 and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this rule; and

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

3. After complying with paragraph (11)(C)2., an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under subsection (12)(M) (192.619), using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

4. After complying with paragraph (11)(C)2., an operator that does not qualify under paragraph (11)(C)3. may increase the previously established maximum allowable operating pressure if at least one (1) of the following requirements is met:

A. The segment of pipeline is successfully tested in accordance with the requirements of this rule for a new line of the same material in the same location; or

B. An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if—

(I) It is impractical to test it in accordance with the requirements of this rule;

(II) The new maximum operating pressure does not exceed eighty percent (80%) of that allowed for a new line of the same design in the same location; and

(III) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this rule.

5. Where a segment of pipeline is uprated in accordance with paragraph (11)(C)3. or subparagraph (11)(C)4.B., the increase in pressure must be made in increments that are equal to—

A. Ten percent (10%) of the pressure before the uprating; or

B. Twenty-five percent (25%) of the total pressure increase, whichever produces the fewer number of increments.

(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) psig 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)
Cast Iron Pipe

Pipe Size (inches)	Pit Cast Pipe	Centrifugally Cast Pipe	Ductile Iron Pipe
3 to 8	0.075	0.065	0.065
10 to 12	0.08	0.07	0.07
14 to 24	0.08	0.08	0.075
30 to 42	0.09	0.09	0.075
48	0.09	0.09	0.08
54 to 60	0.09	—	—

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 and a modulus of rupture of thirty-one thousand (31,000) psi.

(12) Operations.

(A) Scope. (192.601) This section prescribes minimum requirements for the operation of pipeline facilities.

(B) General Provisions. (192.603)

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

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

3. Each operator shall be responsible for ensuring that all work completed by its consultants and contractors complies with this rule.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

M. Testing and inspecting of customer-owned gas piping and equipment.

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

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

(I) Unintended closure of valves or shutdowns;

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

(III) Loss of communications;

(IV) Operation of any safety device; and

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

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

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

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

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

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

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

(D) Personnel Qualification.

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 required 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.

2. Personnel to whom this subsection applies must be trained to—

A. Perform the requirements of this rule that relate to their assigned functions;

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;

C. Utilize instruments and equipment that relate to their assigned functions in accordance with manufacturer's instructions;

D. Know the characteristics and hazards of the gas transported, including flammability range, and toxicity, olfactory 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, 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 subsection 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.

6. Each operator shall require and verify that supervisors maintain a thorough knowledge of that portion of the procedures required by this subsection for which they are responsible to ensure compliance.

7. Each operator shall maintain records that demonstrate that personnel have been qualified as required by paragraph (12)(D)1. and attended training as required by paragraph (12)(D)3. The records must be maintained during that individual's employment and for at least three (3) years thereafter.

(E) (Reserved) (192.607)

(F) Change in Class Location—Required Study. (192.609) Whenever an increase in population density indicates a change in class locations for a segment of an existing steel pipeline operating at a hoop stress that is more than forty percent (40%) of SMYS or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine—

1. The present class location for the segment involved;

2. The design, construction and testing procedures followed in the original construction and a comparison for these procedures with those required for the present class location by the applicable provisions of this rule;

3. The physical condition of the segment to the extent it can be ascertained from available records;

4. The operating and maintenance history of the segment;

5. The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

6. The actual area affected by the population density increase and physical barriers or other factors which may limit further expansion of the more densely populated area.

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

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

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

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

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

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

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

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

6. Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under subsection (12)(F) (192.609) must be completed within eighteen (18) months of the change in class location. Pressure reduction under paragraph (12)(G)1. or 2. within the eighteen (18)-month period does not preclude establishing a maximum allowable operating pressure under paragraph (12)(G)3., at a later date.

(H) Continuing Surveillance. (192.613)

1. Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements and other unusual operating and maintenance conditions.

2. If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out

the segment involved or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with paragraphs (12)(M)1. and 2. (192.619[a] and [b])

(I) Damage Prevention Program. (192.614)

1. Except for pipelines listed in paragraph (12)(I)5., 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 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 this participation does not relieve the operator of responsibility for compliance with this subsection.

2. 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., then such updated listing shall be provided to the one-call notification center prior to December 1 of each calendar year. This list should at least include, but not be limited to, the following:

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

(II) Telephone company;

(III) Electric utilities and co-ops;

(IV) Water and sewer utilities;

(V) City governments;

(VI) County governments;

(VII) Special road districts;

(VIII) Special water and sewer districts; and

(IX) Highway department district(s);

B. Provide for at least a semiannual general notification of the public in the vicinity of the pipeline. Provide for actual notification of the persons identified in subparagraph (12)(I)2.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. 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., 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.;

(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), 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): 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. as follows:

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

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

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

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

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

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

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

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

3. Each notification identified in subparagraph (12)(I)2.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. 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. 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.

(J) Emergency Plans. (192.615)

1. Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

A. Receiving, identifying and classifying notices of events which require immediate response by the operator;

B. Establishing and maintaining adequate means of communication with appropriate fire, police and other public officials;

C. Responding promptly and effectively to a notice of each type of emergency, including the following:

(I) Gas detected inside or near a building;

(II) Fire located near or directly involving a pipeline facility;

(III) Explosion occurring near or directly involving a pipeline facility; and

(IV) Natural disaster;

D. Making available personnel, equipment, tools and materials, as needed at the scene of an emergency;

E. Taking actions directed toward protecting people first and then property;

F. Causing an emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property;

G. Making safe any actual or potential hazard to life or property;

H. Notifying appropriate fire, police and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency;

I. Safely restoring any service outage; and

J. Beginning action under subsection (12)(L) (192.617), if applicable, as soon after the end of the emergency as possible.

