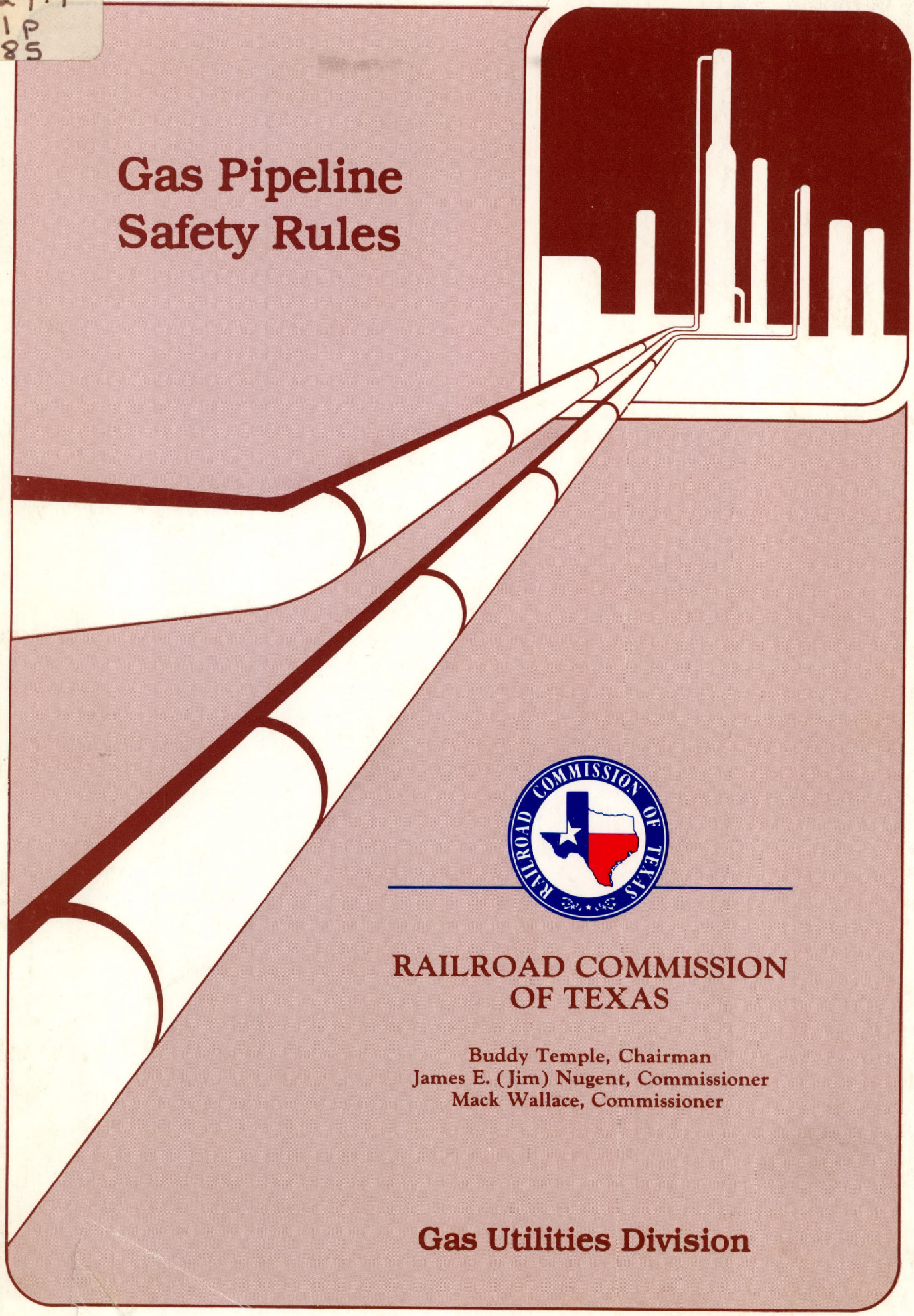
Gas Pipeline Safety Rules



RAILROAD COMMISSION OF TEXAS

Buddy Temple, Chairman
James E. (Jim) Nugent, Commissioner
Mack Wallace, Commissioner

Gas Utilities Division

Rules and Regulations For the Transportation Of Natural And Other Gas by Pipeline

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through December 31, 1984

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Table of Contents

Introduction

This publication is a compilation of the gas pipeline safety rules and regulations which have been adopted and promulgated by the Commission. The inclusion of 49 CFR 191 is done for continuity even though it has not been adopted. Portions of 49 CFR 191 are applicable as they describe Federal Forms required by Gas Utilities Docket 446, Rule 7 (2).

All regulations herein are current through December 31, 1984. All amendments or supplements to that date are inserted in text and a table describing each amendment to Part 192 and listing effective dates to each amendment begins on page 29.

The material herein reproduced was compiled from various sources and errors which may exist are not intentional.

Special Note:

Amendments developed by the Railroad Commission and promulgated on January 21, 1980 are inserted and are underlined in text in the affected sections of 192 listed below:

Definitions	—Added, "Short Section of Pipe"
192.455(b)	—Supplement to First Sentence
192.457(b)(3)	—Supplement to Second Sentence
192.457(d)	—Added New
192.465(a)	—Supplement to First Sentence
192.465(e)	—Supplement to End of Second Sentence
192.465(f)	—Added New
192.475(a)	—Added New Second Paragraph
192.479(c)	—Added New

Part 191--Transportation of Natural and Other Gas by Pipeline: Reports of Leaks

Sec.

DEPARTMENT OF TRANSPORTATION REGULATIONS FOR TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; REPORTS OF LEAKS

(49 CFR 191; 35 FR 320, January 8, 1970; 36 FR 7507, April 2, 1971; 37 FR 1173, January 26, 1972; 46 FR 37250, July 20, 1981; 47 FR 32719, July 29, 1982; 49 FR 18956, May 3, 1984)

191--Transportation of Natural and Other Gas by Pipeline; Reports of Leaks

191.1 **SCOPE.**

[49 FR 18956, May 3, 1984; effective June 4, 1984]

(a) This part prescribes requirements for the reporting of incidents and annual pipeline summary data by operators of gas pipeline facilities located in the United States or Puerto Rico, including pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).

(b) This part does not apply to—

(1) Offshore gathering of gas upstream from the outlet flange of each facility on the Outer Continental Shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream; or

(2) Onshore gathering of gas outside of the following areas:

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

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

191.3 **DEFINITIONS.**

As used in this part and in the RSPA Forms referenced in this part—

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

Incident means any of the following events:

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

(i) A death, or personal injury necessitating in-patient hospitalization; or

(ii) Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.

(2) An event that results in an emergency shutdown of an LNG facility,

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

[49 FR 18956, May 3, 1984; effective June 4, 1984]

LNG Facility means a liquefied natural gas facility as defined in §193.2007 of Part 193 of this Chapter;

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, such as by rents;

[49 FR 18956, May 3, 1984, effective June 4, 1984]

Municipality means a city, county, or any other political subdivision of a State;

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters;

[49 FR 18956, May 3, 1984; effective June 4, 1984]

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

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof;

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 appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

[49 FR 18956, May 3, 1984; effective June 4, 1984]

Secretary means the Secretary of Transportation or any person to whom he has delegated authority in the matter concerned;

State includes each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico;

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.

191.5 TELEPHONIC NOTICE OF CERTAIN LEAKS

(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.

[49 FR 18956, May 3, 1984; effective June 4, 1984]

(b) Each notice required by pargraph (a) of this section shall be made by telephone to 800-424-8802 (in Washington, D.C., 426-2675) and shall include the following information.

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

(2) The location of the incident.

(3) The time of the incident.

(4) The number of fatalities and personal injuries, if any.

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

[49 FR 18956, May 3, 1984; effective June 4, 1984]

191.7 ADDRESSEE FOR WRITTEN REPORTS.

[49 FR 18956, May 3, 1984; effective June 4, 1984]

Each written report required by this part must be made to the Information Systems Manager, Materials Transportation Bureau, Department of Transportation, Washington, D.C. 20590. However, reports for intrastate pipelines subject to the jurisdiction of a State agency pursuant to certification under section

5(a) of the Natural Gas Pipeline Safety Act of 1968 may be submitted in duplicate to the State agency if the regulations of that agency require submission of these reports and provide for further transmittal of one copy, within 10 days of receipt for incident reports and not later than March 15 for annual reports, to the Information Systems Manager, Materials Transportation Bureau, Department of Transportation, Washington, D.C. 20590.

191.9 DISTRIBUTION SYSTEM: INCIDENT REPORT

[49 FR 18956, May 3, 1984; effective June 4, 1984]

(a) Except as provided in paragraph (c) of this section, each operator of a distribution pipeline system shall submit Department of Transportation Form RSPA F 7100.1 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

(b) When additional relevant information is obtained after the report is submitted under paragraph (a) of this section, 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.

191.11 DISTRIBUTION SYSTEM: ANNUAL REPORT

[49 FR 18956, May 3, 1984; effective June 4, 1984]

(a) Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system shall submit an annual report for that system on Department of Transportation Form RSPA F 7100.1-1. This report must be submitted each year, not later than March 15 for the preceding calendar year.

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

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

(2) Master meter systems; or

(3) LNG facilities.

191.13 DISTRIBUTION SYSTEMS REPORTING TRANSMISSION PIPELINES; TRANSMISSION OR GATHERING SYSTEMS REPORTING DISTRIBUTION PIPELINES.

[49 FR 18956, May 3, 1984; effective June 4, 1984]

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 §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 §191.9 and 191.11.

191.15 TRANSMISSION AND GATHERING SYSTEMS: INCIDENT REPORT.

[49 FR 18956, May 3, 1984; effective June 4, 1984]

(a) Except as provided in paragraph (c) of this section, each operator of a transmission or a gathering pipeline system shall submit Department of Transportation Form RSPA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

(b) Where additional related information is obtained after a report is submitted

under paragraph (a) of this section, 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 paragraph (a) of this section need not be submitted with respect to LNG facilities.

[49 FR 18956, May 3, 1984; effective June 4, 1984]

191.17 TRANSMISSION AND GATHERING SYSTEMS: ANNUAL REPORT

[49 FR 18956, May 3, 1984; effective June 4, 1984]

(a) Except as provided in paragraph (b) of this section, each operator of a transmission or a gathering pipeline system shall submit an annual report on Department of Transportation Form RSPA F 7100.2-1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) The annual report required by paragraph (a) of this section need not be submitted with respect to LNG facilities.

191.19 REPORT FORMS.

Copies of the prescribed report forms are available without charge upon request from the address given in 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 Secretary.

[46 FR 37250, July 20, 1980, effective immediately]

[**Editor's Note:** Copies of the forms and instructions for preparing them are published beginning page 8.]

191.21 OMB CONTROL NUMBER ASSIGNED TO INFORMATION COLLECTION

[49 FR 18956, May 3, 1984; effective June 4, 1984]

This section displays the control number assigned by the Office of Management and Budget (OMB) to the gas pipeline information collection requirements of the Materials Transportation Bureau pursuant to the Paperwork Reduction Act of 1980, Pub. L. 96-511. It is the intent of this section to comply with the requirements of Section 3507(f) of the Paperwork Reduction Act which requires that agencies display a current control number assigned by the Director of OMB for each agency information collection requirement.

OMB Control Number 2137-0522 (approved through March, 1986).

Section of 49 CFR Part 191 where identified	Form No.
191.5	Telephonic
191.9	RSPA 7100.1
191.11	RSPA 7100.1-1
191.15	RSPA 7100.2
191.17	RSPA 7100.2-1

(49 U.S.C. 1681(b) and 1808(b); 49 CFR 1.53, and Appendix A of Part 1)

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

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 ☐ Meter Set Assembly
   ☐ Service Line ☐ Other _____
3. Material Involved:
   ☐ Steel ☐ Cast iron
   ☐ Polyethylene plastic ☐ Other plastic: _____
   ☐ Other _____
   NPS *(Nominal Pipe Size)* /_/_/_/_/ in. Wall Thickness /_/_/_/_/ in.
4. Specification _____ Manufacturer _____ Year Manufactured /_/_/_/_/ Year installed /_/_/_/_/
2. Component Which Failed
   a. Part
   ☐ Body of Pipe ☐ Valve
   ☐ Joint, type _____ ☐ Regulator/meter
   ☐ Fitting ☐ Weld, specify _____ girth, longitudinal, fillet
   ☐ Drip/Riser ☐ Other _____

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)

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
   - ☐ Physical Damage During Construction
   - ☐ Operating Procedure Inappropriate
   - ☐ Other _____
   - ☐ Error in Operating Procedure Application

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

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

4. HEADQUARTERS NAME & ADDRESS IF DIFFERENT

5. STATES IN WHICH SYSTEM OPERATES _____

PART B – SYSTEM DESCRIPTION

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 (3-84)

PART C – TOTAL LEAKS

CAUSE	ELIMINATED/REPAIRED 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

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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 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)

Reproduction of this form is permitted.

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

U.S 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

/ / / / /

5. HEADQUARTERS NAME & ADDRESS, IF DIFFERENT

_____

_____

_____

PART B – SYSTEM DESCRIPTION

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

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 (3-84)

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**Information Systems Manager
Materials Transportation Bureau, DMT-63
400 Seventh Street, S.W.
Washington, D.C. 20590**

The following instructions for completing the incident and annual reporting forms required by 49 CFR Part 191 are included here as guides to completing the forms. These instructions are not a part of the regulation and are subject to modification and change as necessity dictates.

Instructions for Completing Form RSPA F 7100.1 Incident Report—Gas Distribution System

GENERAL INSTRUCTIONS

Each operator of a gas distribution system, except those exempted in §191.9(c), shall file Form RSPA 7100.1 for any incident which meets the criteria specified in §191.5 as soon as practicable but not more than 30 days following the occurrence of the incident.

Reports should be made to the: Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street SW., Washington, D.C. 20590. However, reports for intrastate pipelines subject to the jurisdiction of a State agency pursuant to certification under Section 5(a) of the Natural Gas Pipeline Safety Act of 1968 may be submitted in duplicate to the State agency if the regulations of that agency require submission of these reports and provide for further transmittal of one copy within 10 days of receipt after the incident has occurred to the: Information Systems Manager (DMT-63), Materials Transportation Bureau.

Type or print the operator name and address data in the appropriate location, including the name of the branch or subsidiary, if different, where the incident occurred.

If you have any questions concerning this report or these instructions, or if you need copies of Form RSPA F 7100.1 or the instructions, please write or call the Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, SW., Washington, D.C. 20590, telephone number (202) 472-1024.

For the purpose of completing Form RSPA F 7100.1, the following definitions of terms are to be used when filing Form RSPA F 7100.1 in conjunction with these instructions:

1. *Gas distribution line*—A pipeline other than a gathering or transmission line.

2. *Pipeline*—All parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to the pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

3. *Operator*—A person who engaged in the transportation of gas.

SPECIAL INSTRUCTIONS

An entry should be made in each block for which data are available. In blocks requiring numbers, all blocks should be filled in using zeroes when appropriate. When decimal points are required, the decimal point should be placed in a separate block.

Examples: (Part 4.3) Nominal Pipe Size /0/0/2/4/ inches; /1/./2/5/ inches.

Wall Thickness /./5/0/0/ inches; /./1/4/5/ inches.

Avoid "Unknown" entries if possible. Estimated data are preferrable to unknown data. If "Unknown" or estimated data entries are made, a supplemental report should follow if the data should become known by the operator.

If "Other" is checked in any part of the report, include an explanation or description on the line adjacent to the item checked.

SPECIFIC INSTRUCTIONS

PART 1

The operator's five digit identification number will be assigned by RSPA. If the identification number is not available to the person completing the report, this information should be omitted. Address in Part 1.1.C is address of office originating incident report.

Data on the location of the incident should be as complete as possible, including the nearest city or town, the county or parish, township, borough, etc. Use data that would help orientation with a map and provide such other location information as may be available. The class location should be the class location at the incident site following as closely as possible these designations as excerpted from §192.5 of the gas pipeline safety standards.

192.5 **CLASS LOCATIONS.**

(a) Offshore is Class 1 location. The Class location onshore is determined by applying the criteria set forth in this section: The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Except as provided in paragraphs (d)(2) and (f) of this section, the class location is determined by the buildings in the class location unit. For the purposes of this section, each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

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

(c) A Class 2 location is any class location unit that has more that 10 but less than 46 buildings intended for human occupancy.

(d) A Class 3 location is—

(1) Any class location unit that has 46 or more buildings intended for human occupancy; or

(2) An area where the pipeline lies within 100 yards of any of the following:

(i) A building that is occupied by 20 or more persons during normal use.

(ii) A small, well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater, or other place of public assembly.

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

1.3

The time of the incident should be indicated in reference to a 24-hour clock.

Examples:

1. (0000) = midnight = /0/0/0/0/.
2. (0800) = 8:00 a.m. = /0/8/0/0/.
3. (1200) = Noon = /1/2/0/0/.
4. (1715) = 5:15 p.m. = /1/7/1/5/.
5. (2200) = 10:00 p.m. = /2/2/0/0/.

1.4

In-patient hospitalization means admission and confinement in a hospital beyond treatment administered in an emergency room or outpatient clinic in which confinement does not occur. The property damage/loss estimate is the estimate of total property damage or loss to the operator's property, the property of others, or the combination of both. Loss of gas is a property loss.

Check "Supplemental Report" if this is a follow-up report with additional or corrected information. Do not fill in any previously submitted information with

the exception of "report date," "operator's name," "address," and "preparer." Submit only amended, revised, or added information.

1.5

Elapsed time until the area was made safe means the elapsed time from the time of the occurrence of the incident until the incident is brought under control so that it does not present a significant threat to public safety. This does not necessarily mean that the flow of gas has been stopped completely. If the time of occurrence is unknown, the time when the operator is first notified or made aware of the incident may be utilized.

PART 2

DEFINITION OF CAUSES

1. *Corrosion*—Escape of gas resulting from a hole in the pipeline or component caused by galvanic, stray current, or other corrosive action.

2. *Outside Force-Third Party/Outside Party*—Damage directly attributed to the striking of a gas pipeline facility caused by earth moving equipment, other equipment, tools, vehicles, vandalism, etc. Damage is by personnel other than those working for the operator.

3. *Outside Force-Natural Forces*—Damage resulting from earth movement not caused by man, including earthquakes, washouts, land slides, frost, etc. Also included is damage by lightning, ice, snow, etc.

4. *Accidentally Caused by Operator*—Damage resulting from an inappropriate procedure or a wrong application of a procedure by the operator's employee or the employee of a contractor working for the operator.