2. Each operator shall—

A. Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (12)(J)1. as necessary for compliance with those procedures;

B. Train the appropriate operating personnel and conduct an annual review to assure that they are knowledgeable of the emergency procedures and verify that the training is effective; and

C. Review employee activities to determine whether the procedures were effectively followed in each emergency.

3. Each operator shall establish and maintain liaison with appropriate fire, police and other public officials to—

A. Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

B. Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

C. Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

D. Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

(K) Public Education. (192.616) Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area. The program must provide for notification of the intended groups on the following schedule:

1. Appropriate government organizations and persons engaged in excavation related activities must be notified at least annually;

2. The public must be notified at least semiannually; and

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

(L) Investigation of Failures. (192.617) Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

(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 3/4") or less in outside diameter and is not tested to yield under this paragraph, two hundred (200) psig;

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); and

(II) For steel pipe operated at one hundred (100) psig 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 section 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) psig, for a segment of a distribution system otherwise designated to operate at over sixty (60) psig, 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) psig 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)

(O) Maximum and Minimum Allowable Operating Pressure—Low-Pressure Distribution Systems. (192.623)

1. No person may operate a low-pressure distribution system at a pressure greater than—

A. A pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas utilization equipment; or

B. An equivalent of fourteen inches (14") water column.

2. No person may operate a low-pressure distribution system at a pressure lower than—

A. The minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas utilization equipment can be assured; or

B. An equivalent of four inches (4") water column.

(P) Odorization of Gas. (192.625)

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

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

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

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

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

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

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

6. Each operator shall conduct, at least monthly, odor intensity tests with an instrument to assure the proper concentration of odorant and odorant intensity in accordance with this subsection. At individually odorized service lines, the odor intensity shall be checked at least once each calendar year at intervals not to exceed fifteen (15) months. Operators of master meter systems may comply with this paragraph by—

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

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

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

(Q) Tapping Pipelines Under Pressure. (192.627) Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

(R) Purging of Pipelines. (192.629)

1. When a pipeline is being purged of air by use of gas, the gas must be released into one (1) end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

2. When a pipeline is being purged of gas by use of air, the air must be released into one (1) end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

(S) Providing Service to Customers.

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

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

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

2. When providing gas service to a new customer or a customer relocated from a different operating district, the operator must provide the customer with the following as

soon as possible, but within seven (7) calendar days, unless the operator can demonstrate that the information would be the same:

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

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

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

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

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

(13) Maintenance.

(A) Scope. (192.701) This section prescribes minimum requirements for maintenance of pipeline facilities.

(B) General. (192.703)

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

2. Each segment of pipeline that becomes unsafe must be replaced, repaired or removed from service.

3. Leaks must be investigated, classified and repaired in accordance with section (14).

(C) Transmission Lines—Patrolling. (192.705)

1. Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity and other factors affecting safety and operation.

2. The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table:

Maximum Interval Between Patrols

Class Location of Line	At Highway and Railroad Crossing Locations	At All Other Locations
1,2	7 1/2 months; but at least twice each calendar year	15 months;but at least once each calendar year
3	4 1/2 months; but at least four times each calendar year	7 1/2 months; but at least twice each calendar year
4	4 1/2 months; but at least four times each calendar year	4 1/2 months; but at least four times each calendar year

3. Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

(D) Transmission Lines—Leakage Surveys. (192.706)

1. Instrument leak detection surveys of a transmission line must be conducted—

A. In Class 3 locations, at intervals not exceeding seven and one-half (7 1/2) months but at least twice each calendar year;

B. In Class 4 locations, at intervals not exceeding four and one-half (4 1/2) months but at least four (4) times each calendar year; and

C. In all other locations, at intervals not exceeding fifteen (15) months but at least once each calendar year.

2. Distribution lines, yard lines and buried fuel lines connected to a transmission line must be leak surveyed in accordance with subsection (13)(M).

(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 aboveground.

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") high with one-quarter inch (1/4") 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.

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]), 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 imperfection or damage that impairs the serviceability of a segment of 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 by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength;

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

C. If the segment is not taken out of service, the operating pressure must be reduced to 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") 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 permanent field repair of a leak on a transmission line must be made as follows:

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

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

(I) Is joined by mechanical couplings; and

(II) Operates at less than forty percent (40%) of SMYS; and

C. If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp or, if the leak is due to a corrosion pit and on pipe of not more than forty thousand (40,000) psi SMYS, the repair may be made by fillet welding 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. Submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

(K) Transmission Lines—Testing of Repairs. (192.719)

1. Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

2. Testing of repairs made by welding. Each repair made by welding in accordance with subsections (13)(H), (I) and (J) (192.713, 192.715 and 192.717) must be examined in accordance with subsection (5)(I). (192.241)

(L) Distribution Systems—Patrolling. (192.721)

1. The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage and the consequent hazards to public safety.

2. Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled—

A. In business districts, at intervals not exceeding four and one-half (4 1/2) months but at least four (4) times each calendar year; and

B. Outside business districts, at intervals not exceeding seven and one-half (7 1/2) months, but at least twice each calendar year.

3. Feeder lines shall be patrolled at intervals not exceeding fifteen (15) months but at least once each calendar year.

(M) Distribution Systems—Leakage Surveys. (192.723)

1. Each operator of a distribution line or system shall conduct periodic instrument leakage surveys in accordance with this subsection.

2. The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions but it must meet the following minimum requirements:

A. An instrument leak detection survey must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, at cracks in pavement and sidewalks and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding fifteen (15) months but at least once each calendar year;

B. Except as provided for in subparagraph (13)(M)2.C., instrument leak detection surveys must be conducted outside of business districts as frequently as necessary, but at intervals not exceeding—

(I) Fifteen (15) months, but at least once each calendar year, for unprotected steel pipelines and unprotected steel yard lines;

(II) Thirty-nine (39) months, but at least once each third calendar year, for all other pipelines and yard lines; and

(III) Thirty-nine (39) months, but at least once each third calendar year, for buried fuel lines operating above low pressure at residential, small commercial and public buildings, and for all buried fuel lines at institutional buildings, such as hospitals and schools. Instrument leak detection surveys of buried fuel lines may be conducted around a portion of the perimeter of the building. This perimeter-type survey shall be conducted along the side of the building nearest the meter location (or the fuel line entrances in the case of multiple buildings) and along the closest adjacent side; and

C. For yard lines and buried fuel lines that are required to be leak surveyed under subparagraph (13)(M)2.B., but are located within high security areas such as prisons, notifications to the customer as described in paragraph (13)(M)3. may be conducted instead of a leak survey.

3. The operator must notify large commercial/industrial customers with buried fuel lines operating above low pressure at one or more buildings, that are not leak surveyed in accordance with part (13)(M)2.B.(III), that maintenance is the customer's responsibility and leak surveys should be conducted. Notification must be provided once each third calendar year, at intervals not exceeding thirty-nine (39) months.

4. Recordkeeping requirements for leak surveys and notifications are contained in subsection (13)(F).

(N) Test Requirements for Reinstating Service Lines and Fuel Lines. (192.725)

1. Except as provided in paragraphs (13)(N)2. and 4., each disconnected service line must be tested in the same manner as a new service line and the associated fuel line must meet the requirements of subsection (12)(S) before being reinstated.

2. Before reconnecting, each service line temporarily disconnected from the transmission line or main for any reason must be tested from the point of disconnection to the service line valve in the same manner as a new service line. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested. If continuous service is not maintained, the requirements in subsection (12)(S) must be met for the associated fuel line.

3. Except for system outages, each fuel line to which service has been discontinued shall have service resumed in accordance with subsection (12)(S). Each fuel line restored after a system outage shall have service resumed in accordance with subparagraph (12)(S)1.A. and the procedures required under subparagraph (12)(J)1.I. (192.615[a][9])

4. Each service line temporarily disconnected from the transmission line or main due to third party damage must be tested from the point of disconnection to the main in the same manner as a new service line, or it may be surveyed from the point of disconnection to the main using a leak detection instrument.

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

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

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

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

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

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

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

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

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

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

(P) Compressor Stations—Inspection and Testing of Relief Devices. (192.731)

1. Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with subsections (13)(R) and (T) (192.739 and 192.743), and must be operated periodically to determine that it opens at the correct set pressure.

2. Any defective or inadequate equipment found must be promptly repaired or replaced.

3. Each remote control shutdown device must be inspected and tested at intervals not exceeding fifteen (15) months but at least once each calendar year to determine that it functions properly.

(Q) Compressor Stations—Storage of Combustible Materials and Gas Detection. (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 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.

(R) Pressure Limiting and Regulating Stations—Inspection and Testing. (192.739) Each pressure limiting station, relief device (except rupture discs) and pressure regulating station and its equipment must be subjected at intervals not exceeding fifteen (15) months but at least once each calendar year to inspections and tests to determine that it is—

1. In good mechanical condition;

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

3. Set to control or relieve at the correct pressures that will prevent downstream pressures from exceeding the allowable pressures under subsections (4)(CC), (12)(M)—(O);

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

5. Properly protected from unauthorized operation of valves in accordance with paragraph (4)(EE)8. (192.199[h]);

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

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

(S) Pressure Limiting and Regulating Stations—Telemetering or Recording Gauges. (192.741)

1. Each distribution system supplied by more than one (1) district pressure regulating station and/or furnishing service to more than one thousand (1000) customers must be

equipped with graphic telemetering, recording pressure gauges, or another device (other than pressure gauges unless they are continuously monitored) to indicate the gas pressure in the district.

2. On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation and other operating conditions.

3. If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

4. All telemetered or recorded pressure data shall be identified, dated and kept on file for a minimum of two (2) years.

(T) Pressure Limiting and Regulating Stations— Testing of Relief Devices. (192.743)

1. If feasible, pressure relief devices (except rupture discs) must be tested in place at intervals not exceeding fifteen (15) months but at least once each calendar year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure which does not exceed the pressure allowed by subsection (4)(FF).

2. If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made at intervals not exceeding fifteen (15) months but at least once each calendar year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works. After the initial calculations, subsequent calculations are not required if the review documents that parameters have not changed in a manner which would cause the capacity to be less than required.

3. If the relieving device is of insufficient capacity to comply with subsection (4)(FF), a new or additional device must be installed to provide the additional capacity required.

(U) Valve Maintenance—Transmission Lines. (192.745) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding fifteen (15) months but at least once each calendar year.

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

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

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

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

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

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

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

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

(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 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.

(X) Prevention of Accidental Ignition. (192.751) Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

1. When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided;

2. Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work; and

3. Warning signs shall be posted, where appropriate.

(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) psig 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) psig and is exposed for any reason must be sealed by a means other than caulking.

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

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

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

B. Impact forces by vehicles;

C. Earth movement;

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

E. Apparent future excavations near the pipeline; or

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

2. If eight inches (8") or less in nominal diameter, then as soon as feasible, this segment of cast iron pipeline, which shall include a minimum of ten feet (10') beyond

the area of affected soil, must be replaced, except as noted in paragraph (13)(Z)4.;

3. If greater than eight inches (8") in nominal diameter, then as soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of subsection (7)(J) (192.319) and paragraph (7)(I)1. (192.317[a]); and

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

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

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

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

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

(AA) Repair of Plastic Pipe. Each leak, imperfection or damage that impairs the serviceability of a plastic pipe must be removed, except that heat fusion patching saddles may be used to repair holes that have been tapped into the main for service installations, and full-encirclement heat fusion couplings may be used to repair and reinforce butt fusion joints. These patching saddles and couplings shall not be used for the repair of any imperfections or third-party damage sustained by the plastic pipe.

(14) Gas Leaks.