5. *Construction Defect/Operating Error*—A "Construction defect" is one resulting from failure of original sound material that is due to outside force being applied during field construction which caused a dent, gouge, excessive stress, or other defect which resulted in subsequent failure. Also include faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site.

6. *Other*—A cause that cannot be identified clearly as belonging in one of the above categories.

If the "Other" block is checked, the narrative in Part 3 should describe the incident in detail, including the known or presumed cause.

PART 3

The narrative is needed only when it is useful to clarify or explain unusual conditions. It should be a concise description of the incident, including the probable cause and conditions which the operator believes may have contributed either directly or indirectly to the cause of the incident. Explanations of estimated data also may be included in the narrative.

PART 4

4.1

Meter Set Assembly is the piping installed to connect the inlet side of the meter to the gas service line and to connect the outlet side of the meter to the customer's fuel line. A service regulator should be included under "2. Component which failed."

4.2

Insert type of joint (other than a weld), such as mechanical, impression, threaded, or fusion.

For a weld joint, check "weld" and specify type.

4.3

For "other," state copper, aluminum, wrought iron, etc.

4.4

This applies to all items in 4.3 and, where appropriate, to items in 4.2. In the event that more than one item has failed, so that origin is not clear, use Part D to complete 4.4 for the additional item(s).

The specification, when known, is the specification to which the pipe or component was manufactured, such as API 5L, ASTM A106, ANSI A21.9, etc. A list of referenced specifications is shown in the Appendix to 49 CFR Part 192. If the pipe or component predates 49 CFR 192, and was manufactured under a specification not listed in 49 CFR 192, put in, when known, the specification to which the pipe or component was manufactured.

Answer all questions for all pipe or components. If not available, mark "N/A."

Year installed means the year of installation at incident location.

PART 5

More than one box can be checked with an indication as to which box is the most appropriate environmental description.

"Under pavement" includes under streets, sidewalks, paved roads, parking lots, shopping centers, etc.

PART 6

"Preparer" is the name of the person most knowledgeable about the information submitted in the report or the person to be contacted for additional information.

"Authorized Signature" may be the "preparer" or an officer or other person whom the operator has designated to review and sign reports of this nature.

PART A

A.5

"Under cathodic protection" means cathodic protection in accordance with the requirements for Part 192 as determined by the criteria in Part 192, Appendix D. If the operator determines the cause of the corrosion to be bacterial or chemical action or stray current, check "Other" in item 3, and indicate the cause.

For the purpose of this report, galvanized pipe with no dielectric coating is to be considered "bare."

PART B

B.1

"Outside Party" (third party) means other than the operator or his agent. Acts of vandalism should be included here.

B.2.a

"Prior notification" means that the operator had been notified that excavation or construction work was to be done in the vicinity of the pipeline prior to the time the incident occurred.

B.3

Additional information, if any, should include a description of other steps taken by the operator to protect the facility against damage by outside forces. A description of an act of vandalism may be included here.

PART C

Definitions:

1. *Poor Workmanship—During Construction*—Wrong mechanical application of the correct procedure.

2. *Operating Procedure Inappropriate*—Wrong procedure was used for this application.

3. *Error in Procedure Application*—Misinterpretation of procedure during field application.

4. *Physical Damage During Construction*—Construction activity damage to existing or newly installed facilities, such as a gouge or dent,

misalignment, or improper support, caused by the operator's personnel or the operator's contractor.

Instructions for Completing Form RSPA F 7100.2 Incident Report—Gas Transmission and Gathering Systems

GENERAL INSTRUCTIONS

Each operator of a gas transmission or gathering system, except those exempted in §191.15(c), shall file Form RSPA F 7100.2 for any incident which meets the criteria specified in §191.5 as soon as practicable but not more than 30 days following the occurrence of the incident.

Reports should be made to the: Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, SW., Washington, D.C. 20590. However, reports for intrastate pipelines subject to the jurisdiction of a State agency pursuant to certification under Section 5(a) of the Natural Gas Pipeline Safety Act of 1968 may be submitted in duplicate to the State agency if the regulations of that agency require submission of these reports and provide for further transmittal of one copy within 10 days of receipt after the incident has occurred to the: Information Systems Manager (DMT-63), Materials Transportation Bureau.

Type or print the operator name and address data in the appropriate location, including the name of the branch or subsidiary, if different, where the incident occurred.

If you have any questions concerning this report or these instructions, or if you need copies of Form RSPA F 7100.2 or the instructions, please write or call the Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, SW., Washington, D.C. 20590, telephone number (202) 472-1024.

For the purpose of completing Form RSPA F 7100.2, the following definitions apply:

1. *Gathering line*—A pipeline that transports gas from a current production facility to a transmission line or main.

2. *Transmission line*—A pipeline, other than a gathering line, that:

a. Transports gas from a gathering line or storage facility to a distribution center or storage facility;

b. Operates at a hoop stress of 20 percent or more of SMYS; or

c. Transports gas within a storage field.

3. *Transmission line of distribution system*—A pipeline within a distribution system that operates at a hoop stress of 20 percent or more of SMYS.

4. *Pipeline*—All parts of these physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to the pipe, compressor units, metering stations, and fabricated assemblies.

5. *Leak*—An unintentional escape of gas from the pipeline. The source of the leak may be:

a. Holes.

b. Cracks—which include propagating and nonpropagating, longitudinal, and circumferential.

c. Separation or pull.

d. Loose connections.

6. *Ruptures*—A complete failure of any portion of the pipeline.

7. *Propagation*—The extension of the original opening in the pipeline in an area

of nominal wall thickness resulting from the internal/external forces on the pipeline.

8. *Tear*—An extension of the original opening in the pipeline resulting from an externally applied force or forces, i.e., a bulldozer, backhoe, grader, etc.

SPECIAL INSTRUCTIONS

An entry should be made in each block for which data are available. In blocks requiring numbers, all blocks should be filled in using zeroes when appropriate. When decimal points are required, the decimal point should be placed in a separate block.

Examples: (Part 5) Nominal Pipe Size /0/0/2/4/ inches; /1/./5/0/ inches

Wall thickness /./5/0/0/ inches; /1/./2/5/ inches.

Avoid "Unknown" entries if possible. Estimated data are preferable to unknown data. If "Unknown" or estimated data entries are made, a supplemental report should follow if the data should become known by the operator.

If "Other" is checked in any part of the report, include an explanation or description on the line adjacent to the item checked.

SPECIFIC INSTRUCTIONS

PART 1

1.1

The operator's five digit identification number will be assigned by RSPA. If the identification number is not available to the person completing the report, this information should be left blank.

Address in 1.1.C is address of office originating incident report.

1.2

Data on the location of the incident should be as complete as possible. Use your normal designation for location or any combination of designations as available or appropriate, including the nearest city or town, the county or parish, township, borough, etc. Use data that would help orientation with a map. Offshore incident identification should be located by State or outer continental shelf identification and block identification. Provide such other location information as may be available. The class location should be the class location at the incident site following as closely as possible these designations as excerpted from 49 CFR 192.5.

192.5 CLASS LOCATIONS.

(a) Offshore is Class 1 location. The Class location onshore is determined by applying the criteria set forth in this section: The class location unit is an area that extends 200 yards on either side of the centerline of any continuous 1-mile length of pipeline. Except as provided in paragraphs (d)(2) and (f) of this section, the class location is determined by the buildings in the class location unit. For the purposes of this section, each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

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

(c) A Class 2 location is any class location unit that has more than 10 but less than 46 buildings intended for human occupancy.

(d) A Class 3 location is—

(1) Any class location unit that has 46 or more buildings intended for human occupancy; or

(2) An area where the pipeline lies within 100 yards of any of the following:

(i) A building that is

occupied by 20 or more persons during normal use.

(ii) A small, well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area, outdoor theater, or other place of public assembly.

(e) A Class 4 location is any Class location unit where buildings with four or more stories above ground are prevalent.

1.3

Refer to the definitions in the General Instructions to classify the incident as a leak, rupture, or other.

1.4

"In-patient hospitalization" means admission and confinement in a hospital beyond treatment administered in an emergency room or out-patient clinic in which confinement does not occur. The property damage/loss estimate is the estimate of total property damage or loss to the operator's property, the property of others, or the combination of both. Loss of gas is a property loss.

Check "Supplemental Report" if this is a follow-up report with additional or corrected information. Do not fill in any previously submitted information with the exception of "report date," "operator's name," "address," and "preparer." Submit only amended, revised, or added information.

1.5

Elapsed time until the area was made safe means the elapsed time from the time of the occurrence of the incident until the incident is brought under control so that it does not present a significant threat to public safety. This does not necessarily mean that the flow of gas has been stopped completely. If the time of occurrence is unknown, the time when the operator is first notified or made aware of the incident may be utilized.

1.8

The time of the incident should be indicated in reference to a 24-hour clock.

Examples:

1. (0000) = midnight.
2. (0800) = 8:00 a.m.
3. (1200) = Noon.
4. (1715) = 5:15 p.m.
5. (2200) = 10:00 p.m.

PART 3

(See instructions for Part A, B, and C.)

PART 3

The narrative is needed only when it is useful to clarify or explain unusual conditions. It should be a concise description of the incident, including the probable cause and conditions which the operator believes may have attributed either directly or indirectly to the cause of the incident. Explanations of estimated data also may be included in the narrative. If the "Other" block is checked, the narrative in Part 3 should describe the incident in detail, including the known or presumed cause.

PART 4

4.4.b

Year installed means the year of installation at incident location.

PART 5

5.1

Nominal pipe size is the diameter normally used to describe the pipe size, i.e., 2 inch, 4 inch, 8 inch, 12 inch, 30 inch, etc.

5.3

This applies to all items in 4.3 and, where appropriate, to items in 4.2. In the event that more than one item has failed, so that origin is not clear, use Part C.4 to complete 4.4 for the additional item(s).

The specification, when known, is the specification to which the pipe or component was manufactured, such as API 5L, ASTM A106, ANSI A21.9, etc. A list of referenced specifications is shown in the Appendix to 49 CFR Part 192. If the pipe or component predates 49 CFR Part 192, and was manufactured under a specification not listed in 49 CFR Part 192, put in, when known, the specification to which the pipe or component was manufactured.

Answer all questions for all pipe or components. If not available, mark "N/A."

PART 6

"Under pavement" includes under streets, sidewalks, paved roads, parking lots, shopping centers, etc.

PART 7

"Preparer" is the name of the person most knowledgeable about the information submitted in the report of the person to be contacted for additional information.

"Authorized Signature" may be the "Preparer," or an officer, or other person whom the operator has designated to review and sign reports of this nature

PART A

A.5

"Under cathodic protection" means cathodic protection in accordance with the requirements for part 192 as determined by the criteria in Part 192, Appendix D. If the operator determines the cause of the corrosion to be bacterial or chemical action or stray current, check "Other" in item 3, and indicate the cause.

For the purpose of this report, galvanized pipe with no dielectric coating is to be considered "bare."

PART B

B.1

"Outside Party" (third party) means other than the operator, or his agent. Acts of vandalism should be included here.

B.2.a

"Prior notification" means that all the operators had been notified that excavation or construction work was to be done in the vicinity of the pipeline prior to the time the incident occurred.

B.3

Additional information, if any, should include a description of other steps taken by the operator to protect the facility against damage by outside forces. A description of an act of vandalism may be included here.

PART C

C.1

A "construction defect" is one resulting from failure of original sound material that is due to outside force being applied during field construction which caused a dent, gouge, excessive stress, or other defect which resulted in subsequent failure. Also included would be faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site.

A "material defect" is one resulting from a defect within the material of the pipe or component or the longitudinal weld/seam that is due to faulty manufacturing procedures.

Instructions for Completing Form RSPA F 7100.1-1 Annual Report for Calendar Year 19—— Gas Distribution System

GENERAL INSTRUCTIONS

Each operator of a distribution system, except those exempted in §191.11(b), is required to file an annual report. Definitions are as follows:

1. "Distribution line" means a pipeline other than a gathering or transmission line.

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

*3. "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 or storage facility;

b. Operates at a hoop stress of 20 percent or more of SMYS. or

c. Transports gas within a storage field.

4. "Operator" means a person who engages in the transportation of gas.

The reporting requirements are contained in Part 191 of Title 49 of the Code of Federal Regulations, "Transportation of Natural and Other Gas by Pipeline: Annual Reports and Incident Reports." Except as provided in §191.11(b), each operator of a distribution system must submit an annual report Form RSPA F 7100.1-1 for the preceding calendar year not later than March 15.

Reports should be sent to the: Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, SW., Washington, D.C. 20590. However, reports for intrastate pipelines subject to the jurisdiction of a State agency pursuant to certification under Section 5(a) of the Natural Gas Pipeline Safety Act may be submitted in duplicate to the State agency if the regulations of the agency require the submission of the reports and provide for further transmittal of one copy to the: Information Systems Manager (DMT-63), Materials Transportation Bureau. The operator filing this report should ensure that the regulations of the State agency provide for further transmittal of one copy of the report to MTB, as specified to be received by March 15 of each year.

Type or print the operator name and address data in the appropriate location.

The annual reporting period is on a calendar basis, beginning January 1 and ending on December 31 of each year.

It is preferred that each independent subsidiary or affiliate operation be reported separately. Satellite divisions that have independent operations and distribution systems should continue to be reported as separate distribution systems even though, through mergers and consolidations, they no longer are separate companies and function as a unified operation under a single corporate headquarters.

If you have any questions concerning this report or these instructions, or if you need copies of Form RSPA F 7100.1-1 or the instructions, please write or call the Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, SW., Washington, D.C. 20590, telephone number (202) 472-1024.

SPECIFIC INSTRUCTIONS

An entry should be made in each block for which data are available. All figures are

*If the operator determines that he has pipelines that fall under definition 3, he should refer to the instructions for completing Form RSPA 7100.2-1 for transmission and gathering systems.

to be reported as whole numbers. *Do Not Use Decimals or Fractions.* Decimals or fractions should be rounded to the nearest whole number— ½ or .5 should be rounded up. Be careful to use "miles" of mains and not "feet;" use "number" of services rather than miles. The "number" of services is the number of service lines and *not* the number of customer served.

Check "Supplemental Report" if this is a follow-up report with additional or corrected information. Do not fill in any previously submitted information with the exception of "report date," "operator's name," "address," and "preparer." Submit only amended, revised, or added information.

Avoid "Unknown" entries if possible. Estimated data are preferable to unknown data.

PART A

The address shown should be the address where information regarding this report can be obtained.

The operator's five digit identification number will be assigned by RSPA. If the identification number is not available to the person completing the report, this information may be omitted. If the pipeline system being reported on is located in more than one State, indicate all States in which this system operates.

PART B

"Coated" means pipe coated with any effective hot or cold applied dielectric coating or wrapper.

"PVC" means polyvinyl chloride plastic.

"PE" means polyethylene plastic.

"ABS" means acrylonitrile-butadiene-styrene plastic.

"Cathodically protected" applies to both "bare" and "coated."

"Other Pipe" means a pipe of any material not specifically designated on the form. An explanation should be included in Part F if "Other Pipe" is marked. If an operator has, in the past, kept records which have consolidated wrought iron pipe with steel pipe, then he may continue to do so.

"Number of services" is the number of service lines and *not* the number of customers served.

PART C

This section includes all reportable incidents and nonreportable leaks (not reported in accordance with §191.5) repaired or eliminated during the one calendar year which is indicated by the operator on the "Annual Report" form.

Leaks are defined as follows; An unintentional escape of gas from the pipeline.

A reportable incident is one which meets the specific criteria of §191.5. Leaks/incidents are classified as follows:

"Corrosion"—escape of gas resulting from a hole in the pipeline or component caused by galvanic, bacterial, chemical, stray current, or other corrosive action.

"Third Party"—outside force damage directly attributed to the striking of gas pipeline facilities by earth moving equipment, other equipment, tools, vehicles, vandalism, etc. Damage is by personnel other than the operator or the contractor working for the operator.

"Outside Force"—damage resulting from earth movement not caused by man, including earthquakes, washouts, land slides, frost, etc. Also included is damage by lightning, ice, snow, etc.

A "Construction Defect" is one resulting from failure of original sound material that is due to external force being applied during field construction which caused a dent, gouge, excessive stress, or other defect which resulted in subsequent

failure. Also included are faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site.

A "Material Defect" is one resulting from a defect within the material of the pipe or component or the longitudinal weld/seam that is due to faulty manufacturing procedures.

"Other" would be the result of any other cause, such as equipment operating malfunction, failure of mechanical joints, or connections not attributable to any of the above.

Indicate all leaks eliminated during the reporting year, including those reported on Form RSPA F 7100.1, "Incident Report, Distribution Systems." Do not include test failures.

Include all leaks eliminated by repair or by replacement of the pipe or other component.

PART D

Federal lands—

For the purposes of completing Form RSPA F 7100.1-1, indicate only those leaks repaired, eliminated, or scheduled for repair during the reporting year, including those incidents reported on Form RSPA F 7100.1.

PART E

State the amount of unaccounted for gas as a percent of total input for the 12 months ending June 30 of the reporting year. (purchased gas + produced gas) minus (customer use + company use) divided by (purchased gas + produced gas) equals percent unaccounted for.

PART F

Include any additional information which will assist in clarifying or classifying data included in this report.

PART G

"Preparer" is the name of the person most knowledgeable about the information submitted in the report or the person to be contacted for additional information.

"Authorized Signature" may be the "Preparer" or an officer or other person whom the operator has designated to review and sign reports of this nature.

Instructions for Completing Form RSPA F 7100.2-1, Annual Report for Calendar Year 19—— Gas Transmission and Gathering Systems

GENERAL INSTRUCTIONS

Each operator of a gathering system in a *nonrural* area, or of a transmission system, is required to file an annual report. Definitions are as follows:

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

2. "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 or storage facility;

b. Operates at a hoop stress of 20 percent or more or SMYS; or

c. Transports gas within a storage field.

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

4. "Offshore means beyond the line of ordinary low water along that portion of

*If the operator determines that he has pipelines that fall under this definition, he should refer to the instructions for completing Form RSPA F 7100.1-1 for distribution lines.

the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

The reporting requirements are contained in Part 191 of Title 49 of the Code of Federal Regulations, "Transportation of Natural and Other Gas by Pipeline: Annual Reports and Incident Reports." Each operator of a nonrural gathering system or of a transmission system must submit an annual report Form RSPA F 7100.2-1 for the preceding calendar year not later than March 15.