(A) Scope. This section prescribes the procedures for the investigation and classification of gas leaks and for scheduling the repair of these 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 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.

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

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

2. Class 2 leak is a leak that does not constitute an immediate hazard to a building or to the general public, but is of a nature requiring action as soon as possible. The leak of this classification must be rechecked every fifteen (15) days, until repaired, to determine that no immediate hazard exists. A Class 2 leak may be properly reclassified to a lower leak classification within fifteen (15) days after the initial investigation. Class 2 leaks due to readings in sanitary sewers, tunnels, or confined areas must be repaired or properly reclassified within fifteen (15) days after the initial investigation. All other Class 2 leaks must be eliminated within forty-five (45) days after the initial investigation, unless it is definitely included and scheduled in a rehabilitation or replacement program to be completed within a period of one (1) year, in which case the leak must be rechecked every fifteen (15) days to determine that no immediate hazard exists. Examples of Class 2 leaks are: a leak

from a transmission line discernible twenty-five feet (25') or more from the line and within one hundred feet (100') of a building; any reading outside a building at the foundation or within five feet (5') of the foundation; any reading greater than fifty percent (50%) gas-in-air located five to fifteen feet (5'–15') from a building; any reading below the lower explosive limit in a tunnel, sanitary sewer or confined area; any reading equal to or above the lower explosive limit in a vault, catch basin or manhole other than a sanitary sewer; or any leak, other than a Class 1 leak, which in the judgment of the supervisor at the scene, is regarded as requiring Class 2 leak priority.

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

4. Class 4 leak is a confined or localized leak which is completely non-hazardous. No further action is required.

(15) Replacement Programs.

(A) Scope. This section prescribes minimum requirements for the establishment of replacement programs for certain pipelines.

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

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

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

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

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

(D) Replacement Program—Cast Iron.

1. Operators who have cast iron transmission lines, feeder lines or mains shall develop a replacement program to be submitted with an explanation to the commission by May 1, 1990, for commission review and approval. This systematic replacement program shall be prioritized to identify and eliminate pipelines in those areas that present the greatest potential for hazard in an expedited manner. These high priority replacement areas would include, but not be limited to:

A. High-pressure cast iron pipelines located beneath pavement which is continuous to building walls;

B. High-pressure cast iron pipelines located near concentrations of the general public such as Class 4 locations, business districts and schools;

C. Small diameter cast iron pipelines;

D. Areas where extensive excavation, blasting or construction activities have occurred in close proximity to cast iron pipelines;

E. Sections of cast iron pipeline that have had sections replaced as a result of requirements in subsection (13)(Z) (192.755);

F. Sections of cast iron pipeline that lie in areas of planned future development projects, such as city, county or state highway construction/relocations, urban renewal, etc.; and

G. Sections of cast iron pipeline that exhibit a history of leakage or graphitization.

2. A long-term, organized replacement program and schedule shall also be established for cast iron pipelines not identified by the operator as being high priority.

3. Operators who have cast iron service lines shall replace them by December 31, 1991.

(E) Replacement/Cathodic Protection Program—Unprotected Steel Transmission Lines, Feeder Lines and Mains. Operators who have unprotected steel transmission lines, feeder lines or mains shall develop a program to be submitted with an explanation to the commission by May 1, 1990, for commission review and approval. This program shall be prioritized to identify and cathodically protect or replace pipelines in those areas that present the greatest potential for hazard in an expedited manner. These high priority areas should include, but not be limited to:

1. High-pressure unprotected steel pipelines located beneath pavement which is continuous to building walls;

2. High-pressure unprotected steel pipelines near concentrations of the general public such as Class 4 locations, business districts and schools;

3. Areas where extensive excavation, blasting or construction activities have occurred in close proximity to unprotected steel pipelines;

4. Sections of unprotected steel pipeline that lie in areas of planned future development projects, such as city, county or state highway construction/relocations, urban renewal, etc.;

5. Sections of unprotected steel pipeline that exhibit a history of leakage or corrosion; and

6. Sections of unprotected steel pipeline subject to stray current.

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

AUTHORITY: sections 386.250 and 386.310, RSMo Supp. 1997 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.*

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

Appendix A—4 CSR 240-40.030
Appendix A—Incorporated by Reference

I. List of organizations and address.

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

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

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

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

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

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

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

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

A. American Gas Association (AGA):

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

B. American Petroleum Institute (API):

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

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

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

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

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

1) ASTM Designation A 53 *Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless* (A 53-95a).

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

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 Plastic* (D 638-95).

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).

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

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

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

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

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

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

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

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

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

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

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

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

1) MSS SP-44 *Steel Pipe Line Flanges* (1991).

F. National Fire Protection Association (NFPA):

1) ANSI/NFPA 30 *Flammable and Combustible Liquids Code* (1993).

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 5L—Steel pipe (1995).

ASTM A 53—Steel pipe (1995a).

ASTM A 106—Steel pipe (1994a).

ASTM A 333/A 333M—Steel pipe (1994).

ASTM A 381—Steel pipe (1993).

ASTM A 671—Steel pipe (1994).

ASTM A 672—Steel pipe (1994).

ASTM A 691—Steel pipe (1993).

ASTM D 2513—Thermoplastic pipe and tubing (1995c).

ASTM D 2517—Thermosetting plastic pipe and tubing (1994).

II. Steel pipe of unknown or unlisted specification.

A. Bending properties. For pipe two inches (2") 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") in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A 53, 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") in diameter, at least one (1) test weld must be made for each one hundred (100) lengths of pipe. On pipe four inches (4") 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 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])

III. Steel pipe manufactured before November 12, 1970 to earlier editions of listed specifications. Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I. of this appendix, is qualified for use under this rule if the following requirements are met:

A. 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 that there are no defects which might impair the strength or tightness of the pipe; and

B. Similarity of specification requirements. The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I. of this appendix:

1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation and yield to tensile ratio, and testing requirements to verify those properties.

2) Chemical properties of pipe and testing requirements to verify those properties.

C. Inspection or test of welded pipe. On pipe with welded seams, one (1) of the following requirements must be met:

1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I. of this appendix; or

2) The pipe must be tested in accordance with section (10) of 4 CSR 240-40.030 to at least one and one-fourth (1.25) times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least one and one-half (1.5) times the maximum allowable operating pressure if it is to be installed in a Class 2, 3 or 4 location. Notwithstanding any shorter time period permitted under section (10) of 4 CSR 240-40.030, the test pressure must be maintained for at least eight (8) hours.

Appendix C—Qualification of Welders for Low Stress Level Pipe

I. Basic test. The test is made on pipe twelve inches (12") 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") long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. Additional tests for welders of service line connections to mains. A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap or poor penetration at the junction of the fitting and run pipe.

III. Periodic tests for welders of small service lines. Two (2) samples of the welder's work, each about eight inches (8") 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") 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 D—Criteria for Cathodic Protection and Determination of Measurements

I. Criteria for cathodic protection.

A. Steel, cast iron and ductile iron structures.

1) A negative (cathodic) polarized voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made in accordance with sections II. and IV. of this appendix.

2) A minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

3) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV. of this appendix.

4) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. Aluminum structures.

1) Except as provided in I.B.3) and 4) of this appendix, a minimum negative (cathodic) voltage shift of one hundred fifty (150) millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II. and IV. of this appendix.

2) Except as provided in paragraphs I.B.3) and 4) of this appendix, a minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

3) Notwithstanding the alternative minimum criteria in paragraphs I.B.1) and 2) of this appendix, aluminum, if cathodically protected at voltages in excess of one and two-tenths (1.20) volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV. of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the buildup of alkalis on the metal surface. A voltage in excess of one and two-tenths (1.20) volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

4) Because aluminum may suffer from corrosion under high pH conditions and because application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of eight (8).

C. Copper structures. A minimum negative (cathodic) polarization voltage shift of one hundred (100) millivolts. This polarization voltage shift must be determined in accordance with sections III. and IV. of this appendix.

D. Metals of different anodic potentials. A negative (cathodic) voltage, measured in accordance with section IV. of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs I.B.3) and 4) of this appendix, they must be electrically isolated with insulating flanges or the equivalent.

II. Interpretation of voltage measurement. Voltage (IR) drops other than those across the structure-electrolyte boundary must be adequately compensated for in order to obtain a valid interpretation of the voltage measurement in paragraphs I.A.1) and I.B.1) of this appendix. Possible methods of compensating for IR drops include:

1) Determining the cathodic voltage immediately upon interruption of the protective current; or

2) If interruption of the protective current is impractical for galvanic systems, the voltage measurements must be obtained at locations where the influence of potential gradients from nearby sacrificial anodes is minimized.

III. Determination of polarization voltage shift. The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in I.A.2), I.B.2) and I.C. of this appendix.

IV. Reference half cells.

A. Except as provided in paragraphs IV.B. and IV.C. of this appendix, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two (2) commonly used reference half cells are listed here along with their voltage equivalent to—0.85 volt as referred to a saturated copper-copper sulfate half cell:

1) Saturated KCl calomel half cell:—0.78 volt; and

2) Silver-silver chloride half cell used in sea water:—0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

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

(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)

4 CSR 240-40.030(9) Requirements for Corrosion Control
(A) Scope. (192.451)
(B) Applicability to Converted Pipelines. (192.452)
(C) General. (192.453)
(D) External Corrosion Control—Buried or Submerged Pipelines Installed After July 31, 1971. (192.455)
(E) External Corrosion Control—Buried or Submerged Pipelines Installed Before August 1, 1971. (192.457)
(F) External Corrosion Control—Inspection of Buried Pipeline When Exposed. (192.459)
(G) External Corrosion Control—Protective Coating. (192.461)
(H) External Corrosion Control—Cathodic Protection. (192.463)
(I) External Corrosion Control—Monitoring. (192.465)
(J) External Corrosion Control—Electrical Isolation. (192.467)
(K) External Corrosion Control—Test Stations. (192.469)
(L) External Corrosion Control—Test Leads. (192.471)
(M) External Corrosion Control—Interference Currents. (192.473)
(N) Internal Corrosion Control—General. (192.475)
(O) Internal Corrosion Control—Monitoring. (192.477)
(P) Atmospheric Corrosion Control—General. (192.479)
(Q) Atmospheric Corrosion Control—Monitoring. (192.481)
(R) Remedial Measures—General. (192.483)
(S) Remedial Measures—Transmission Lines. (192.485)
(T) Remedial Measures—Distribution Lines Other Than Cast Iron or Ductile Iron Lines. (192.487)
(U) Remedial Measures—Cast Iron and Ductile Iron Pipelines. (192.489)
(V) Corrosion Control Records. (192.491)

4 CSR 240-40.030(10) Test Requirements
(A) Scope. (192.501)
(B) General Requirements. (192.503)
(C) Strength Test Requirements for Steel Pipelines 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 Above One Hundred (100) psig. (192.507)
(E) Test Requirements for Pipelines to Operate at or Below One Hundred (100) psig. (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(11) Uprating
(A) Scope. (192.551)
(B) General Requirements. (192.553)
(C) Uprating to a Pressure That Will Produce a Hoop Stress of Thirty Percent (30%) or More of SMYS in Steel Pipelines. (192.555)
(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)

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.
(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.