Reports should be sent to the: Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, SW., Washington, D.C. 20590. However, reports for intrastate pipelines subject to the jurisdiction of a State agency pursuant to certification under Section 5(a) of the Natural Gas Pipeline Safety Act may be submitted in duplicate to the State agency if the regulations of that agency require the submission of these reports and provide for further transmittal of one copy to the: Information Systems Manager (DMT-63), Materials Transportation Bureau. The operator filing this report should ensure that the regulations of the State agency provide for further transmittal of one copy of the report of MTB, as specified to be received by March 15 of each year.

Type or print the operator name and address data in the appropriate location.

The annual reporting period is on a calendar basis, beginning January 1 and ending on December 31 of each year.

It is preferred that each independent subsidiary or affiliate operation be reported separately. Satellite divisons that have independent operations and transmission or gathering systems should continue to be reported as separate systems even though, through mergers and consolidations, they no longer are separate companies and function as a unified operation under a single corporate headquarters.

If you have any questions concerning this report or these instructions, or if you need copies of Form RSPA F 7100.2-1 or the instructions, please write or call the Information Systems Manager (DMT-63), Materials Transportation Bureau, Department of Transportation, 400 Seventh Street, SW., Washington, D.C. 20590, telephone number (202) 472-1024.

SPECIFIC INSTRUCTIONS

An entry should be made in each block for which data are available. All figures are to be reported as whole numbers. *Do Not Use Decimals Or Fractions.* Decimals or fractions should be rounded to the nearest whole number— or .5 should be rounded up. Be careful to use "miles" of pipeline and not "feet."

Avoid "Unknown" entries if possible. Estimated data are preferable to unknown data.

Check "Supplemental Report" if this is a follow-up report with additional or corrected information. Do not fill in any previously submitted information with the exception of "report date," "operator's name," "address," and "preparer." Submit only amended, revised, or added information.

PART A

The address shown should be the address where information regarding this report can be obtained.

The operator's five digit identification number will be assigned by RSPA. If the identification number is not available to the person completing the report, this information may be omitted. If the pipeline system being reported on is located in more than one State, indicate all States in which this system operates.

PART B

"Coated" means pipe coated with any effective hot or cold applied dielectric coating or wrapper.

"Other Pipe" means a pipe or any material not specifically designated on the form, such as copper, aluminum, etc. An explanation should be included with the form if "Other Pipe" is marked.

PART C

This section includes all reportable incidents and nonreportable leaks repaired or eliminated during the calendar year which is indicated by the operator on the "Annual Report" form.

Leaks are defined as follows:An unintentional escape of gas from the pipeline.

A reportable incident is one which meets the specific criteria of §191.5

"Corrosion" is the escape of gas resulting from a hole om contact of the pipeline with earth moving or other equipment, tools, vehicles, or movement of in the pipe or other component caused by galvanic, bacterial, chemical, stray current, or other corrosive action.

"Outside Forces" is damage resulting from contact of the pipeline with earth moving or other equipment, tools, vehicles or movement of the earth surrounding the pipeline, such as landslides. Also included are incidents caused by fire or lightning, and deliberate or willful acts, such as vandalism.

A "Construction Defect" is one resulting from failure of original sound material that is due to outside force being applied during field construction which caused a dent, gouge, excessive stress, or other defect which resulted in subsequent failure. Also included are faulty wrinkle bends, faulty field welds, and damage sustained in transportation to the construction or fabrication site.

A "Material Defect" is one resulting from a defect within the material of the pipe or component or the longitudinal weld/seam that is due to faulty manufacturing procedures.

"Other" would be the result of any other cause, such as equipment operating malfunction, failure of mechanical joints, or connections not attributable to any of the above.

Indicate all leaks repaired or eliminated during the reporting year, including those reported on Form RSPA F 7100.2, "Incident Report, Transmission and Gathering Systems." Do not include test failures.

Include all leaks eliminated by repair or by replacement of the pipe or other component.

PART D

Federal lands—

For the purpose of completing Form RSPA F 7100.2-1, indicate all leaks repaired, eliminated, or scheduled for repair during the reporting year, including those incidents reported on Form RSPA F 7100.2.

PART E

Include all known leaks scheduled for elimination by repair or by replacement of the pipe or other component.

PART F

"Preparer" is the name of the person most knowledgeable about the information submitted in the report or the person to be contacted for additional information.

"Authorized Signature" may be the "preparer" or an officer or other person whom the operator had designated to review and sign reports of this nature.

Amendments Table to 49 CFR 192

This table contains effective dates, codes affected or added, and a summary of amendments, additions or deletions to 49 CFR 192 through December 31, 1984.

Amendments to 49 CFR 192	Effective Dates	Code(s) Affected	Purpose of Amendments
192.1	01/01/71	**Added:** 192.19	**Required the filing of Inspection and Maintenance Plans** by Natural Gas Operators.
192.2	11/12/70	**Extension:** 192.625	To keep **interim safety standards for odorization** in effect until the publication of Federal Minimum Standards.
192.3	11/12/70	**Amended:** 192.55, 192.63, 192.145, 192.153, 192.191, 192.197, 192.199, 192.309, 192.359, 192.371, 192.619.	**Modified provisions** of the new Federal Standards to avoid problems that would have caused unnecessary burdens for the pipeline industry.
192.4	07/30/71	**Added:** Subpart I	Requirements for **Corrosion Control.**
192.5	09/10/71	**Extension:** 192.607	**Extension** of time to establish MAOP.
192.6	12/28/71	**Extension:** 192.625	Same as 192.2
192.7	08/29/72	**Extension:** 192.625	Same as 192.2 and 192.6
192.8	09/27/72	**Amended:** 192.727 **Added:** 192.379	**Deactivation of Service Lines.** Requires that certain steps be taken to prevent the unauthorized introduction of gas into inactive pipeline facilities.
192.9	11/04/72	**Amended:** 192.201(a)	**Modification of Pressure Relief Limitations.** Changes the restriction on accidental pressure buildup in pipelines, other than low pressure distribution systems, which have a maximum allowable operating pressure (MAOP) of less than 60 psig.
192.10	11/13/72	**Added:** 192.12	Creates federal safety standards for **liquefied natural gas.**
192.11	11/14/72	**Amended:** 192.717(b)	Permits the **permanent field repair of pipeline leaks by means other than welded repair sleeves** when the transmission line involved operates at less than 40% of SMYS.

Amendments to 49 CFR 192	Effective Dates	Code(s) Affected	Purpose of Amendments
192.12	03/22/73	**Amended:** 192.55(a)(2) and (b)(2), 192.65, Appendix A, Section I and II, Appendix B, Section I **Added:** Section III, Appendix B	To provide greater **flexibility in qualifying pipe.**
192.13	05/10/73	**Amended:** 192.3	Broadens **definition** of **"service line."**
192.14	06/01/73	**Extension:** 192.625	Extends **interim odorization requirements** - same as Amendments 2, 6 and 7.
192.15	01/01/74	**Extension:** 192.625	Extends **interim odorization requirements** - same as Amendments 2, 6, 7 and 14.
192.16	01/01/75	**Extension:** 192.625	Extends **interim odorization requirements** - same as Amendments 2, 6, 7, 14 and 15.
192.17	02/02/75	**Amended:** 192.65(a) **Amended:** Appendix A.II.4.	**Incorporates by reference API 1972 edition API RP5L1 entitled API Recommended Practice for Railroad Transportation of Line Pipe.**
192.18	03/20/75	**Amended:** 192.225(a), 192.227(a) (2), 192.229(c), 192.241(c), Appendix A, Item II.A.8.	Improve **quality of welding performed on gas and liquid lines.** Incorporates by reference 13th edition of API Standard 1104 - Welding Standards.
192.19	03/21/75	**Amended:** 192.59(a)(1)(B)(1), Adds (c)	**Qualification for Use of Plastic Pipe.** Incorporates by reference 1970 and 1971 editions of ASTM special sizes of plastic pipe where pipe of a diameter included in a listed specification is impractical to use; and qualifies plastic pipe manufactured after March 21, 1975, for use only if it is manufactured in accordance with the latest edition of a listed specification.
192.20	04/21/75	**Amended:** 192.707	**Line Markers for Mains and Transmission Lines.** Revises the existing 192.707 for marking the location of gas transmission lines and establishes new

Amendments to 49 CFR 192	Effective Dates	Code(s) Affected	Purpose of Amendments
			marking requirements for gas distribution mains under that section.
192.21	06/04/75	**Amended:** 192.65 (a)(b) **Added:** 192.706	**Odorization of Gas in Transmission Lines.** Establishes minimum federal safety standards for odorization of gas in transmission lines. Modifies 192.705 and adds 192.706 to require patrolling and leak surveys on the basis of transmission lines in certain class locations and whether lines carry odorized gas.
192.22	07/01/75	**Amended:** 192.227(a)(2)(i), 192.229(c)(1)' 192.241(c)	Modifies federal regulations in 192.241(c) and 195.228 to permit the use of **API 1104, section 6.9 covering the depth of undercutting adjacent to a weld root bead to be used** in determining the acceptability of that undercutting on gas and liquid lines.
192.23	06/01/76	**Amended:** 192.755	**Protecting Cast Iron Pipelines.** Requires operator to provide protection against the potential for damage which arises when the support for a buried cast iron pipeline is disturbed, either by the operator or otherwise.
192.24	10/01/76	**Added:** 192.615	**Requires emergency plans.**
192.25	07/04/76	**Amended:** 192.753(a)	**Caulked Bell and Spigot Joints.** Establishes performance standards for the use of other sealing methods and materials that provide a level of safety at least equal to that provided by mechanical leak clamps in sealing cast iron bell and spigot joints. The performance standards are (1) flexibility in the joint, (2) permanent chemical or mechanical bonding of the sealant with the pipe, and (3) compliance with the strength, environmental, and chemical compatibility requirements of 192.53 and 192.143.
192.26	07/01/76	**Amended:** 192.313	Modifies to provide more appropriate safety requirements for **steel pipe which is subjected to field bending.**
192.27	11/01/76 08/01/77	**Amended:** 192.1, 192.3, 192.5,	**Modifies** many of the **design, construction, testing, operation, and mainte-**

Amendments to 49 CFR 192	Effective Dates	Code(s) Affected	Purpose of Amendments
		192.13, 192.111, 192.161, 192.163, 192.167, 192.179, 192.243, 192.245, 192.317, 192.319, 192.327, 192.465, 192.469, 192.481, 192.619, 192.707, 192.713, 192.717, 192.727	**nance regulations** in Part 192 as they relate to **gas pipeline facilities** and the transportation of gas **offshore**, in or affecting interstate commerce. Also, more clearly delineates that applicability of Part 192 to offshore pipelines.
192.27A	10/27/76	**Amended:** 192.619(a)(3) and (c)	To **extend deadlines** for previously unregulated **offshore gathering lines** to comply with .619.
192.20A	12/31/76	**Amended:** 192.707(d)(1) and (e) (2) (1)	Amends the **wording requirements** for **pipeline markers** to reflect name of gas transported.
192.28	08/12/77	**Amended.** 192.455(a) **Added:** 192.455(f)	**Permits** the use of certain **metal fittings** in **plastic pipelines.**
192.29	11/03/77	**Amended:** 192.313(a)(4)	Permits **longitudinal welds in field bends** of **steel pipe** to be placed other than near the neutral axis when an internal bending mandral is used, or when bending pipe of 12" or less in outside diameter to wall thickness ratio of less than 70.
192.30	12/30/77	**Amended:** 192.13(a), **Added:** 192.14, **Added:** 192.452, **Amended:** 192.619(a)(2)(ii)	**Conversion** of existing **pipeline** to **gas** service.
192.31	05/18/78	**Added:** 192.63(b), **Revised:** 192.121, **Revised:** 192.123(a); (b)(1) and (2); (c) and (d).	**Design of Plastic Pipelines.** (1) Increase maximum allowable operating temperature of thermoplastic pipe from 100^0 F to 140^0 F, (2) prohibits the operation of thermoplastic pipe at a temperature higher than its long term hydrostatic test temperature; (3) establishes alternative temperature bases for determining the long term hydrostatic strength of thermoplastic pipe, (4) establishes a single design factor for all plastic pipe, (5) requires that thermoplastic pipe be marked to indicate its

Amendments to 49 CFR 192	Effective Dates	Code(s) Affected	Purpose of Amendments
			long term hydrostatic strength and related temperature basis. Provides for use of properly designated thermoplastic service risers enclosed in metallic casings.
192.31A	05/16/78	**Amended:** 192.63(b)	**Postpones effective date** of the **marking requirements** of 192.63(b).
192.32	06/01/78	Appendix A, Section II Appendix B, Section I	**Updates incorporation** by **reference** of API Standards 5LS, API Specification for spiral weld line pipe and API Standard 5LX, API Specification for high-test line pipe to include in Part 192, the March 1976 supplement and the 1977 edition of each document.
192.33	09/05/78	192.451 (Deleted Paragraph b) 192.457 (Amended a,b) 192.465 (Amended b,c) 192.467 (Amended b) 192.473 (Amended a) 192.475 (Amended a) 192.477 Amended 192.479 Amended 192.481 Amended 192.458(a) Amended 192.491(a) Amended	Makes miscellaneous **changes** to **MTB's corrosion control requirements** for natural gas and other gas pipelines.
192.31	09/25/78	**Amended:** 192.121	**Corrects misprint** in formula.
192.34	01/01/80	**Amended:** 192.281, **Added:** 192.283, **Added:** 192.285, **Added:** 192.287	**Established tests** for **qualifying procedures** and **personnel** to make all **types of joints in plastic pipelines** used in the transportation of natural and other gases.
192.34	07/01/80	**Extension:** 192.281, 192.283, 192.285, 192.287	**Extends effective date** of .281, .283, .285, and .287.
192.34A	07/01/80	**Amended:** 192.283 192.285	Changes requirements under .283, and .285. Most significant changes were: (1) **permits** the **use** of any **force** on a **specimen lateral joint** that **initiates failure;** (2) **permits tensile testing** at ambient temperature and humidity; (3) more clearly **define** the **criteria** for **test specimen** acceptable or **failure;** (4) **permits joining of pipe and fittings**

Amendments to 49 CFR 192	Effective Dates	Code(s) Affected	Purpose of Amendments
			manufactured before July 1, 1980, in accordance with existing procedures without requalifying those procedures; (5) **permits alternative test methods** for **qualifying persons to make heat fusion, solvent cement or adhesive joints;** and (6) **redefines and limits** the **conditions** under which a **person** must **requalify to make plastic pipe joints.**
192.34B	01/02/81	**Amended:** 192.281, 192.283, 192.285, 192.287	**Permits a burst test** in accordance with Paragraph 8.5 or 8.9 of ASTM D 2517 **in qualifying joining procedures for thermosetting plastic pipe.** The rules for qualifying joining personnel are clarified by permitting any one of three tests required to qualify a specific joining procedure to be used to qualify persons to make joints under that procedure.
192.35	12/20/79	**Amended:** 192.465(a)	**Establishes monitoring requirements** for testing short sections of transmission pipelines on a sampling basis to determine the effectiveness of cathodic protection in controlling corrosion.
192.35A	04/07/80	**Amended:** 192.465	**Reinstates requirement for testing cathodic protection** in controlling corrosion.
192.36	03/15/80 07/23/80 11/24/80 01/01/82	**Deleted:** 192.12	Removes **192.12 governing LNG facilities** from Part 192 and establishes regulations under 193.
192.37	03/04/81	**Amended:** 192.7(b), (c), 192.113, 192.117, 192.145(a), 192.163(e), 192.225(a) & (b)(1) & (2), 192.227(a), & (b)(1) & (2), 192.229(c), 192.237(a), 192.239(a)(b), 192.241(c) 192.557(d)(1)(d)(3)	**Updates existing references** to industry prepared documents to later published editions.
192.38	07/20/81	**Deleted:** 192.17	Removed 192.17 from Subpart A and the Table of Contents.
192.39	04/07/82	**Deleted:** 192.455(f)(3)	**Removes** the **requirements** that a means for **identification** be provided for

Amendments to 49 CFR 192	Effective Dates	Code(s) Affected	Purpose of Amendments
			each **metal alloy fitting** that is **installed without coating** and cathodic protection in plastic pipelines.
192.40	04/01/83	**Added:** 192.614	**Requires** operators to participate in **one call system.**
192.34	07/29/82	**Amended:** 192.283(b)(5)	**Amends units of measurement** contained in safety standards relating **to joining plastic pipe and to LNG facilities.**
192.41	10/20/82	**Amended:** Appendices A & B	**Updates incorporation by reference** from 1978 to 1981 edition of the industry specifications for thermoplastic pipe.
192.42	10/07/82	**Amended:** Appendix A	**Address change for NFPA.**
192.43	11/22/82	**Amended:** 192.227, 192.705, 192.706, 192.721, 192.723, 192.731, 192.739, 192.743, 192.745	**Restates the intervals** in which **periodic inspections, tests,** and **other activities must be conducted.**
192.34	11/04/82	**Amended:** 192.283(b)(5)	Corrected by removing **38°C** and adding in its place **55°C.**
192.44	07/06/83	**Amended:** 192.707(a)(b)(d) Removed (e)(f)	**Revokes** requirement for **line markers** at **pipeline crossings** at **navigable waterways.**
192.45	08/04/83	**Added:** 192.144	**Establishes criteria** to qualify for **use or reuse,** in **gas** or **hazardous pipelines.**
192.46	11/21/83	**Amended:** 192.245	**Modifies present regulations** on the **repair or removal of defective girth welds** utilizing performance standards for weld repair.
192.47	04/02/84	**Amended:** 192.105	**Temperature Limits On Steel Pipe.** Increases temperature limit to which steel pipe that has been cold expanded to meet the SMYS may be heated without a reduction in design pressure.
192.48	06/11/84	**Amended:** 192.143	**Revises existing requirements** for **design of components** to allow designs based upon a pressure rating which is established by the manufacturer as a result of pressure testing.

Part 192--Transportation of Natural and Other Gas by Pipeline: Minimum Safety Standards

Subpart A--General

Sec.

Subpart B--Materials

Subpart C--Pipe Design

Subpart D--Design of Pipeline Components

Subpart E--Welding of Steel in Pipelines

Subpart F--Joining of Materials Other Than by Welding

Subpart G--General Construction Requirements for Transmission Lines and Mains

Subpart H--Customer Meters, Service Regulators, and Service Lines

Subpart I--Requirements for Corrosion Control

Subpart J--Test Requirements

Subpart K--Uprating

Subpart L--Operations

Subpart M--Maintenance

Part 192--Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards

Subpart A--General

192.1 **SCOPE OF PART.**

(a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act. *(43 U.S.C. 1331)*

(b) This part does not apply to--

(1) Offshore gathering of gas upstream from the outlet flange of each facility on the outer continental shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream; and

(2) Onshore gathering of gas outside of the following areas:

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

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

192.3 **DEFINITIONS.**

As used in this part--

Distribution Line means a pipeline other than a gathering or transmission line.

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

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

High pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Listed specification means a specification listed in section I of Appendix B of this part.

Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main means a distribution line that serves as a common source of supply for more than one service line.

Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum allowable operating pressure means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Municipality means a city, county, or any other political subdivision of a State.

Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

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

Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

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

Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

Pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

Secretary means the Secretary of Transportation or any person to whom he has delegated authority in the matter concerned.

Service line means a distribution line that transports gas from a common source of supply to (1) a customer meter or the connection to a customer's piping, whichever is farther downstream, or (2) 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.

Short section of pipeline means a segment of a pipeline 100 feet or less in length.

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 192.107(b).

State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

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 or storage facility;

(b) Operates at a hoop stress of 20 percent or more of SMYS; or

(c) Transports gas within a storage field.

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.

192.5 **CLASS LOCATIONS.**

(a) Offshore is Class 1 location. The Class location onshore is determined by applying the criteria set forth in this section: The class location unit is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Except as provided in paragraphs (d)(2) and (f) of this section, the class location is determined by the buildings in the class location unit. For the purposes of this section, each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

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

(c) A Class 2 location is any class location unit that has more than 10 but less than 46 buildings intended for human occupancy.

(d) A Class 3 location is:

(1) Any class location unit that has 46 or more buildings intended for human occupancy; or

(2) An area where the pipeline lies within 100 yards of any of the following:

(i) A building that is occupied by 20 or more persons during normal use.

(ii) A small, well-defined outside area that is occupied by 20 or more persons during normal use, such as a playground, recreation area,

outdoor theater, or other place of public assembly.

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

(f) The boundaries of the class locations determined in accordance with paragraphs (a) through (e) of this section may be adjusted as follows:

(1) A Class 4 location ends 220 yards from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 3 location, the Class 3 location ends 220 yards from the nearest building in the cluster.

(3) When a cluster of buildings intended for human occupancy requires a Class 2 location, the Class 2 location ends 220 yards from the nearest building in the cluster.

192.7 INCORPORATION BY REFERENCE.

(a) Any documents or parts thereof incorporated by reference in this part are a part of this regulation as though set out in full.

(b) All incorporated documents are available for inspection in the Materials Transportation Bureau, Washington. D.C., and at the Office of the Federal Register, 1100 L Street, N.W., Washington, D.C. These materials have been approved for incorporation by reference by the Director of the Federal Register. In addition, the documents are available at the addresses provided in Appendix A to this part.

(c) The full titles for the publications incorporated by reference in this part are provided in Appendix A to this part. Numbers in parentheses indicate applicable editions. Earlier editions of documents 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 for a listing of the earlier listed editions.
(Amdt. 192.37, effective March 4, 1981)

192.9 GATHERING LINES.

Each gathering line must comply with the requirements of this part applicable to transmission lines.

192.11 PETROLEUM GAS SYSTEMS.

(a) No operator may transport petroleum gas in a system that serves 10 or more customers, or in a system, any portion of which is located in a public place (such as a highway), unless that system meets the requirements of this part and of NFPA Standards No. 58 and No. 59. In the event of a conflict, the requirements of this part prevail.

(b) Each petroleum gas system covered by paragraph (a) of this section must comply with the following:

(1) Above-ground structures must have open vents near the floor level.

(2) Below-ground structures must have forced ventilation that will prevent any accumulation of gas.

(3) Relief valve discharge vents must be located so as to prevent any accumulation of gas at or below ground level.

(4) Special precautions must be taken to provide adequate ventilation where excavations are made to repair an underground system.

(c) For the purpose of this section, petroleum gas means propane, butane, or mixtures of these gases, other than a gas air mixture that is used to supplement supplies in a natural gas distribution system.

192.12 LIQUEFIED NATURAL GAS FACILITIES. (REVOKED)

(Section 192.12 is revoked in the text of the rules and the table of sections.)

(Amdts. 192-36, effective March 15, 1980)

192.13 GENERAL.

(a) No person may operate a segment of pipeline that is readied for service after March 12, 1971, or in the case of an offshore gathering line, after July 31, 1977, unless--

(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or

(2) The pipeline qualifies for use under this part in accordance with paragraph 192.14.

(b) No person may operate a segment of pipeline that is replaced, relocated, or otherwise changed after November 12, 1970, or in the case of an offshore gathering line, after July 31, 1977, unless that replacement, relocation, or change has been made in accordance with this part.

(c) Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part.

192.14 CONVERSION TO SERVICE SUBJECT TO THIS PART.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

(1) 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.

(2) The pipeline right-of-way, all above-ground 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.

(3) All known unsafe defects and conditions must be corrected in accordance with this part.

(4) The pipeline must be tested in accordance with Subpart J of this part to substantiate the maximum allowable operating pressure permitted by Subpart L of this part.

(b) 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 (a) of this section.

192.15 RULES OF REGULATORY CONSTRUCTION.

(a) As used in this part:

Includes means including but not limited to.

May means *is permitted to* or *is authorized to.*

May not means *is not permitted to* or *is not authorized to.*

Shall is used in the mandatory and imperative sense.

(b) In this part:

(1) Words importing the singular include the plural; (2) Words importing the plural include the singular; and (3) Words importing the masculine gender include the feminine.

192.17 FILING OF INSPECTION AND MAINTENANCE PLAN (DELETED)

(Amndts. 192-38, effective July 20, 1981)

Subpart B--Materials

192.51 SCOPE.

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

192.53 GENERAL.

Materials for pipe and components must be:

(a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;

(b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and

(c) Qualified in accordance with the applicable requirements of this subpart.

192.55 STEEL PIPE.

(a) New steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification;

(2) It meets the requirements of--

(i) Section II of Appendix B to this part; or

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

(3) It is used in accordance with paragraph (c) or (d) of this section.

(b) Used steel pipe is qualified for use under this part if:

(1) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of Appendix B to this part;

(2) It meets the requirements of--

(i) Section II of Appendix B to this part; or

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

(3) 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 part; or

(4) It is used in accordance with paragraph (c) of this section.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 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 part.

(d) 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.

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Standard 5LX.

192.57 CAST IRON OR DUCTILE IRON PIPE.

(a) New cast iron or new ductile iron pipe is qualified for use under this part if it has been manufactured in accordance with a listed specification.

(b) Used cast iron or used ductile iron pipe is qualified for use under this part if inspection shows that the pipe is sound and allows the makeup of tight joints and:

(1) It has been removed from an existing pipeline that operated at the same or higher pressure; or

(2) It was manufactured in

accordance with a listed specification.

192.59 **PLASTIC PIPE.**

(a) New plastic pipe is qualified for use under this part if:

(1) When the pipe is manufactured, it is manufactured in accordance with the latest listed edition of a listed specification, except that before March 21, 1975, it may be manufactured in accordance with any listed edition of a listed specification; and

(2) It is resistant to chemicals with which contact may be anticipated.

(b) Used plastic pipe is qualified for use under this part if:

(1) When the pipe was manufactured, it was manufactured in accordance with the latest listed edition of a listed specification, except that pipe manufactured before March 21, 1975, need only have met the requirements of any listed edition of a listed specification;

(2) It is resistant to chemicals with which contact may be anticipated.

(3) It has been used only in natural gas service;

(4) Its dimensions are still within the tolerances of the specification to which it was manufactured; and

(5) It is free of visible defects.

(c) For the purpose of paragraphs (a)(1) and (b)(1) of this section, 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:

(1) Meets the strength and design criteria required of pipe included in that listed specification; and

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

192.61 **COPPER PIPE.**

Copper pipe is qualified for use under this part if it has been manufactured in accordance with a listed specification.

192.63 **MARKING OF MATERIALS.**

(a) Except as provided in paragraph (e) of this section, each valve, fitting, length of pipe, and other component must be marked as prescribed in:

(1) The specification or standard to which it was manufactured; or

(2) MSS Standard Practice, SP-25.

(b) In addition to the requirements in paragraph (a), thermoplastic pipe manufactured in accordance with the 1974a or earlier listed edition of ASTM D2513 must be marked as required by section 9.2 of ASTM D2513 (1975b edition) unless the pipe was manufactured before May 18, 1978, and is installed where operating temperatures are not above 38 C (100 F).

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

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

(e) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

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

192.65 **TRANSPORTATION OF PIPE.**

In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless--

(a) The transportation is performed in accordance with the 1972 edition of API RP5L1, except that before February 25, 1975, the transportation may be performed in accordance with the 1967 edition of API RP5L1.

(b) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with Subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 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 Subpart J of this part, the test pressure must be maintained for at least 8 hours.

Subpart C--Pipe Design

192.101 SCOPE.

This subpart prescribes the minimum requirements for the design of pipe.

192.103 GENERAL.

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.

192.105 DESIGN FORMULA FOR STEEL PIPE.

(a) The design pressure for steel pipe is determined in accordance with the following formula:

$$P = \frac{2\,St}{D} \times F \times E \times T$$

P — Design pressure in pounds per square inch gage.
S — Yield strength in pounds per square inch determined in accordance with 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 192.109. Additional wall thickness required for concurrent external loads in accordance with 192.103 may not be included in computing design pressure.
F — Design factor determined in accordance with 192.111.
E — Longitudinal joint factor determined in accordance with 192.113.
T — Temperature derating factor determined in accordance with 192.115.

(b) 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 the welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900° F [482° C] at any time or is held above 600° F [316° C] for more than 1 hour.
(Amendments 192-47 effective April 2, 1984)

192.107 YIELD STRENGTH (S) FOR STEEL PIPE

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

(b) For pipe that is manufactured in accordance with a specification not listed in section I of Appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in 192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of Appendix B to this part, the lower of the following:

(i) 80 percent of the average

yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests, but not more than 52,000 p.s.i.

(2) If the pipe is not tensile tested as provided in subparagraph (1) of this paragraph, 24,000 p.s.i.

192.109 **NOMINAL WALL THICKNESS (t) FOR STEEL PIPE.**

(a) 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.

(b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gage set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in 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 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

192.111 **DESIGN FACTOR (F) FOR STEEL PIPE**

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in 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

(b) A design factor of 0.60 or less must be used in the design formula in 192.105 for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;

(2) 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;

(3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

(4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five 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.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in 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.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in 192.105 for--

(1) Steel pipe in a compressor station, regulating station, or measuring station; and

(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

192.113 **LONGITUDINAL JOINT FACTOR (E) FOR STEEL PIPE.**

The longitudinal joint factor to be used in the design formula in 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	.60
ASTM A 106	Seamless	1.00
ASTM A 134	Electric fusion arc welded	.80
ASTM A 135	Electric resistance welded	1.00
ASTM A 139	Electric fusion arc welded	.80
ASTM A 211	Spiral welded steel pipe	.80
ASTM A 333	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 5 L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
API 5 LX	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
API 5 LS	Electric resistance welded	1.00
	Submerged arc welded	1.00
Other	Pipe over 4 inches	.80
Other	Pipe 4 inches or less	.60

(Amdt. 192-37, Table Revised, effective March 31, 1981)

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

192.115 TEMPERATURE DERATING FACTOR (T) FOR STEEL PIPE.

The temperature derating factor to be used in the design formula in 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.

192.117 DESIGN OF CAST IRON PIPE.

Cast iron pipe must be designed in accordance with ANSI C101-67.

192.119 DESIGN OF DUCTILE IRON PIPE.

(a) Ductile iron pipe must be designed in accordance with ANSI A 21.50 using the following values in the design equations:

s (design hoop stress) 16,800 p.s.i.
f (design bending stress) 36,000 p.s.i.

(b) Ductile iron pipe must be grade (60-42-10) and must conform to the requirements of ANSI A 21.52.

192.121 DESIGN OF PLASTIC PIPE.

The design pressure for plastic pipe is determined in accordance with the following formula, subject to the limitation of 192.123.

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

P — Design pressure, gage, kPa (psi).

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); for reinforced thermosetting plastic pipe, 75,800 kPa (11,000 psi).

t — Specified wall thickness, mm (in.).

D — Specified outside diameter, mm (in.).

192.123 DESIGN LIMITATIONS FOR PLASTIC PIPE.

(a) The design pressure may not exceed a gage pressure of 689 kPa (100 p.s.i.g.) for plastic pipe used in--

(1) Distribution systems; or

(2) Class 3 and 4 locations.

(b) Plastic pipe may not be used where operating temperatures of the pipe will be:

(1) Below minus 29°C (-20°F); or

(2) In the case of thermoplastic pipe, above the temperature at which the long-term hydrostatic strength used in the design formula under 192.121 is determined, except that pipe manufactured before May 18, 1978, may be used at temperatures up to 38°C (100°F); or in the case of reinforced thermosetting plastic pipe, above 66°C (150°F).

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

(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

Nominal Size in inches	*Minimum wall thickness in mm/inches*
2	1.52 (0.060)
3	1.52 (0.060)
4	1.78 (0.070)
6	2.54 (0.100)

192.125 **DESIGN OF COPPER PIPE.**

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches and must be hard drawn.

(b) Copper pipe used in service lines must have a minimum wall thickness as specified for type "L" pipe in ASTM B 88.

(c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i.g.

(d) 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 100 standard cubic feet of gas.

Subpart D--Design of Pipeline Components

192.141 **SCOPE.**

This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

192.143 **GENERAL REQUIREMENTS.**

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.

(Amndt. 192-48 effective June 11, 1984)

192.144 **QUALIFYING METALLIC COMPONENTS**

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in Appendix A of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if--

(a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength of the component; and

(b) 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 listed in Appendix A:

(1) Pressure testing;

(2) Materials; and

(3) Pressure and temperature ratings.

192.145 **VALVES.**

(a) Each valve must meet the minimum requirements, or the equivalent, of API6A, API6D, MSS SP-70, MSS SP-71, or MSS SP-78. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those standards.

(b) Each valve must be able to meet the anticipated operating conditions.

(c) No valve having shell components made of ductile iron may be used at pressures exceeding 80 percent 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 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if:

(1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i.g.; and

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

(d) No valve having pressure containing parts made of ductile iron may be used in the gas pipe components of compressor stations.
(Amdt. 192-37 effective March 31, 1981)

192.147 **FLANGES AND FLANGE ACCESSOIRES.**

(a) General requirements. Each flange or flange accessory must meet the minimum requirements of ANSI B16.5, MSS SP-44, or ANSI B16.24, or the equivalent.

(b) 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.

192.149 **STANDARD FITTINGS.**

(a) 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 part, or their equivalent.

(b) 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.

192.151 **TAPPING.**

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

(b) 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.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more than 25 percent of the nominal diameter of the pipe unless the pipe is reinforced, except that:

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

(2) A 1 1/4-inch tap may be made in a 4-inch cast iron or ductile iron pipe, without reinforcement. 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 6-inch or larger pipe.

192.153 **COMPONENTS FABRICATED BY WELDING.**

(a) 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 of the ASME Boiler and Pressure Vessel Code.

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with the ASME Boiler and Pressure Vessel Code, except for the following:

(1) Regularly manufactured butt-welding fittings.

(2) Pipe that has been produced and tested under a specification listed in Appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) 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.

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

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Vessel Code, flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i.g., or more, or is more than 3 inches nominal diameter.

192.155 **WELDED BRANCH CONNECTIONS.**

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.

192.157 **EXTRUDED OUTLETS.**

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.

192.159 **FLEXIBILITY.**

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.

192.161 **SUPPORTS AND ANCHORS.**

(a) Each pipeline and its associated equipment must have enough anchors or supports to:

(1) Prevent undue strain on connected equipment;

(2) Resist longitudinal forces caused by a bend or offset in the pipe; and

(3) Prevent or damp out excessive vibration.

(b) 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.

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

(1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.

(2) Provision must be made for the service conditions involved.

(3) Movement of the pipeline may not cause disengagement of the support equipment.

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

(1) A structural support may not be welded directly to the pipe.

(2) The support must be provided by a member that completely encircles the pipe.

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

(e) 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.

(f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent lateral and vertical movement.

192.163 COMPRESSOR STATIONS: DESIGN AND CONSTRUCTION.

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

(b) Building construction. Each building on a compressor station site must be made of noncombustible materials if it contains either:

(1) Pipe more than 2 inches in diameter that is carrying gas under pressure; or

(2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) Exits. Each operating floor of a main compressor building must have at least two 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.

(d) Fenced areas. Each fence around a compressor station must have at least two 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 200 feet of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

(e) Electrical facilities. Electrical equipment and wiring installed in compressor stations must conform to the National Electrical Code, so far as that code is applicable.

NFPA-70 (ANSI) (Amdt. 192-37, effective March 4, 1981)

192.165 COMPRESSOR STATIONS: LIQUID REMOVAL.

(a) Where entrained vapors in gas may liquefy under the anticipated pressure

and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.

(b) Each liquid separator used to remove entrained liquids at a compressor station must:

(1) Have a manually operable means of removing these liquids.

(2) 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

(3) 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.

192.167 **COMPRESSOR STATIONS: EMERGENCY SHUTDOWN.**

(a) Except for unattended field compressor stations of 1,000 horsepower or less, each compressor station must have an emergency shutdown system that meets the following:

(1) It must be able to block gas out of the station and blow down the station piping.

(2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.

(3) 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.

(4) It must be operable from at least two 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 500 feet from the limits of the station.

(b) 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.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station--

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

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

(2) 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 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c) (2) (ii) of this section, an electrical facility which conforms to Class 1, Group D of the National Electrical Code is not a source of ignition.

192.169 COMPRESSOR STATIONS: PRESSURE LIMITING DEVICES.

(a) 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 10 percent.

(b) 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.

192.171 COMPRESSOR STATIONS: ADDITIONAL SAFETY EQUIPMENT.

(a) 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.

(b) 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.

(c) 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.

(d) 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.

(e) 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.

192.173 COMPRESSOR STATIONS: VENTILATION.

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.

192.175 PIPE-TYPE AND BOTTLE-TYPE HOLDERS.

(a) 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.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

$$C = \frac{3 D \times P \times F}{1{,}000}$$

in which:

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, p.s.i.g.
F—Design factor as set forth in 192.111 of this part.