4 CSR 240-40.030(13) Maintenance
(A) Scope. (192.701)
(B) General. (192.703)
(C) Transmission Lines—Patrolling. (192.705)
(D) Transmission Lines—Leakage Surveys. (192.706)
(E) Line Markers for Mains and Transmission Lines. (192.707)
(F) Recordkeeping.
(G) Transmission Lines—General Requirements for Repair Procedures. (192.711)
(H) Transmission Lines—Permanent Field Repair of Imperfections and Damages. (192.713)
(I) Transmission Lines—Permanent Field Repair of Welds. (192.715)
(J) Transmission Lines— Permanent Field Repair of Leaks. (192.717)
(K) Transmission Lines—Testing of Repairs. (192.719)
(L) Distribution Systems—Patrolling. (192.721)
(M) Distribution Systems—Leakage Surveys. (192.723)
(N) Test Requirements for Reinstating Service Lines and Fuel Lines. (192.725)
(O) Abandonment or Deactivation of Facilities. (192.727)
(P) Compressor Stations—Inspection and Testing of Relief Devices. (192.731)
(Q) Compressor Stations—Storage of Combustible Materials and Gas Detection. (192.735 and 192.736)
(R) Pressure Limiting and Regulating Stations—Inspection and Testing. (192.739)
(S) Pressure Limiting and Regulating Stations—Telemetering or Recording Gauges. (192.741)
(T) Pressure Limiting and Regulating Stations—Testing of Relief Devices. (192.743)
(U) Valve Maintenance—Transmission Lines. (192.745)
(V) Valve Maintenance—Distribution Systems. (192.747)
(W) Vault Maintenance. (192.749)
(X) Prevention of Accidental Ignition. (192.751)
(Y) Caulked Bell and Spigot Joints. (192.753)
(Z) Protecting or Replacing Disturbed Cast Iron Pipelines. (192.755)
(AA) Repair of Plastic Pipe.

4 CSR 240-40.030(14) Gas Leaks
(A) Scope.
(B) Investigation and Classification Procedures.
(C) Leak Classifications.

4 CSR 240-40.030(15) Replacement Programs

(A) Scope.

(B) Replacement Programs—General Requirements.

(C) Replacement Program—Unprotected Steel Service Lines and Yard Lines.

(D) Replacement Program—Cast Iron.

(E) Replacement/Cathodic Protection Program—Unprotected Steel Transmission Lines, Feeder Lines and Mains.

4 CSR 240-40.030(16) Waivers of Compliance

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

4 CSR 240-40.040 Uniform System of Accounts—Gas Corporations

PURPOSE: This rule directs gas companies within the commission's jurisdiction to use the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for major natural gas companies, as modified here, to file an annual report, and to submit a revised depreciation study, data base and property unit catalog at least every five years.

Editor's Note: The secretary of state has determined that the publication of this rule in its entirety would be unduly cumbersome or expensive. The entire text of the rule has been filed with the secretary of state and is summarized here by the agency adopting it. The entire text of the rule may be found at the headquarters of the agency and is available to any interested person at a cost established by state law. Citations in this rule beginning with the word Part refer to 18 CFR part 201 (1992); citations beginning with the word paragraph refer to 2 FERC Stat. & Regs. paragraph 20,001 and following (1992).

(1) Beginning January 1, 1994, every gas company subject to the commission's jurisdiction shall keep all accounts in conformity with the Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, as prescribed by the Federal Energy Regulatory Commission (FERC) and published at 18 CFR part 201 (1992) and 2 FERC Stat. & Regs. paragraph 20,001 and following (1992), except as otherwise provided in this rule. This uniform system of accounts provides instruction for recording financial information about gas corporations. It contains definitions; general instructions; gas plant instructions; operating expense instructions; accounts that comprise the balance sheet, gas plant, income, operating revenues, and operation and maintenance expenses.

(2) When implementing 4 CSR 240-40.040(1), each gas company subject to the commission's jurisdiction shall—

(A) Keep its accounts in the manner and detail specified for natural gas companies classified as "major" at Part 201 General Instructions 1.A. and paragraph 20,011.1.A.; and

(B) Assemble by July 1, 1996 and maintain after that, a property unit catalog which contains for each designated property unit, in addition to the provisions of Part 201 General Instructions 6. and paragraph 20,016—

1. A description of each unit;
2. An item list; and
3. Accounting instructions, including instructions for distinguishing between operations expense, maintenance expense and capitalized plant improvements.

(3) Regarding plant acquired or placed in service after 1993, when implementing section (1), each gas corporation subject to the commission's jurisdiction shall—

(A) Maintain plant records of the year of each unit's retirement as part of the "continuing plant inventory records," as the term is otherwise defined at Part 201 Definitions 8. and paragraph 20,001.8.;

(B) State the detailed gas plant accounts (301 to 399, inclusive) on the basis of original cost, estimated if not known, when implementing the provisions of Part 201 Gas Plant Instructions 1.C. and paragraph 20,041.1.C.;

(C) Record gas plant acquired as an operating unit or system at original cost, estimated if not known, except as otherwise provided by the text of the intangible plant accounts, when implementing the provisions of Part 201 Gas Plant Instructions 2.A. and paragraph 20,042.2.A.;

(D) Account for the cost of items not classified as units of property as it would account for the cost of individual items of equipment of small value or of short life, as provided in Part 201 Gas Plant Instructions 3.A.(3) and paragraph 20,043.3.A.(3);

(E) Include in equipment accounts any hand or other portable tools which are specifically designated as units of property, when implementing the provisions of Part 201 Gas Plant Instructions 9.B. and paragraph 20,049.9.B.;

(F) Use the list of retirement units contained in its property unit catalog when implementing the provisions of Part 201 Gas Plant Instructions 10.A. and paragraph 20,050.10.A.;

(G) Estimate original cost with an appropriate average of the original cost of the units by vintage year, with due allowance for any difference in size and character, when it is impracticable to determine the original cost of each unit, when implementing the provisions of Part 201 Gas Plant Instructions 10.D. and paragraph 20,050.10.D.;

(H) Charge original cost less net salvage to account 108., when implementing the provisions of Part 201 Gas Plant Instructions 10.F. and paragraph 20,050.10.F.;

(I) Keep its work order system so as to show the nature of each addition to or retirement of gas plant by vintage year, in addition to the other requirements of Part 201 Gas Plant Instructions 11.B. and paragraph 20,051.11.B.;

(J) Maintain records which classify, for each plant account, the amounts of the annual additions and retirements so as to show the number and cost of the various record units or retirement units by vintage year, when implementing the provisions of Part 201 Gas Plant Instructions 11.C. and paragraph 20,051.11.C.;

(K) Maintain subsidiary records which separate account 108. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Account 108.C. and paragraph 20,011.108.C.;

(L) Maintain subsidiary records which separate account 111. according to primary plant accounts or subaccounts when implementing the provisions of Part 201 Balance Sheet Accounts 111.C. and paragraph 20,114.111.C.; and

(M) Keep mortality records of property and property retirement as will reflect the average life of retiring property and will aid actuarial analysis of the probable service life of annual additions and aged retirements when implementing the provisions of Part 201 Income Accounts 403.B. and paragraph 20,422.403.B.

(4) In prescribing this system of accounts the commission does not commit itself to the approval or acceptance of any item set out in any account, for the purpose of fixing rates or in determining other matters before the commission. This rule shall not be construed as

waiving any recordkeeping requirement in effect prior to 1994.

(5) Each gas corporation subject to the commission's jurisdiction shall submit a depreciation study, data base and property unit catalog to the manager of the commission's energy department, and to the Office of the Public Counsel, as required by the terms of subsection (5)(B).

(A) The depreciation study, data base and property unit catalog shall be compiled as follows:

1. The study shall reflect the average life and remaining life of each primary plant account or subaccount;

2. The data base shall consist of dollar amounts, by plant account or subaccount, representing—

A. Annual dollar additions and dollar retirements by vintage year and year retired, beginning with the earliest year of available data;

B. Reserve for depreciation;

C. Surviving plant balance as of the study date; and

D. Estimated date of final retirement and surviving dollar investment for each warehouse, propane/air production facility, liquefied natural gas facility, underground natural gas storage facility, general office building or other large structure;

3. The property unit catalog shall contain a description of each retirement unit used by the company.

(B) A gas company shall submit its depreciation study, data base and property unit catalog on the following occasions:

1. On or before the date adjoining the first letter of the name under which the corporation does business, excluding the word the, as indicated by the tariffs on file with the commission.

A. The alphabetical categories and submission due dates are as follows:

(I) A, B, C, D: January 1, 1994;

(II) E, F, G, H: July 1, 1994;

(III) I, J, K, L: January 1, 1995;

(IV) M, N, O, P: July 1, 1995;

(V) Q, R, S, T: January 1, 1996;

(VI) U, V, W, X, Y, Z: July 1, 1996.

B. However—

(I) A gas company need not submit a depreciation study, data base or property unit catalog to the extent that the commission's staff received these items from the utility during the three (3) years prior to the due dates listed in subparagraph (5)(B)1.A.; or

(II) A utility with simultaneous due dates under 4 CSR 240-20.030(5)(B)1. and 4 CSR 240-40.040(5)(B)1. may postpone its due date with respect to one (1) of these rules by six (6) months. To exercise this option, the utility must give written notice of its intent to postpone compliance to the manager of the commission's energy department, and to the Office of the Public Counsel, before the utility's first due date;

2. When the utility files its tariff(s) with the commission proposing a general rate increase, as that term is used in the commission's rules pertaining to minimum filing requirements. However, a gas company need not submit a depreciation study, data base or property unit catalog to the extent that the commission's staff received these items from the utility during the three (3) years prior to the utility filing for a general rate increase; or

3. Before five (5) years have elapsed since the last time the commission's staff received a depreciation study, data base and property unit catalog from the utility.

(6) The commission may waive or grant a variance from the provisions of this rule, in whole or in part, for good cause shown, upon a utility's written application.

AUTHORITY: section 393.140, RSMo 1994. Original rule filed Dec. 19, 1975, effective Dec. 29, 1975. Amended: Filed April 26, 1976, effective Sept. 11, 1976. Amended: Filed Feb. 5, 1993, effective Oct. 10, 1993. Amended: Filed March 19, 1996, effective Oct. 30, 1996.*

**Original authority 1939, amended 1949, 1967.*

4 CSR 240-40.050 Gas Leaks
(Rescinded October 10, 1993)

AUTHORITY: section 393.140, RSMo 1986. Original rule filed Dec. 19, 1975, effective Dec. 29, 1975. Rescinded: Filed Feb. 4, 1993, effective Oct. 10, 1993.

4 CSR 240-40.055 Gas Leaks in Unprotected Steel Service Lines

Emergency rule filed Feb. 24, 1989, effective March 6, 1989, expired July 1, 1989.

4 CSR 240-40.060 Gas Used for Decorative Outdoor Lighting

Emergency rule filed Oct. 15, 1979, effective Nov. 5, 1979, expired March 3, 1980.

4 CSR 240-40.061 Gas Used For Decorative Outdoor Lighting
(Rescinded September 25, 1987)

AUTHORITY: section 393.140, RSMo 1978. Emergency rule filed April 22, 1980, effective May 2, 1980, expired Aug. 18, 1980. Original rule filed April 22, 1980, effective Aug. 12, 1980. Emergency amendment filed Dec. 21, 1981, effective Jan. 1, 1982, expires April 10, 1982. Amended: Filed Dec. 21, 1981, effective April 15, 1982. Rescinded: Filed June 25, 1987, effective Sept. 25, 1987.

4 CSR 240-40.070 Minimum Filing Requirements
(Rescinded October 10, 1993)

AUTHORITY: section 393.140, RSMo 1986. Original rule filed Dec. 10, 1979, effective Sept. 1, 1980. Rescinded: Filed Feb. 4, 1993, effective Oct. 10, 1993.