192.177 ADDITIONAL PROVISIONS FOR BOTTLE-TYPE HOLDERS.

(a) Each bottle-type holder must be:

(1) Located on a storage 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 1,000 p.s.i.g.	25
1,000 p.s.i.g. or more	100

(2) Designed using the design factors set forth in 192.111; and

(3) Buried with a minimum cover in accordance with 192.327.

(b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:

(1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in either API Standard 5A or ASTM A 372.

(2) The actual yield-tensile ratio of the steel may not exceed 0.85.

(3) 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.

(4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(5) The holder, connection pipe, and components must be leak tested after installation as required by Subpart J of this part.

192.179 **TRANSMISSION LINE VALVES.**

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows:

(1) Each point on the pipeline in a Class 4 location must be within 2 1/2 miles of a valve.

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

(3) Each point on the pipeline in a Class 2 location must be within 7 1/2 miles of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles of a valve.

(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following:

(1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage.

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

(c) Each section of a transmission line other than offshore segments 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.

(d) Offshore segments of transmission lines must be equipped with valves or other components to shut off the flow of gas to an offshore platform in an emergency.

192.181 **DISTRIBUTION LINE VALVES.**

(a) 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.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

(3) 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.

192.183 **VAULTS: STRUCTURAL DESIGN REQUIREMENTS.**

(a) 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.

(b) 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.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inches, and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gasses or liquids through the opening and to avert strains in the pipe.

192.185 **VAULTS; ACCESSIBILITY.**

Each vault must be located in an accessible location and, so far as practical, away from:

(a) Street intersections or points where traffic is heavy or dense;

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

(c) Water, electric, steam, or other facilities.

192.187 **VAULTS: SEALING, VENTING, AND VENTILATION.**

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:

(a) When the internal volume exceeds 200 cubic feet:

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches in diameter;

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(b) When the internal volume is more than 75 cubic feet but less than 200 cubic feet:

(1) 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;

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

(3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

(c) If a vault or pit covered by paragraph (b) of this section 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 20 to 1, no additional ventilation is required.

192.189 VAULTS: DRAINAGE AND WATERPROOFING.

(a) Each vault must be designed so as to minimize the entrance of water.

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

(c) All electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, ANSI Standard C1.

192.191 DESIGN PRESSURE OF PLASTIC FITTINGS.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517.

(b) The design pressure of acrylonitrile-butadiene-styrene (ABS) and polyvinyl chloride (PVC) Schedule 40 and 80 thermoplastic fittings must be obtained from the following table:

Design Pressure of Thermoplastic Fittings, P.S.I.G. of Various Strengths, Materials and Class Locations

Size inches	Schedule	ABS Type I and PVC Type II class location 1	2 and 3	4	PVC Type I class location 1	2 and 3	4
1/2	40	100	100	100	100	100	100
	80	100	100	100	100	100	100
3/4	40	100	100	96	100	100	100
	80	100	100	100	100	100	100
1	40	100	100	90	100	100	100
	80	100	100	100	100	100	100
1 1/4	40	100	92	74	100	100	100
	80	100	100	100	100	100	100
1 1/2	40	100	83	66	100	100	100
	80	100	100	94	100	100	100
2	40	89	69	55	100	100	100
	80	100	100	81	100	100	100
2 1/2	40	99	76	61	100	100	100
	80	100	100	85	100	100	100
3	40	84	66	53	100	100	100
	80	100	94	75	100	100	100
3 1/2	40	77	60	48	100	100	96
	80	100	86	69	100	100	100
4	40	71	56	44	100	100	89
	80	100	81	65	100	100	100
5	40	62	49	39	100	97	78
	80	93	72	58	100	100	100
6	40	56	44	35	100	88	71
	80	89	70	56	100	100	100

NOTE: The preceding pressure ratings are the same value as the design pressure of the corresponding pipe size and schedule in the same class location, as determined by the formula given in Section 192.121 and the limitations in Section 192.123 of this part.

192.193 VALVE INSTALLATION IN PLASTIC PIPE.

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.

192.195 PROTECTION AGAINST ACCIDENTAL OVERPRESSURING.

(a) General requirements. Except as provided in 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 192.199 and 192.201.

(b) Additional requirements for distribution 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:

(1) 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

(2) Be designed so as to prevent accidental overpressuring.

192.197 CONTROL OF THE PRESSURE OF GAS DELIVERED FROM HIGH PRESSURE DISTRIBUTION SYSTEMS.

(a) If the maximum actual operating pressure of the distribution system is under 60 p.s.i.g., and a service regulator having the following characteristics is used, no other pressure limiting device is required:

(1) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

(3) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.

(4) Pipe connections to the regulator not exceeding 2 inches in diameter.

(5) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(6) A self-contained service regulator with no external static or control lines.

(b) If the maximum actual operating pressure of the distribution system is 60 p.s.i.g., or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i.g., one 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 having the characteristics listed in paragraph (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 p.s.i.g. 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 60 p.s.i.g., 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, if the pressure on the inlet of the service regulator exceeds the set pressure (60 p.s.i.g., or less), and remains closed until manually reset.

(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.

(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 125 p.s.i.g. For higher inlet pressures, the methods in subparagraph (1) or (2) of this paragraph must be used.

(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.

192.199 REQUIREMENTS FOR DESIGN OF PRESSURE RELIEF AND LIMITING DEVICES.

Except for rupture discs, each pressure relief or pressure limiting device must:

(a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;

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

(c) 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;

(d) Have support made of noncombustible material

(e) 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;

(f) 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;

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

(h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

192.201 REQUIRED CAPACITY OF PRESSURE RELIEVING AND LIMITING STATIONS.

(a) 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:

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

(2) In pipelines other than a low pressure distribution system:

(i) If the maximum allowable operating pressure is 60 p.s.i.g., or more, the pressure

may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

(ii) If the maximum allowable operating pressure is 12 p.s.i.g., or more, but less than 60 p.s.i.g., the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i.g.; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i.g., the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

(b) When more than one 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.

(c) 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.

192.203 INSTRUMENT, CONTROL, AND SAMPLING PIPE AND COMPONENTS.

(a) Applicability. This section 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.

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

(1) 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.

(2) 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.

(3) Brass or copper material may not be used for metal temperatures greater than 400°F.

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

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

(7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses.

(8) 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.

(9) Each control line must be

protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.

Subpart E--Welding of Steel in Pipelines

192.221 **SCOPE.**

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.

(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

192.223 **GENERAL.**

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

(b) Welding must be performed by welders who are qualified under 192.227 and 192.229 for the welding procedure to be used.

192.225 **QUALIFICATION OF WELDING PROCEDURES.**

(a) 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 may continue to be used but may not be requalified under the earlier edition.

(b) When a welding procedure is being qualified under Section IX of the ASME Boiler and Pressure Vessel Code, the following steels are considered to fall within the P-Number 1 grouping for the purpose of the essential variables and do not require separate qualification of welding procedures:

(1) Carbon steels that have a carbon content of 0.32 percent (heat analysis) or less.

(2) Carbon steels that have a carbon equivalent (C+1/4Mn) of 0.65 percent (heat analysis) or less.

(3) Alloy steels with weldability characteristics that have been shown to be similar to the carbon steels listed in subparagraphs (1) and (2) of this paragraph. Alloy steels and carbon steels that are not covered by subparagraph (1), (2), or (3) of this paragraph require separate qualification of procedures for each individual pipe specification in accordance with sections VIII and IX of the ASME Boiler and Pressure Vessel Code.

(c) Each welding procedure must be recorded in detail during the qualifying tests. This record must be retained and followed whenever the procedure is used. *(Revised, Amdt. 192-37, effective March 4, 1981)*

192.227 **QUALIFICATION OF WELDERS.**

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

(b) When a welder is being qualified under section IX of the ASME Boiler and Pressure Vessel Code, the following steels are considered to fall within the P-Number 1 grouping for the purpose of the essential variables and do not require separate qualification:

(1) Carbon steels that have a carbon content of 0.32 percent (heat analysis) or less.

(2) Carbon steels that have a carbon equivalent (C 1/4Mn) of 0.65 percent (heat analysis) or less.

(3) Alloy steels with weldability characteristics that have been shown to be similar to the carbon steels listed in subparagraphs (1) and (2) of this paragraph.

Alloy steels and carbon steels that are not covered by subparagraphs (1), (2), or (3) of this paragraph require separate qualification of welders for each individual pipe specification in accordance with sections VIII and IX of the ASME Boiler and Pressure Vessel Code.

(c) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section 1 of Appendix C to this part. A welder who makes welded service line connections to mains must also perform an acceptable test weld under section I of Appendix C to this part as part of his qualifying test. After initial qualification, a welder may not perform welding unless--

(1) Within the preceding 15 calendar months, the welder has requalified, except that the welder must requalify at least once each year; or

(2) Within the preceding 7½ calendar months, but at least twice each calendar year, the welder has had--

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

(ii) For welders who work only on service lines 2 inches or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix C to this part.

192.229 **LIMITATIONS ON WELDERS.**

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

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

(c) A welder qualified under 192.227(a) may not weld unless within the preceding 6 calendar months the welder has had one 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 may weld but may not requalify under that earlier edition.
(Revised, Amdts. 192-37, effective March 4, 1981)

192.231 **PROTECTION FROM WEATHER.**

The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

192.233 **MITER JOINTS.**

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

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

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

192.235 **PREPARATION FOR WELDING.**

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.

192.237 **PREHEATING.**

(a) Carbon steel that has a carbon content in excess of 0.32 percent (heat analysis) or a carbon equivalent (C+1/4Mn) of 0.65 percent (heat analysis) must be preheated for welding.

(b) Carbon steel that has a lower carbon content or carbon equivalent than the steels covered by paragraph (a) of this section must be preheated for welding when preheating will alleviate existing conditions that would limit the welding technique or tend to adversely affect the quality of the weld.

(c) When steel materials with different preheat temperatures are being preheated for welding, the higher temperature must be used.

(d) Preheat temperature must be monitored to ensure that the required preheat temperature is reached before, and maintained during, the welding operation.

192.239 **STRESS RELIEVING.**

(a) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content in excess of 0.32 percent (heat analysis) or a carbon equivalent (C+1/4Mn) in excess of 0.65 percent (heat analysis) must be stress relieved as prescribed in Section VIII of the ASME Boiler and Pressure Vessel Code.

(b) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content of less than 0.32 percent (heat analysis) or a carbon equivalent (C+1/4Mn) of less than 0.65 percent (heat analysis) must be thermally stress relieved when conditions exist which cool the weld at a rate detrimental to the quality of the weld.

(c) Except as provided in paragraph (f) of this section, each weld on carbon steel pipe with a wall thickness of more than 1 1/4 inches must be stress relieved.

(d) When a weld connects pipe or components that are of different thickness, the wall thickness to be used in determining whether stress relieving is required under this section is:

(1) In the case of pipe connections, the thicker of the two pipes joined; or

(2) In the case of branch connections, slip-on flanges, or socket weld fittings, the thickness of the pipe run or header.

(e) Each weld of different materials must be stress relieved, if either material requires stress relieving under this section.

(f) Notwithstanding paragraphs (a), (b), and (c) of this section, stress relieving is not required for the following:

(1) A fillet or groove weld one-half inch, or less, in size (leg) that attaches a connection 2 inches, or less, in diameter; or

(2) A fillet or groove weld three-eights inch, or less, in groove size that attaches a supporting member or other nonpressure attachment.

(g) Stress relieving required by this section must be performed at a temperature of at least 1,100°F. for carbon steels and at least 1,200°F. for ferritic alloy steels. When stress relieving a weld between steel materials with different stress relieving temperatures, the higher temperature must be used.

(h) When stress relieving, the temperature must be monitored to ensure that a uniform temperature is maintained

and that the proper stress relieving cycle is accomplished.

(Revised a & b, Amdt. 192-37, effective March 4, 1981)

192.241 **INSPECTION AND TEST OF WELDS.**

(a) Visual inspection of welding must be conducted to insure that--

(1) The welding is performed in accordance with the welding procedure; and

(2) The weld is acceptable under paragraph (c) of this section.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with 192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if--

(1) The pipe has a nominal diameter of less than 6 inches; or

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

(c) 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, the standards in subsection 6.9 for depth of undercutting adjacent to the root bead apply only if--

(1) That depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; and

(2) Visual determination of internal undercutting is made in all pipe of the same diameter in a pipeline, except where impractical at tie-in welds.

(Revised Section (c), Amdts. 192-37, effective March 4, 1981)

192.243 **NONDESTRUCTIVE TESTING.**

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

(b) Nondestructive testing of welds must be performed:

(1) In accordance with written procedures; and

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

(c) Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under 192.241(c).

(d) When nondestructive testing is required under 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:

(1) In Class 1 locations, except offshore, at least 10 percent.

(2) In Class 2 locations, at least 15 percent.

(3) In Class 3 and Class 4 locations and at crossings of major or navigable rivers, and offshore, 100 percent if practicable, but not less than 90 percent.

(4) Within railroad or public highway rights-of-way, including tunnels, bridges and overhead road crossings, and at pipeline tie-ins, 100 percent.

(e) 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 nondestructive testing is required under 192.241 (b).

(f) When nondestructive testing is required under 192.241 (b), each operator must retain, for the life of the pipeline, a record showing by mile post, 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.

192.245 **REPAIR OR REMOVAL OF DEFECTS.**

(a) Each weld that is unacceptable under 192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipelay vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to clean metal and the segment to be repaired must be preheated if conditions exist which 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.

Repair of a crack, or any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under 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.

Subpart F--Joining of Materials Other Than by Welding

192.271 **SCOPE.**

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

192.273 **GENERAL.**

(a) 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.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

192.275 **CAST IRON PIPE.**

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

(b) 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.

(c) Cast iron pipe may not be joined by threaded joints.

(d) Cast iron pipe may not be joined by brazing.

(e) Each flange on a flanged joint in cast iron pipe must conform in dimensions and drilling to ANSI Standard B16.1 and be cast integrally with the pipe, valve, or fitting.

192.277 **DUCTILE IRON PIPE.**

(a) Each mechanical joint in ductile iron pipe must conform to ANSI Standard A21.52 and ANSI Standard A21.11.

(b) Ductile iron pipe may not be joined by threaded joints.

(c) Ductile iron pipe may not be joined by brazing.

192.279 **COPPER PIPE.**

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 standard wall pipe, as defined in ANSI Standard B36.10.

192.281 **PLASTIC PIPE.**

(a) 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.

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

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM Specification D2513.

(3) The safety requirements of Appendix A of ASTM Specification D2513 must be met.

(4) The joint may not be heated to accelerate the setting of the cement.

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

(1) 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.

(2) 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.

(3) Heat may not be applied with a torch or other open flame.

(d) Adhesive joints. Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM Specification D2517.

(2) The materials and adhesive must be compatible with each other.

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

(1) The gasket material in the coupling must be compatible with the plastic.

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

192.283 **PLASTIC PIPE: QUALIFYING JOINING PROCEDURES.**

(a) Heat Fusion, Solvent Cement, and Adhesive Joints. Before any written procedure established under 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:

(1) The burst test requirements of--

(i) In the case of thermoplastic pipe, Paragraph 8.6 (Sustained Pressure Test) or Paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D2513; or

(ii) In the case of thermosetting plastic pipe, Paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or Paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517;

(2) 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

(3) For procedures intended for nonlateral pipe connections, follow the tensile test requirements of ASTM D 638, except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) Mechanical Joints. Before any written procedure established under 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 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D 638-77a (except for conditioning).

(2) 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.

(3) The speed of testing is 5.0 mm (0.20 in) per minute, plus or minus 25 percent.

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

(5) Pipe specimens 102 mm (4 in) 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 38°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 test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

(6) Each specimen that fails at the grips must be retested using new pipe.

(7) 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.

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

(d) 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.

(Section (a)(1) Revised, Amdt. 192-34B, effective January 2, 1981)

192.285 PLASTIC PIPE: QUALIFYING PERSONS TO MAKE JOINTS.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by--

(1) Appropriate training or experience in the use of the procedure; and

(2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be--

(1) 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

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under 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 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.

(c) A person must be requalified under an applicable procedure, if during any 12-month period that person--

(1) Does not make any joints under that procedure; or

(2) Has 3 joints or 3 percent of the joints made, whichever is greater, under that procedure that are found unacceptable by testing under 192.513.

(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in his system is qualified in accordance with this section.

(Section 285 (b)(2)(i) Amended Amdt. 192-34B, effective January 2, 1981)

192.287 PLASTIC PIPE: INSPECTION OF JOINTS.

No person may carry out the inspection of joints in plastic pipes required by 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.

Subpart G--General Construction Requirements for Transmission Lines and Mains

192.301 SCOPE.

This subpart prescribes minimum requirements for constructing transmission lines and mains.

192.303 COMPLIANCE WITH SPECIFICATIONS OR STANDARDS.

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

192.305 INSPECTION: GENERAL.

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

192.307 INSPECTION OF MATERIALS.

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.

192.309 REPAIR OF STEEL PIPE.

(a) 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:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS:

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

(2) A dent that affects the longitudinal weld or a circumferential weld.

(3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of:

(i) More than one-quarter inch in pipe 12 3/4 inches or less in outer diameter; or

(ii) More than 2 percent of the nominal pipe diameter in pipe over 12 3/4 inches in outer diameter.

For the purpose of this section 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.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, 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:

(1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

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

(e) 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.

192.311 REPAIR OF PLASTIC PIPE.

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired by a patching saddle or removed.

192.313 BENDS AND ELBOWS.

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

(1) A bend must not impair the serviceability of the pipe.

(2) For pipe more than 4 inches in nominal diameter, the difference between the maximum and minimum diameter at a bend must not be more than 2 1/2 percent of the nominal diameter.

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

(4) 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 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(b) 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.

(c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on

steel pipe that is 2 inches or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch.

192.315 WRINKLE BENDS IN STEEL PIPE.

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

(b) Each wrinkle bend on steel pipe must comply with the following:

(1) The bend must not have any sharp kinks.

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

(3) On pipe 16 inches or larger in diameter, the bend may not have a deflection of more than 1 1/2 for each wrinkle.

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

192.317 PROTECTION FROM HAZARDS.

(a) Each transmission line or main must be protected from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, offshore pipelines must be protected from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or 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.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

192.319 INSTALLATION OF PIPE IN A DITCH.

(a) When installed in a ditch, each transmission line that is to be operated at a pressure producing a hoop stress of 20 percent 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.

(b) When a ditch for a transmission line or main is backfilled, it must be backfilled in a manner that--

(1) Provides firm support under the pipe; and

(2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.

(c) All offshore pipe in water at least 12 feet deep, but not more than 200 feet deep as measured from the mean low tide, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means.