4 CSR 240-40.080 Drug and Alcohol Testing

PURPOSE: This rule adopts the federal regulations on this subject matter that apply to operators of gas systems. The rule requires operators of gas systems to test certain employees for the presence of prohibited drugs or alcohol and provide an employee assistance program. In addition, the rule provides a description of the technical procedures which must be utilized in conducting the drug and alcohol testing. The rule applies to operators of gas systems subject to the safety jurisdiction of the Public Service Commission.

PUBLISHER'S NOTE: The publication of the full text of the material that the adopting agency has incorporated by reference in this rule would be unduly burdensome or expensive. Therefore, the full text of that material will be made available to any interested person at both the Office of the Secretary of State and the office of the adopting state agency, pursuant to section 536.031.4, RSMo. Such material will be provided at the cost established by state law.

(1) As set forth in the *Code of Federal Regulations* (CFR), 49 CFR parts 40 and 199 are incorporated by reference and made a part of this rule.

(2) The commission adopts the federal pipeline safety regulations for drug and alcohol testing, 49 CFR part 199, as rules of the commission.

(3) The commission adopts the federal procedures for transportation workplace drug and alcohol testing programs, 49 CFR part 40, as rules of the commission.

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

(A) The references to "state agency" in sections 199.3, 199.7(b), 199.13(b)(2), 199.17(a), 199.21(b), 199.23(b), 199.205, 199.231(c), 199.231(d), and 199.245(c) of the federal rule should refer to "the commission" instead;

(B) The references to "accident" in sections 199.3, 199.11(b), 199.205, 199.221, 199.223, 199.225(a), and 199.231(e) of the federal rule should refer to a "federal incident reportable under 4 CSR 240-40.020" instead;

(C) The references to "part 192, 193, or 195 of this chapter" or "part 192, 193, or 195" in sections 199.1, 199.3, 199.200, 199.201, and 199.205 of the federal rule should refer to "4 CSR 240-40.030" instead (the commission regulations contained in 4 CSR 240-40.030 parallel 49 CFR part 192, but the commission does not have any rules pertaining to 49 CFR part 193 or 195);

(D) The references to the applicability exemptions for operators of master meter systems as defined in section "191.3 of this chapter" in sections 199.1 and 199.201 of the federal rule should refer to "4 CSR 240-40.020(2)(F)" instead; and

(E) The reference to the applicability exemptions for liquefied petroleum gas (LPG) operators as discussed in section "192.11 of this chapter" in section 199.201 of the federal rule should refer to "4 CSR 240-40.030(1)(F)" instead.

(5) The federal pipeline safety regulations adopted in section (2) of this rule contain subparts on drug testing and alcohol misuse prevention program.

(A) The drug testing subpart contains sections on: scope and compliance; definitions; Department of Transportation (DOT) procedures; anti-drug plan; use of persons who fail or refuse a drug test; drug tests required; drug testing laboratory; review of drug testing results; retention of sample and retesting; employee assistance program; contractor employees; record keeping; and reporting of anti-drug testing results.

(B) The alcohol misuse prevention program subpart contains sections on: purpose; applicability; alcohol misuse plan; alcohol testing procedures; definitions; preemption of state and local laws; other requirements imposed by operators; requirement for notice; starting date for alcohol testing programs; alcohol concentration; on-duty use; pre-duty use; use following an accident; refusal to submit to a required alcohol test; alcohol tests required; retention of records; reporting of alcohol testing results; access to facilities and records; removal from covered function; required evaluation and testing; other alcohol-related conduct; operator obligation to promulgate a policy on the misuse of alcohol; training for supervisors; referral, evaluation, and treatment; and contractor employees.

(6) The federal procedures for transportation workplace drug and alcohol testing programs adopted by reference in section (3) of this rule contain subparts on general, drug testing, alcohol testing, and non-evidential alcohol screening tests.

(A) The general subpart contains sections on applicability and definitions.

(B) The drug testing subpart contains sections on: the drugs; preparation for testing; specimen collection procedures; laboratory personnel; laboratory analysis procedures; quality assurance and quality control; reporting and review of results; protection of employee records; individual access to test and laboratory certification results; and use of Department of Health and Human Services (DHHS) certified laboratories.

(C) The alcohol testing subpart contains sections on: the breath alcohol technician (BAT); devices to be used for breath alcohol tests; quality assurance plans for evidential breath testing devices (EBTs); locations for breath alcohol testing; the breath alcohol testing form; preparation for breath alcohol testing; procedures for screening tests; procedures for confirmation tests; refusals to test and uncompleted tests; inability to provide an adequate amount of breath; invalid tests; availability and disclosure of alcohol testing information about individual employees; and maintenance and disclosure of records concerning EBTs and BATs.

(D) The non-evidential alcohol screening tests subpart contains sections on: authorization for use of non-evidential alcohol screening devices; the screening test technician (STT); quality assurance plans for non-evidential screening devices; locations for non-evidential alcohol screening tests; testing forms; screening test procedure; refusals to test and uncompleted tests; inability to provide an adequate amount of breath or saliva; invalid tests; availability and disclosure of alcohol testing information about individual employees; and maintenance and disclosure of records concerning non-evidential testing devices and STTs.

AUTHORITY: sections 386.250 and 386.310, RSMo Supp. 1997 and 393.140, RSMo 1994. Original rule filed Nov. 29, 1989, effective April 2, 1990. Rescinded and readopted: Filed Jan. 9, 1996, effective Aug. 30, 1996. Rescinded and readopted: Filed April 9, 1998, effective Nov. 30, 1998.*

**Original authority: 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991, 1993, 1995, 1996; 386.310, RSMo 1937, amended 1979, 1989, 1996; and 393.140, RSMo 1939, amended 1949, 1967.*