192.321 INSTALLATION OF PLASTIC PIPE.

(a) Plastic pipe must be installed below ground level.

(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.

(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.

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

(e) Plastic pipe that is not encased must have an electrically conductive wire or

other means of locating the pipe while it is underground.

(f) 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.

192.323 CASING.

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

(a) The casing must be designed to withstand the superimposed loads.

(b) If there is a possibility of water entering the casing, the ends must be sealed.

(c) 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 72 percent of SMYS.

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

192.325 UNDERGROUND CLEARANCE.

(a) Each transmission line must be installed with at least 12 inches 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.

(b) 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.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, 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.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in 192.175(b).

192.327 COVER.

(a) Except as provided in paragraphs (c) and (e) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	*Normal soil*	*Consolidated rock*
	Inches	Inches
Class 1 locations	30	18
Class 2, 3, and 4 locations	36	24
Drainage ditches of public roads and railroad crossings	36	24

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches of cover.

(c) 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.

(d) A main may be installed with less than 24 inches of cover if the law of the State or municipality--

(1) Establishes a minimum cover of less than 24 inches.

(2) Requires that mains be installed in a common trench with other utility lines; and

(3) Provides adequately for prevention of damage to the pipe by external forces.

(e) All pipe which is installed in a navigable river, stream, or harbor must have a minimum cover of 48 inches in soil

or 24 inches in consolidated rock, and all pipe installed in any offshore location under water less than 12 feet deep, as measured from mean low tide, must have a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of the pipe and the natural bottom. However, less than the minimum cover is permitted in accordance with paragraph (c) of this section.

Subpart H--Customer Meters, Service Regulators, and Service Lines

192.351 SCOPE.

This subpart prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

192.353 CUSTOMER METERS AND REGULATORS: LOCATION.

(a) 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 and other damage. However, the upstream regulator in a series may be buried.

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

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

(d) 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.

192.355 CUSTOMER METERS AND REGULATORS: PROTECTION FROM DAMAGE.

(a) 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.

(b) Service regulator vents and relief vents. The outside terminal of each service regulator vent and relief vent must:

(1) Be rain and insect resistant;

(2) 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

(3) Be protected from damage caused by submergence in areas where flooding may occur.

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

192.357 CUSTOMER METERS AND REGULATORS: INSTALLATION.

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

(b) 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 part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

192.359 CUSTOMER METER INSTALLATIONS OPERATING PRESSURE.

(a) A meter may not be used at a

pressure that is more than 67 percent of the manufacturer's shell test pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i.g.

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

192.361 SERVICE LINES: INSTALLATION.

(a) Depth. Each buried service line must be installed with at least 12 inches of cover in private property and at least 18 inches of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) 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.

(c) 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.

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

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

(1) In the case of a metal service line, be protected against corrosion;

(2) In the case of plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) Installation of service lines under buildings. Where an underground service line is installed under a building:

(1) It must be encased in a gas-tight conduit;

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

(3) 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.

192.363 SERVICE LINES: VALVE REQUIREMENTS.

(a) Each service line must have a service-line valve that meets the applicable requirements of Subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.

(b) 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.

(c) Each service-line valve on a high-pressure service line, installed above ground 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.

192.365 SERVICE LINES: LOCATION OF VALVES.

(a) 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.

(b) Outside valves. Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.

(c) 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.

192.367 SERVICE LINES: GENERAL REQUIREMENTS FOR CONNECTIONS TO MAIN PIPING.

(a) 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.

(b) Compression-type connection to mains. Each compression-type service line to main connection must:

(1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

(2) 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.

192.369 SERVICE LINES: CONNECTION TO CAST IRON OR DUCTILE IRON MAINS.

(a) 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 192.273.

(b) If a threaded tap is being inserted, the requirements of 192.151 (b) and (c) must also be met.

192.371 SERVICE LINES; STEEL.

Each steel service line to be operated at less than 100 p.s.i.g., must be constructed of pipe designed for a minimum of 100 p.s.i.g.

192.373 SERVICE LINES; CAST IRON AND DUCTILE IRON.

(a) Cast or ductile iron pipe less than 6 inches in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

(c) A cast iron or ductile iron service line may not be installed in unstable soil or under a building.

192.375 SERVICE LINE: PLASTIC.

(a) Each plastic service line outside a building must be installed below ground level, except that it may terminate above the ground and outside the building, if--

(1) The above ground part of the plastic service line is protected against deterioration and external damage; and

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

(b) Each plastic service line inside a building must be protected against external damage.

192.377 SERVICE LINES; COPPER.

Each copper service line installed within a building must be protected against external damage.

192.379 NEW SERVICE LINES NOT IN USE.

Each service line that is not placed in service upon completion of installation

must comply with one of the following until the customer is supplied with gas:

(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.

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

Subpart I--Requirements for Corrosion Control

192.451 SCOPE.

This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

192.452 APPLICABILITY TO CONVERTED PIPELINES.

Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with paragraph 192.14 must meet the requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

192.453 GENERAL.

Each operator shall establish procedures to implement the requirements of this subpart. These procedures, including those for the design, installation, operation and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified by experience and training in pipeline corrosion control methods.

192.455 EXTERNAL CORROSION CONTROL: BURIED OR SUBMERGED PIPELINES INSTALLED AFTER JULY 31, 1971.

(a) Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of 192.461.

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

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. Tests, investigation, or experience must be backed by documented proof to substantiate results and determinations. However, within 6 months after an installation is made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to

exceed 20 feet, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a) (2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that:

(1) For a copper pipeline, a corrosive environment does not exist; or

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

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a) (2) of this section.

(e) 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 8, unless tests or experience indicate its suitability in the particular environment involved.

(f) This section does not apply to electrically isolated, metal alloy fittings in plastic pipelines if--

(1) For the size fitting to be used, an operator can show by tests, investigation, or experience in the area of application, that adequate corrosion control is provided by alloyage:

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

192.457 EXTERNAL CORROSION CONTROL: BURIED OR SUBMERGED PIPELINES INSTALLED BEFORE AUGUST 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line 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 subpart. For the purposes of this subpart, 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.

(b) 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 subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

(2) Bare or coated pipes at compressor, regulator, and measuring stations.

(3) Bare or coated distribution lines. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other effective means, documented by data substantiating results and determinations.

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

(d) When a condition of active external corrosion is found, positive action must be taken to mitigate and control the

effects of the corrosion. Schedules must be established for application of corrosion control. Monitoring effectiveness must be adequate to mitigate and control the effects of the corrosion prior to its becoming a public hazard or endangering public safety.

192.459 EXTERNAL CORROSION CONTROL: EXAMINATION OF BURIED PIPELINE WHEN EXPOSED.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion is found, remedial action must be taken to the extent required by 192.483 and the applicable paragraphs of 192.485, 192.487, or 192.489.

192.461 EXTERNAL CORROSION CONTROL: PROTECTIVE COATING.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must:

(1) Be applied on a properly prepared surface;

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil stress; and

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) 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.

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

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

192.463 EXTERNAL CORROSION CONTROL: CATHODIC PROTECTION.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this subpart. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential:

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

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

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

192.465 EXTERNAL CORROSION CONTROL: MONITORING.

(a) Each pipeline that is under cathodic protection must be tested at least once

each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of 192.463. Test points (electrode locations) used when taking pipe-to-soil readings for determining cathodic protection shall be selected so as to give representative pipe-to-soil readings. Test points (electrode locations) over or near an anode or anodes shall not, by themselves, be considered representative readings. However, if tests at those intervals are impractical for separately protected sections of pipeline not in excess of 100 feet, these pipeline sections may be surveyed on a sampling basis. At least 10 percent of these separately protected sections, distributed over the entire system, must be surveyed each calendar year with a different 10 percent checked each subsequent year, so that all separately protected pipeline sections are tested in each 10-year period.

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

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

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

(e) After the initial evaluation required by paragraphs (b) and (c) of 192.455 and paragraph (b) of 192.457, each operator shall, at intervals not exceeding 3 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other effective means, documented by data substantiating results and determinations.

(f) When leak detection surveys are used to determine areas of active corrosion, the survey frequency must be increased to monitor the corrosion rate and control the condition. The detection equipment used must have sensitivity adequate to detect gas concentration below the lower explosive limit and be suitable for such use.

192.467 EXTERNAL CORROSION CONTROL: ELECTRICAL ISOLATION.

(a) 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.

(b) One 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.

(c) Except for unprotected copper inserted in 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.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

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

(f) 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.

192.469 **EXTERNAL CORROSION CONTROL: TEST STATIONS.**

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

192.471 **EXTERNAL CORROSION CONTROL: TEST LEADS.**

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

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

(c) 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.

192.473 **EXTERNAL CORROSION CONTROL: INTERFERENCE CURRENTS.**

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

(b) 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.

192.475 **INTERNAL CORROSION CONTROL: GENERAL.**

(a) 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. "Corrosive gas" means a gas which, by chemical reaction with the pipe to which it is exposed, usually metal, produces a deterioration of the material.

(b) 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:

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of 192.485, 192.487, or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

(c) Gas containing more than 0.1 grain of hydrogen sulfide per 100 standard cubic feet may not be stored in pipe-type or bottle-type holders.

192.477 **INTERNAL CORROSION CONTROL: MONITORING**

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 times each calendar year, but with intervals not exceeding 7 1/2 months.

192.479 **ATMOSPHERIC CORROSION CONTROL: GENERAL**

(a) Pipelines installed after July 31, 1971. Each above ground 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, if the operator can demonstrate by test, investigation, or experience in the area of application, that a corrosive atmosphere does not exist.

(b) Pipelines installed before August 1, 1971. Each operator having an above-ground pipeline or portion of a pipeline installed before August 1, 1971 that is exposed to the atmosphere, shall:

(1) Determine the areas of atmospheric corrosion on the pipeline;

(2) If atmospheric corrosion is found, take remedial measure to the extent required by the applicable paragraphs of 192.485, 192.487, or 192.489; and

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

(c) "Atmospheric corrosion" means aboveground corrosion caused by chemical or electro-chemical reaction between a pipe material, usually a metal, and its environment, that produces a deterioration of the material.

192.481 ATMOSPHERIC CORROSION CONTROL: MONITORING

After meeting the requirements of Section 192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipelines and at least once each calendar year, but with intervals not exceeding 15 months, for offshore pipelines, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

192.483 REMEDIAL MEASURES: GENERAL.

(a) 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 192.461.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.

(c) 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 in accordance with this subpart.

192.485 REMEDIAL MEASURES: TRANSMISSION LINES

(a) 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 the 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.

(b) 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.

192.487 REMEDIAL MEASURES: DISTRIBUTION LINES OTHER THAN CAST IRON OR DUCTILE IRON LINES.

(a) 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 30 percent 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.

(b) 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.

192.489 REMEDIAL MEASURES: CAST IRON AND DUCTILE IRON PIPELINES.

(a) 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.

(b) 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.

192.491 CORROSION CONTROL: RECORDS.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, other than unrecorded galvanic anodes installed before August 1, 1971, and neighboring structures bonded to the cathodic protection system.

(b) Each of the following records must be retained for as long as the pipeline remains in service:

(1) Each record or map required by paragraph (a) of this section.

(2) Records of each test, survey, or inspection required by this subpart, in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist.

Subpart J--Test Requirements

192.501 SCOPE.

This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

192.503 GENERAL REQUIREMENTS.

(a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until:

(1) It has been tested in accordance with this subpart to substantiate the proposed maximum allowable operating pressure; and

(2) Each potentially hazardous leak has been located and eliminated.

(b) The test medium must be liquid, air, natural gas, or inert gas that is:

(1) Compatible with the material of which the pipeline is constructed;

(2) Relatively free of sedimentary materials; and

(3) Except for natural gas, nonflammable.

(c) Except as provided in 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

(d) Each weld used to tie-in a test segment of pipeline is excepted from the test requirements of this subpart.

192.505 **STRENGTH TEST REQUIREMENTS FOR STEEL PIPELINE TO OPERATE AT A HOOP STRESS OF 30 PERCENT OR MORE OF SMYS.**

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section 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 300 feet of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet of such a building, but in no event may the test section be less than 600 feet unless the length of the newly installed or relocated pipe is less than 600 feet. However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) 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.

(c) Except as provided in paragraph (e) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

(d) 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:

(1) The component was tested to at least the pressure required for the pipeline to which it is being added; or

(2) 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.

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

192.507 **TEST REQUIREMENTS FOR PIPELINES TO OPERATE AT A HOOP STRESS LESS THAN 30 PERCENT OF SMYS AND ABOVE 100 P.S.I.G.**

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and above 100 p.s.i.g., must be tested in accordance with the following:

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

(b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium:

(1) A leak test must be made at a pressure between 100 p.s.i.g., and the pressure required to produce a

hoop stress of 20 percent of SMYS; or

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

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

192.509 TEST REQUIREMENTS FOR PIPELINE TO OPERATE AT OR BELOW 100 P.S.I.G.

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at or below 100 p.s.i.g., must be leak tested in accordance with the following:

(a) The test procedure used must ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) Each main that is to be operated at less than 1 p.s.i.g., must be tested to at least 10 p.s.i.g., and each main to be operated at or above 1 p.s.i.g., must be tested to at least 90 p.s.i.g.

192.511 TEST REQUIREMENTS FOR SERVICE LINES.

(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section 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.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i.g., but not more than 40 p.s.i.g., must be given a leak test at a pressure of not less than 50 p.s.i.g.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i.g., must be tested to at least 90 p.s.i.g., except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance with 192.507 of this subpart.

192.513 TEST REQUIREMENTS FOR PLASTIC PIPELINES.

(a) Each segment of a plastic pipeline must be tested in accordance with this section.

(b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure must be at least 150 percent of the maximum operating pressure or 50 p.s.i.g., whichever is greater. However, the maximum test pressure may not be more than three times the design pressure of the pipe.

(d) The temperature of thermoplastic material must not be more than 100° F.during the test.

192.515 ENVIRONMENTAL PROTECTION AND SAFETY REQUIREMENTS.

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent 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.

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

192.517 RECORDS.

Each operator shall make and retain for the useful life of the pipeline, a record of each test performed under paragraphs 192.505 and 192.507. The record must contain at least the following information:

(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.

(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.

Subpart K--Uprating

192.551 SCOPE.

This subpart prescribes minimum requirements for increasing maximum allowable operating pressures (uprating) for pipelines.

192.553 GENERAL REQUIREMENTS.

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

(1) At the end of each incremental increase, the pressure must be held constant while the entire segment of pipeline that is affected is checked for leaks.

(2) 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.

(b) 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 subpart, of all work performed, and of each pressure test conducted, in connection with the uprating.

(c) Written plan. Each operator who uprates a segment of pipeline shall establish a written procedure that will ensure that each applicable requirement of this subpart is complied with.

(d) Limitation on increase in maximum allowable operating pressure. Except as provided in 192.555 (c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location.

192.555 UPRATING: TO A PRESSURE THAT WILL PRODUCE A HOOP STRESS OF 30 PERCENT OR MORE OF SMYS IN STEEL PIPELINES.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to an operating pressure that will produce a hoop stress of 30 percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure the operator shall:

(1) 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 part; and

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

(c) After complying with paragraph (b) of this section, 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 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).

(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met:

(1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

(2) 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 part;

(ii) The new maximum operating pressure does not exceed 80 percent 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 part.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d) (2) of this section, the increase in pressure must be made in increments that are equal to:

(1) 10 percent of the pressure before the uprating; or

(2) 25 percent of the total pressure increase, whichever produces the fewer number of increments.

192.557 UPRATING: STEEL PIPELINES TO A PRESSURE THAT WILL PRODUCE A HOOP STRESS LESS THAN 30 PERCENT OF SMYS; PLASTIC, CAST IRON, AND DUCTILE IRON PIPELINES.

(a) Unless the requirements of this section have been met, no person may subject:

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

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

(b) Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:

(1) Review the design, operating, and maintenance history of the segment of pipeline;

(2) Make a leakage survey (if it has been more than 1 year since the last survey) 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;

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

(4) 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;

(5) 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

(6) 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.

(c) After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i.g., or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b) (6) of this section apply, there must be at least two approximately equal incremental increases.

(d) If records for cast iron or ductile iron pipeline facilities are not complete enough to ascertain compliance with 192.117 or 192.119, as applicable, the following procedures must be followed:

(1) If the original laying conditions cannot be ascertained, the operator shall assume, when applying the design formulas of ANSI C101-67 that cast iron pipe was supported on blocks with tamped backfill and, when applying the design formulas of ANSI A21.50, that ductile iron pipe was laid without blocks with tamped backfill.

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

(3) Unless the actual nominal wall thickness is known, the operator shall determine the wall thickness by cutting and measuring coupons from at least three spearate 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*
3-8	0.075	0.065	0.065
10-12	0.08	0.07	0.07
14-24	0.08	0.08	0.075
30-42	0.09	0.09	0.075
48	0.09	0.09	0.08
54-60	0.09	- - -	- - -

NOTE--The nominal wall thickness of the cast iron is the standard thickness listed in table 10 or table 11, as applicable, of ANSI C101-67 nearest the value obtained under this subparagraph. The nominal wall thickness of ductile iron pipe is the standard thickness listed in table 6 of ANSI A21.50 nearest the value obtained under this subparagraph.

(4) 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 11,000 p.s.i. and a modulus of rupture of 31,000 p.s.i.

Subpart L--Operations

192.601 SCOPE.

This subpart prescribes minimum requirements for the operation of pipeline facilities.

192.603 GENERAL PROVISIONS.

(a) No person may operate a segment of

pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall establish a written operating and maintenance plan meeting the requirements of this part and keep records necessary to administer the plan.

192.605 ESSENTIALS OF OPERATING AND MAINTENANCE PLAN.

Each operator shall include the following in its operating and maintenance plan:

(a) Instructions for employees covering operating and maintenance procedures during normal operations and repairs.

(b) Items required to be included by the provisions of Subpart M of this part.

(c) Specific programs relating to facilities presenting the greatest hazard to public safety either in an emergency or because of extraordinary construction or maintenance requirements.

(d) A program for conversion procedures, if conversion of a low-pressure distribution system to a higher pressure is contemplated.

(e) Provision for periodic inspections to ensure that operating pressures are appropriate for the class location.

192.607 INITIAL DETERMINATION OF CLASS LOCATION AND CONFIRMATION OR ESTABLISHMENT OF MAXIMUM ALLOWABLE OPERATING PRESURE.

(a) Before April 15, 1971, each operator shall complete a study to determine for each segment of pipeline with a maximum allowable operating pressure that will produce a hoop stress that is more than 40 percent of SMYS:

(1) The present class location of all such pipeline in its system; and

(2) Whether the hoop stress corresponding to the maximum allowable operating pressure for each segment of pipeline is commensurate with the present class location.

(b) Each segment of pipeline that has been determined under paragraph (a) of this section to have an established maximum allowable operating pressure producing a hoop stress that is not commensurate with the class location of the segment of pipeline and that is found to be in satisfactory condition, must have the maximum allowable operating pressure confirmed or revised in accordance with 192.611. The confirmation or revision must be completed not later than December 31, 1974.

(c) Each operator required to confirm or revise an established maximum allowable operating pressure under paragraph (b) of this section shall, not later than December 31, 1971, prepare a comprehensive plan, including a schedule, for carrying out the confirmations or revisions. The comprehensive plan must also provide for confirmation or revisions determined to be necessary under 192.609, to the extent that they are caused by changes in class locations taking place before July 1, 1973.

192.609 CHANGE IN CLASS LOCATION: REQUIRED STUDY.

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent 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:

(a) The present class location for the segment involved.

(b) The design, construction, and testing procedures followed in the original

construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.

(c) The physical condition of the segment to the extent it can be ascertained from available records;

(d) The operating and maintenance history of the segment;

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

(f) 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.

192.611 CHANGE IN CLASS LOCATION: CONFIRMATION OR REVISION OF MAXIMUM ALLOWABLE OPERATING PRESSURE.

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 as follows:

(a) If the segment involved has been previously tested in place to at least 90 percent of its SMYS for a period of not less than 8 hours, the maximum allowable operating pressure must be confirmed or reduced so that the corresponding hoop stress will not exceed 72 percent of SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(b) If the segment involved has not been previously tested in place as described in paragraph (a) of this section, the maximum allowable operating pressure must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(c) If the segment of pipeline involved has not been qualified for operation under paragraph (a) or (b) of this section, it must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established so as to be equal to or less than the following:

(1) 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.

(2) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(3) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of the SMYS in Class 4 locations.

(d) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of 192.553 and 192.555.

(e) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under 192.609 must be completed as follows:

(1) Confirmation or revision due to changes in class location that occur before July 1, 1973, must be completed not later than December 31, 1974.

(2) Confirmation or revision due to changes in class location that occur on or after July 1, 1973, must be completed within 18 months of the change in class location.

192.613 **CONTINUING SURVEILLANCE.**

(a) 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.

(b) 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 192.619 (a) and (b).

192.614 **DAMAGE PREVENTION PROGRAM.**

(a) Except for pipelines listed in paragraph (c) of this section, each operator of a buried pipeline shall carry out in accordance with this section a written program to prevent damage to that pipeline by excavation activities. For the purpose of this section, "excavation activities" include excavation, blasting, boring, tunneling, backfilling, the removal of above ground structures by either explosive or mechanical means, and other earth moving operations. An operator may perform any of the duties required by paragraph (b) of this section through participation in a public service program, such as a "one-call" system, but such participation does not relieve the operator of responsibility for compliance with this section.

(b) The damage prevention program required by paragraph (a) of this section must, at a minimum--

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provide for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (b) (1) of the following as often as needed to make them aware of the damage prevention program:

(i) The program's existence and purpose; and

(ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) Provide for actual notification of persons who give notice of their intent to excavate of whether there are buried pipelines in the area of excavation activity and, if so, the type of temporary marking to be provided and how to identify the markings.

(5) Provide for the temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

(6) 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.

(c) A damage prevention program under

this section is not required for the following pipelines:

(1) Pipelines in a Class 1 or 2 location.

(2) Pipelines in a Class 3 location defined by Section 192.5(d)(2) that are marked in accordance with Section 192.707.

(3) Pipelines to which access is physically controlled by the operator.

(4) Pipelines that are part of a petroleum gas system subject to Section 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.

(Amdts. 192-40, effective April 1, 1983)

192.615 **EMERGENCY PLANS.**

(a) 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:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response 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.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) 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.

(9) Safely restoring any service outage.

(10) Beginning action under 192.617, if applicable, as soon after the end of the emergency as possible.

(b) Each operator shall--

(1) 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 (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to--

(1) Learn the responsibility and

resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

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

(d) 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.

192.617 INVESTIGATION OF FAILURES.

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.

192.619 MAXIMUM ALLOWABLE OPERATING PRESURE: STEEL OR PLASTIC PIPELINES.

(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i.g., or more, the test pressure is divided by a factor determined in accordance with the following table:

	Factors, segment--*		
Class location	*Installed before 11-12-70*	*Installed after 11-11-70*	*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

**For offshore segments installed, uprated, or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated, or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters (including a pipe riser), the factor is 1.5.*

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970 (or in the case of offshore gathering lines, July 1, 1976), unless the segment was tested in accordance with paragraph (a)(2) of this section after July 1, 1965 (or in the case of offshore gathering lines, July 1, 1971), or the segment was uprated in accordance with Subpart K of this part.

(4) For furnace butt welded steel pipe, a pressure equal to 60 percent

of the mill test pressure to which the pipe was subjected.

(5) For steel pipe other than furnace butt welded pipe, a pressure equal to 85 percent of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

(6) 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.

(b) No person may operate a segment to which paragraph (a) (6) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with 192.195.

(c) Notwithstanding the other requirements of this section, 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 5 years preceding July 1, 1970, or in the case of offshore gathering lines, July 1, 1976, subject to the requirements of Section 192.611.

192.621 **MAXIMUM ALLOWABLE OPERATING PRESSURE: HIGH-PRESSURE DISTRIBUTION SYSTEMS.**

(a) 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:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.

(2) 60 p.s.i.g., for a segment of a distribution system otherwise designed to operate at over 60 p.s.i.g., unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of 192.197(c).

(3) 25 p.s.i.g., in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) 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.

(b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with 192.195.

192.623 **MAXIMUM ANDMINIMUM ALLOWABLE OPERATING PRESSURE: LOW-PRESSURE DISTRIBUTION SYSTEMS.**

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

192.625 **ODORIZATION OF GAS.**

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air

of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless--

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant--

(A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction; or

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) 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.

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section.

(g) The odorization requirements of Part 190 of this chapter, as in effect on August 12, 1970, must be complied with, in each State in which odorization of gas in transmission lines is required by that part, until the earlier of the following dates:

(1) January 1, 1977; or

(2) The date upon which the distribution companies in that State are odorizing gas in accordance with paragraphs (a) through (f) of this section.

192.627 TAPPING PIPELINES UNDER PRESSURE.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

192.629 PURGING OF PIPELINES.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one 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.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one 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.

192.629 PURGING OF PIPELINES.

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one 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.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one 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.

Subpart M--Maintenance

192.701 SCOPE.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

192.703 GENERAL.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

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

(c) Hazardous leaks must be repaired promptly.

192.705 TRANSMISSION LINES: PATROLLING.

(a) 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.

(b) The frequency of patrols is determined by the size of the line, the operating pressure, 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 crossings*	*At all other places*
1, 2	7½ months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3	4½ months; but at least four times each calendar year.	7½ months; but at least twice each calendar year.
4	4½ months; but at least four times each calendar year.	4½ months; but at least four times each calendar year.

192.706 TRANSMISSION LINES: LEAKAGE SURVEYS.

(a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with Section 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted--

(1) In Class 3 locations, at intervals not exceeding 7½ months, but at least twice each calendar year; and

(2) In Class 4 locations, at intervals not exceeding 4½ months, but at least four times each calendar year.

192.707 LINE MARKERS FOR MAINS AND TRANSMISSION LINES.

(a) Buried pipelines. Except as provided

in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

(1) At each crossing of a public road and railroad; and

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

(b) Exceptions for buried pipelines. Line markers are not required for buried mains and transmission lines--

(1) Located offshore or at crossings of or under waterways and other bodies of water; or

(2) In Class 3 or 4 locations--

(i) Where placement of a marker is impractical; or

(ii) Where a damage prevention program is in effect under § 192.614.

(c) Pipelines aboveground. Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

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

(1) 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 high with one-quarter inch stroke.

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

[Amdt. 192-44, 48 FR25208 June 6, 1983]

192.709 **TRANSMISSION LINES: RECORD KEEPING.**

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

192.711 **TRANSMISSION LINES: GENERAL REQUIREMENTS FOR REPAIR PROCEDURES.**

(a) Each operator shall take immediate temporary measures to protect the public whenever:

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

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

(b) Except as provided in 192.717 (a)(3), no operator may use a welded patch as a means of repair.

192.713 **TRANSMISSION LINES: PERMANENT FIELD REPAIR OF IMPERFECTIONS AND DAMAGES.**

(a) Except as provided in paragraph (b) of this section, each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of SMYS must be repaired as follows:

(1) 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.

(2) 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.

(3) If the segment is not taken out of service, the operating pressure must be reduced to a safe level during the repair operations.

(b) Submerged offshore pipelines and 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.

192.715 **TRANSMISSION LINES: PERMANENT FIELD REPAIR OF WELDS.**

Each weld that is unacceptable under 192.241 (c) must be repaired as follows:

(a) 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 192.245.

(b) A weld may be repaired in accordance with 192.245 while the segment of transmission line is in service if:

(1) The weld is not leaking;

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

(3) Grinding of the defective area can be limited so that at least 1/8-inch thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

192.717 **TRANSMISSION LINES: PERMANENT FIELD REPAIR OF LEAKS.**

(a) Except as provided in paragraph (b) of this section, each permanent field repair of a leak on a transmission line must be made as follows:

(1) 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.

(2) 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 40 percent of SMYS.

(3) 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 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 of the diameter of the pipe in size.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

192.719 **TRANSMISSION LINES: TESTING OF REPAIRS.**

(a) Testing of replacement pipe.

(1) 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.

(2) The test required by subparagraph (1) of this paragraph may be made on the pipe before it is installed, but all field girth butt welds that are not strength tested must be tested after installation by nondestructive tests meeting the requirements of 192.243.

(b) Testing of repairs made by welding. Each repair made by welding in accordance with 192.713, 192.715 and 192.717 must be examined in accordance with 192.241.

192.721 DISTRIBUTION SYSTEMS: PATROLLING.

(a) 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.

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled at intervals not exceeding 4½ months, but at least four times each calendar year.

192.723 DISTRIBUTION SYSTEMS: LEAKAGE SURVEYS AND PROCEDURES.

(a) Each operator of a distribution system shall provide for periodic leakage surveys in its operating and maintenance plan.

(b) 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:

(1) A gas detector 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 15 months, but at least once each calendar year.

(2) Leakage surveys of the distribution system outside of the principal business areas must be made as frequently as necessary, but at intervals not exceeding 5 years.

192.725 TEST REQUIREMENTS FOR REINSTATING SERVICE LINES

(a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. 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.

192.727 ABANDONMENT OR ACTIVATION OF FACILITIES.

(a) Each operator shall provide in its operating and maintenance plan for abandonment or deactivation of pipelines, including provisions for meeting each of the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; 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.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; 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.

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

(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.

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

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

(f) Each abandoned vault must be filled with a suitable compacted material.

192.729 COMPRESSOR STATIONS: PROCEDURES FOR GAS COMPRESSOR UNITS.

Each operator shall establish starting, operating, and shutdown procedures for gas compressor units.

192.731 COMPRESSOR STATIONS: INSPECTION AND TESTING OF RELIEF DEVICES.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

192.733 COMPRESSOR STATIONS: ISOLATION OF EQUIPMENT FOR MAINTENANCE OR ALTERATIONS.

Each operator shall establish procedures for mantaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

192.735 COMPRESSOR STATIONS: STORAGE OF COMBUSTIBLE MATERIALS.

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

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

192.737 PIPE-TYPE AND BOTTLE-TYPE HOLDERS: PLAN FOR INSPECTION AND TESTING.

Each operator having a pipe-type or bottle-type holder shall establish a plan for the systematic, routine inspection and testing of these facilities, including the following:

(a) Provision must be made for detecting external corrosion before the strength of the container has been impaired.

(b) Periodic sampling and testing of gas

in storage must be made to determine the dew point of vapors contained in the stored gas, that if condensed, might cause internal corrosion or interfere with safe operation of the storage plant.

(c) The pressure control and pressure limiting equipment must be inspected and tested periodically to determine that it is in a safe operating condition and has adequate capacity.

192.739 PRESSURE LIMITING AND REGULATING STATIONS: INSPECTION TESTING.

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

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the correct pressure; and

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

192.741 PRESSURE LIMITING AND REGULATING STATIONS: TELEMETERING OR RECORDING GAGES.

(a) Each distribution system supplied by more that one district pressure regulating station must be equipped with telemetering or recording pressure gages to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gages in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) 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.

192.743 PRESSURE LIMITING AND REGULATING STATIONS: TESTING OF RELIEF DEVICES.

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 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.

(b) 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 one 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.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

192.745 VALVE MAINTENANCE: TRANSMISSION LINES.

Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

192.747 VALVE MAINTENANCE: DISTRIBUTION SYSTEMS.

Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15

months, but at least once each calendar year.

192.749 **VAULT MAINTENANCE:**

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

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

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

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

192.751 **PREVENTION OF ACCIDENTAL IGNITION.**

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:

(a) 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.

(b) 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.

(c) Post warning signs, where appropriate.

192.753 **CAULKED BELL AND SPIGOT JOINTS.**

(a) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i.g. or more must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or device which--

(i) Does not reduce 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 192.53 (a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures of less than 25 p.s.i.g., and is exposed for any reason, must be sealed by a means other than caulking.

192.755 **PROTECTING CAST IRON PIPELINES.**

When an operator has knowledge that the support for a segment of a buried cast iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) 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 192.317(a), 192.319, and 192.361(b) - (d).

Appendix A
Incorporated by Reference

I. LIST OF ORGANIZATIONS AND ADDRESS.

A. American National Standards Institute (ANSI), 1430 Broadway, New York, N.Y. 10018.

B. American Petroleum Institute (API), 1801 K Street N.W., Washington, D.C. 20006 or 300 Corrigan Tower Building, Dallas, Tex. 75201.

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

D. American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pa. 19103.

E. Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 5203 Leesburg Pike, Suite 502, Falls Church, Va. 22041.

F. National Fire Protection Association (NFPA), Batterymarch Park, Quincy, Massachusetts 02269.

II. DOCUMENTS INCORPORATED BY REFERENCE NUMBERS IN PARENTHESES INDICATE APPLICABLE EDITIONS.

A. American Petroleum Institute:

(1) API Specification 5A "API Specification for Casing, Tubing, and Drill Pipe" (1979).

(2) API Specification 6A "API Specification for Wellhead Equipment" (1979).

(3) API Specification 6D "API Specification for Pipeline Valves" (1977).

(4) API Specification 5L "API Specification for Line Pipe" (1980).

(5) API Specification 5LS "API Specification for Spiral-Weld Line Pipe" (1980).

(6) API Specification 5LX "API Specification for High-Test Line Pipe" (1980).

(7) API Recommended Practice 5LI "API Recommended Practice for Railroad Transportation of Line Pipe" (1972).

(8) API Standard 1104 "Standard for Welding Pipelines and Related Facilities" (1980).

B. The American Society for Testing and Materials:

(1) ASTM Specification A53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless" (A53-79).

(2) ASTM Specification A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-79b).

(3) ASTM Specification A134 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Plate Pipe, Sizes 16 in. and over" (A134-74).

(4) ASTM Specification A135 "Standard Specification for Electric-Resistance-Welded Steel Pipe" (A135-79).

(5) ASTM Specification A139 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe (Sizes 4 in. and over)" (A139-74).

(6) ASTM Specification A671 "Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (A671-77).

(7) ASTM Specification A672 "Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (A672-79).

(8) ASTM Specification A691 "Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (A691-79).

(9) ASTM Specification A211 "Standard Specification for Spiral-Welded Steel or Iron Pipe" (A211-75).

(10) ASTM Specification A333 "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (A333-79).

(11) ASTM Specification A372 "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (A372-78).

(12) ASTM Specification A377 "Standard Specifications for Grey Iron and Ductile Iron Pressure Pipe" (A377-79).

(13) ASTM Specification A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for use with High-Pressure Transmission Systems" (A381-79).

(14) ASTM Specification A539 "Standard Specification for Electric Resistance-Welded Coiled Steel Tubing for Gas and Fuel Oil Lines" (A539-79).

(15) ASTM Specification B42 "Standard Specification for Seamless Copper Pipe, Standard Sizes" (B42-80).

(16) ASTM Specification B68 "Standard Specification for Seamless Copper Tube, Bright Annealed" (B68-80).

(17) ASTM Specification B75 "Standard Specification for Seamless Copper Tube" (B75-80).

(18) ASTM Specification B88 "Standard Specification for Seamless Copper Water Tube" (B88-80).

(19) ASTM Specification B251 "Standard Specification for General Requirements for Wrought Seamless Copper and Copper-Alloy Tube" (B251-76).

(20) ASTM Specification D638 "Standard Test Method for Tensile Properties of Plastic" (D638-77a).

(21) ASTM Specification D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (D2513-81).

(22) ASTM Specification D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings (D2517-73) (Reapproved 1979).

C. The American National Standards Institute, Inc.:

(1) ANSI A21.11 "Rubber-Gasket Joints for Ductile-Iron, and Grey Iron Pressure Pipe and Fittings" (A21.11-1979).

(2) ANSI A21.50 "Thickness Design of Ductile-Iron Pipe" (1976).

(3) ANSI A21.52 "Ductile-Iron Pipe, Centrifugally Cast, in Metal Molds or Sand-Lined Molds for Gas" (1976).

(4) ANSI B16.1 "Cast-Iron Pipe Flanges and Flanged Fittings" (1975).

(5) ANSI B16.5 "Steel Pipe Flanges and Flanged Fittings" (1977).

(6) ANSI B16.24 "Bronze Pipe Flanges and Flanged Fitting" (1979).

(7) ANSI B36.10 "Wrought Steel and Wrought Iron Pipe" (1979).

(8) ANSI C101-67 "Thickness Design of Cast-Iron Pipe" (C101-67-1977).

D. The American Society of Mechanical Engineers:

(1) ASME Boiler and Pressure Vessel Code, Section VIII "Pressure Vessels Division 1" (1977).

(2) ASME Boiler and Pressure Vessel Code, Section IX "Welding Qualifications" (1977).

E. Manufacturer's Standardization Society of the Valve and Fittings Industry:

(1) MSP SP-25 "Standard Marking System for Valves, Fittings, Flanges, and Union" (1978).

(2) MSS SP-44 "Steel Pipe Line Flanges" (1975).

(3) MSS SP-70 "Cast-Iron Gate Valves, Flanged and Threaded Ends" (1976).

(4) MSS SP-71 "Cast-Iron Swing Check Valves, Flanged and Threaded Ends" (1976).

(5) MSS SP-78 "Cast-Iron Plug Valves" (1977).

F. National Fire Protection Association:

(1) NFPA Standard 30 "Flammable and Combustible Liquids Code" (1977).

(2) NFPA Standard 58 "Standard for the Storage and Handling of Liquefied Petroleum Gases" (1979).

(3) NFPA Standard 59 "Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants" (1979).

(4) NFPA Standard 59A "Storage and Handling Liquefied Natural Gas" (1979).

(5) "National Electrical Code" NFPA-70 (ANSI) (1978).

Appendix B
Qualification of Pipe

I. **LISTED PIPE SPECIFICATIONS. NUMBERS IN PARENTHESES INDICATE APPLICABLE EDITIONS.**

API 5L--Steel pipe (1980).
API 5LS--Steel pipe (1980).
API 5LX--Steel pipe (1980).
ASTM A53--Steel pipe (1979).
ASTM A106--Steel pipe (1979).
ASTM A134--Steel pipe (1974).
ASTM A135--Steel pipe (1979).
ASTM A139--Steel pipe (1974).
ASTM A211--Steel and iron pipe (1975).
ASTM A333--Steel pipe (1979).
ASTM A377--Cast iron pipe (1979).
ASTM A381--Steel pipe (1979).
ASTM A539--Steel tubing (1979).
ASTM A671--Steel pipe (1977).
ASTM A672--Steel pipe (1979).
ASTM A691--Steel pipe (1979).
ASTM B42--Copper pipe (1980).
ASTM B68--Copper tubing (1980).
ASTM B75--Copper tubing (1980).
ASTM B88--Copper tubing (1980).
ASTM B251--Copper pipe and tubing-(1976).
ASTM D2513--Thermoplastic pipe and tubing-(1981).
ASTM D2517--Thermosetting plastic pipe and tubing (1973).
ANSI A21.52--Ductile iron pipe (1971).

II. **STEEL PIPE OF UNKNOWN OR UNLISTED SPECIFICATION.**

A. **Bending Properties.** For pipe 2 inches or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing

cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53, except that the number of tests 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 Subpart E of this part. 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 4 inches in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches or less in diameter, at least one test weld must be made for each 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 minumum yield strength may be taken as 24,000 p.s.i.g., or less or the tensile properties may be established by performing tensile tests as set forth in API Standard 5LX. 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 192.55.

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 part 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 is is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. **Similiarity of specification requirements.** The editions of 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 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 1 of this appendix.

(2) The pipe must be tested in accordance with Subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least 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 Subpart J of this part, the test pressure must be maintained for at least 8 hours.

Appendix C
Qualifications of Welders for Low Stress Level Pipe

I. **BASIC TEST.**

The test is made on pipe 12 inches or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1/8-inch 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 samples of the welder's work, each about 8 inches long with the weld located approximately in the center, are cut from steel service line and tested as follows:

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

(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 subparagraph (1) of this paragraph.

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) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) 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.

(5) 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 subparagraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 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 subparagraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 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 subparagraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 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 alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since 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 8.

C. **Copper structures.** A minimum negative (cathodic) polarization voltage shift of 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 subparagraphs (3) and (4) of paragraph B of this section, 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 considered for valid interpretation of the voltage measurement in paragraph A(1) and (2) and paragraph B(1) of section I of this appendix.

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 paragraphs A(3), B(2), and C of section I of this appendix.

IV. REFERENCE HALF CELLS.

A. Except as provided in paragraphs B and C of this section, 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 commonly used reference half cells are listed below 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.

(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.

Railroad Commission of Texas
Gas Utilities Division

In Re: Safety Regulations for Gas Pipeline Facilities and the Transportation of Gas. **Gas Utilities Docket No. 446**

After due notice the Commission on November 10, 1969, heard testimony from representatives of persons owning or operating gas pipeline facilities, with regard to changes or additions to and the expansion, revision, or modification of the safety code for gas transmission lines, heretofore adopted by the Commission's Order dated August 27, 1969, in Gas Utilities Docket No. 422.

WHEREAS, the authority of the Commission to regulate gas pipeline facilities and the transportation of gas was clarified through the adoption by the 61st Legislature of Article 6053-1, Revised Civil Statutes of Texas; and

WHEREAS, since the adoption of Commission's Order in Gas Utilities Docket No. 422, the Office of Pipeline Safety, Department of Transportation, has published 49 CFR Part 192, known as Minimum Safety Standards, with amendments; and

WHEREAS, the Commission has determined that the standards of design, construction, maintenance, and operation of gas pipeline facilities provided in said 49 CFR Part 192, with amendments, are more stringent than the safety code heretofore in effect within the State of Texas.

IT IS, THEREFORE ORDERED BY THE RAILROAD COMMISSION OF TEXAS from and after the effective date of this Order, and pursuant to the Rules and Regulations contained in the attached Appendix, all gas pipeline facilities and the transportation of gas within this State, except those facilities and that transportation of gas which are subject to the exclusive Federal jurisdiction under the Federal Natural Gas Pipeline Act of 1968, shall be constructed, maintained and operated in accordance with the Minimum Safety Standards known as 49 CFR Part 192, with amendments. Appendix "A" attached includes additional rules and regulations which are hereby adopted.

IT IS FURTHER ORDERED that since the safety code provided by the Order of the Commission in Gas Utilities Docket No. 422 is superseded by the safety code adopted herein, said Order is therefore rescinded.

IT IS FURTHER ORDERED that the Gas Utilities Director be, and he is, hereby specifically authorized and instructed to prepare, execute, authenticate, and transmit to the Secretary of Transportation of the United States all such certificates as are, from time to time, necessary or appropriate under the Federal Natural Gas Pipeline Act of 1968 to preserve to the greatest extent permitted by said Act exclusive State jurisdiction over gas pipeline facilities and the transportation of gas within this State.

IT IS FURTHER ORDERED that this cause be held open for such other and further orders as may be deemed necessary.

ENTERED AT AUSTIN, TEXAS, this 31st day of December, 1970.

RAILROAD COMMISSION OF TEXAS

(signed)
BEN RAMSEY, Chairman
BYRON TUNNELL, Commissioner

ATTEST:

(seal)

(signed)
George F. Singletary, Jr.
Acting Secretary, RRC

Rules and Regulations
Adopted by The Railroad Commission of Texas
Gas Utilities Docket No. 446

Appendix A

RULE 1. **DEFINITIONS.**

As Used in These Rules - -

(1) *Person* means any individual, firm, joint venture, partnership, corporation, association, state, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof;

(2) *Gas* means natural gas, flammable gas, or gas which is toxic or corrosive;

(3) *Transportation of gas* means the gathering, transmission or distribution of gas by pipeline or its storage within the State of Texas; except that it shall not include the gathering of gas in those rural locations which lie outside the limits of any incorporated or unincorporated city, town, village or any other designated residential or commercial area such as a subdivision, a business or shopping center, a community development, or any similar populated area which the Secretary of Transportation may define as a non-rural area.

(4) *Pipeline facilities* includes, without limitation, new and existing pipe, rights-of-way and any equipment, facility or building used in the transportation of gas or the treatment of gas during the course of transportation;

(5) *Gas company* means any person who owns or operates pipeline facilities used for the transportation of gas;

(6) *Commission* means the Railroad Commission of Texas.

RULE 2. **SAFETY CODE ADOPTED.**

Except with reference to pipeline facilities and the transportation of gas which are subject to the jurisdiction of the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A., Subsection 7 17 et seq., all gas pipeline facilities and the transportation of gas shall be subject to the provisions of 49 CFR Part 192, with amendments, promulgated by the Office of Pipeline Safety, Department of Transportation, and known as the Minimum Safety Standards, a copy of which is on file with the Secretary of the Commission.

RULE 3. **STANDARDS MINIMUM ONLY.**

The Minimum Safety Standards adopted in Rule 2 above establish minimum standards of accepted good practice. Nothing contained herein shall prevent the Commission, after an appropriate public hearing or investigation, from prescribing more stringent standards in individual situations.

RULE 4. **SPECIAL CIRCUMSTANCES.**

(1) In the event any gas company cannot determine to its satisfaction the standards applicable to special circumstances, it may, by written application, request the Commission for advice and recommendations, and in a special case, the Commission may authorize exemption from, or modification or temporary suspension of any of the provisions of the Minimum Safety Standards.

(2) In the event any gas company which is operating or shall hereafter operate pipeline facilities and

transport gas, some of which facilities and transportation are subject to the jurisdiction of this Commission and others of which are subject only to the jurisdiction of the Department of Transportation under the Natural Gas Pipeline Safety Act of 1968, notifies this Commission that it desires that all of its pipeline facilities and transportation of gas be subject to the exclusive jurisdiction of the Department of Transportation, the Director, Gas Utilities Division, may grant exemption from compliance with the safety Rules and Regulations of this Commission upon the statement, under oath, of an officer of such gas company that it will fully comply with the Federal Safety Rules and Regulations respecting its pipeline facilities and transportation of gas otherwise subject to the jurisdiction of this Commission.

RULE 5. **RETROACTIVITY.**

Nothing in these Rules and Regulations provided shall be applied retroactively to any existing installations insofar as its design, fabrication, installation, or estimated operating pressure is concerned, except as required by Regulations of the Office of Pipeline Safety, Department of Transportation.

RULE 6. **NO CIVIL LIABILITY.**

It is further provided that the Minimum Safety Standards as adopted herein shall not be so construed as to impose upon any gas company any civil liability for damages, which liability would not exist if said Code had not been adopted herein, nor to relieve any such liability which would have existed had such Code not been adopted herein.

RULE 7. **REPORTING OF ACCIDENTS.**

(1) In the event of a reportable accident, as defined hereinafter, upon a gas company's pipeline facilities, the company shall notify the Commission by telephone of said accident at the earliest practicable moment following discovery, and shall report, in writing, a summary of said accident within twenty (20) days after detection on forms supplied by the Department of Transportation. A reportable accident is hereby defined to be any fatality, or any personal injury requiring hospitalization, or any property damage exceeding $1,000.00 arising out of the transportation of gas.

(2) All written reports required by Part 191, Title 49, of the Code of Federal Regulations shall be submitted to the Commission in duplicate on forms supplied by the Department of Transportation, and one copy of the same shall, within ten (10) days of receipt thereof, and not later than February 15, for Annual Reports, be transmitted by the Director of the Gas Utilities Division to the Director, Office of Pipeline Safety, Department of Transportation, Washington, D. C. 20590.

RULE 8. **RECORDS.**

On and after the effective date of these Rules, each gas company operating gas facilities subject to the safety jurisdiction of this Commission shall comply with the provisions of the Minimum Safety Standards as amended, with respect to records required. In addition each gas company shall maintain records, as the Commission may require; adequate to show compliance or non-compliance with such Rules. All such records shall at reasonable times be kept open and readily available to the Commission and/or its Staff.

RULE 9. **INSPECTION AND MAINTENANCE PLANS.**

Each gas company operating a gas facility subject to the safety jurisdiction of this Commission shall file with the Commission a plan for Inspection and Maintenance of its facilities. If the Commission finds the plan is inadequate to achieve safe operation it shall require the plan to be revised. Thereafter, any and all changes in such plan of Inspection and Maintenance shall be filed with the Commission twenty (20) days before it becomes effective.

RULE 10. **ENFORCEMENT.**

The Staff Engineers of the Railroad Commission of Texas shall have responsibility for the enforcement of the provisions of these Rules. To this end, and subject to the approval of the Commission, they shall formulate a plan or program for periodic auditing of the books and records of gas companies operating in Texas on a random sampling basis, in order to satisfy the Commission that the provisions of such Rules are being fully complied with. The Staff Engineers shall investigate and report to the Commission in writing as to each instance in which it appears that such provisions have not been complied with, and shall tender their recommendations for bringing about prompt compliance.

As part of the Commission's over-all program of enforcement, the Staff Engineers shall include a plan for assuring compliance with these Rules in connection with upgrading or uprating of any existing installation. They shall, by periodic audit of gas company records, and by other means, and at least annually, verify that each gas company operating in Texas is in compliance with the Minimum Safety Standards and Gas Utilities Docket No. 446. They shall report to the Commission all cases of noncompliance promptly and recommend such action as they deem appropriate in the premises.

In the matter of the enforcement of the provisions of these Rules, each gas company operating in Texas, and its officers and employees shall make readily available to the Commission, or its Staff, any files, records, or other documents which shall be reasonably required in connection with the enforcement of any of the provisions of these Rules, or the investigation of any violations thereof.

Likewise, the plant, property, and facilities of such gas companies shall be made readily accessible to the Commission, and its Staff, in the administration and enforcement of these Rules in the investigation of violation or alleged violations of any of its provisions.

Such gas companies shall likewise provide to the Commission, or its Staff, such reports, supplemental data, and information as it shall from time to time reasonably require, in the administration and enforcement of the provisions of these Rules, or in the investigation of any violations or alleged violations of such Rules.

RULE 11. **REVISIONS OF THE MINIMUM SAFETY STANDARDS.**

Amendments, changes, and revisions of 49 CFR Part 192, known as the Minimum Safety Standards, shall be effective as a Rule or Regulation of this Commission unless specifically rejected by the Commission.

Gas Utilities
Substantive Rule 16 T.A.C. §7.22
Odorization Equipment, Odorization of Natural Gas and Odorant Concentration Tests

(a) **Definitions**

(1) The term *gas* when used in this rule means natural gas, flammable gas, or gas which is toxic or corrosive.

(2) The term *gas company* when used in this rule, shall mean and include every person, firm, corporation, or government entity, including but not limited to municipal corporations, gas utility as defined in TEX. REV. CIV. STAT. ANN. art. 6050, et seq. (1962) and public utility as defined in art. 1446c, Section 3(c)(3) (Supp. 1978), engaged in the activity of:

(A) Handling, storing, selling, or distributing for direct use by the ultimate consumer gas for private or commercial uses, or;

(B) Supplying gas by pipelines, or otherwise, for direct consumption in any public building or buildings, or by the general public, or;

(C) Operating a *transmission line* under the circumstances described in Title 49 Code of Federal Regulations, Part 192.625(b) and amendments thereto.

(3) *Farm tap odorizer* as used herein means a wick type odorizer serving a consumer or consumers using not more than 10 Mcf on an average day in any month.

(b) **Odorization of Gas**

(1) From and after the effective date of this rule, every gas company shall continuously odorize gas, by the use of a malodorant agent in accordance with the requirements set out hereinafter unless the gas shall contain a natural malodor as hereinafter described and provided for.

(2) Except to the extent required by Title 49 Code of Federal Regulations Part 192.625(b) odorization is not required for gas in:

(A) Underground or other storage, or;

(B) Gas used or sold primarily for use in natural gasoline extraction plants, recycling plants, chemical plants, carbon black plants, industrial plants, irrigation pumps, or;

(C) Gas used in lease and field operation or development or in repressuring wells.

(3) If gas is delivered for use primarily in one of the above exempted activities or facilities and is also used in one of those activities for space heating, refrigeration, water heating, cooking and other domestic uses, or if such gas is used for furnishing heat, or air conditioning for office or living quarters, such latter gas shall be odorized in accordance with these rules by the user.

(c) **General**

(1) A party, or the Commission staff, desiring Commission action

under this rule by an informal proceeding pursuant to TEX. REV. CIV. STAT. ANN. art. 6252-13a, Section 13e (Supp. 1978) shall make written application and furnish all necessary supporting data including necessary written waivers of hearing and issuance of a Proposal for Decision by an Examiner. The staff shall evaluate the application and make a recommendation to the Commission within a reasonable time following receipt of such application and all supporting information requested by the staff. If the staff approves the requested action, and the Commission agrees, the order granting the requested action may be signed without notice or hearing. If the staff or the Commission disapproves the application, the matter shall be docketed and processed in accordance with normal hearing procedures as set out in TEX. REV. CIV. STAT. ANN. art. 6252-13a, Section 13 (Supp. 1978).

(2) The rules In Re: *Odorization of Natural Gas or Liquefied Petroleum Gases, and Specifications for Design, Construction and Operation of Containers for Transporting, Storing or Dispensing Liquefied Petroleum Gases*, Tex. R. R. Comm'n, Gas Utilities Docket No. 122 (July 27, 1937) Rules 5, 6, and 7, and In Re: *Odorization of Natural Gas*, Tex. R. R. Comm'n, Gas Utilities Docket No. 183, (July 28, 1958) and all amendments thereto are hereby repealed as of the effective date of this rule.

(3) All reports and certificates filed under this rule shall be subject to the penalties provided in TEX. REV. CIV. STAT. Natural Resources Code Section 91.143 (Supp. 1978). (2-5 years in the penitentiary and $1,000 fine or both)

(d) **Odorization Equipment**

All gas companies shall utilize odorization equipment approved by the Railroad Commission of Texas as follows:

(1) Commercial manufacturers of equipment used for introducing malodorant required in this rule may submit plans and specifications of such equipment to the Railroad Commission of Texas for advance approval of standardized models and designs if the equipment is of a type commerically manufactured under accepted rules and practices of the industry.

(2) In the event a gas company plans to install commercially available gas odorization equipment which has been approved for use according to the procedure outlined in subsection (1) herein, prior to such installation the gas company shall submit to the Safety and Engineering Section of the Gas Utilities Division, the brand name, model number, location of the odorizer, and certification that the equipment will be installed and operated, according to the manufacturer's specifications. If an approved odorizer is moved from one location to another location, or if one type of approved odorizer is substituted for another, then the gas company must notify the Safety and Engineering Section of the Gas Utilities Division of the brand name of the odorizer to be moved, the model number, the old location, and the new location. No action shall be necessary on the part of the Safety and Engineering Section of the Gas Utilities Division when the above information, in proper order, is filed concerning approved odorization equipment except the assignment of a new identification number.

(3) All gas companies shall, before the installation of shop made or other odorization equipment not

commercially available or approved according to the procedure outlined in Subsections (1) and (2) herein, submit to the Railroad Commission plans and specifications in duplicate describing the equipment to be used for introducing the malodorant required by this rule. The Railroad Commission shall indicate its approval or disapproval of such plans by written Order.

(4) Any odorization equipment previously approved for use and in use on the effective date of this rule need not be reapproved under the terms of this rule.

(e) **Malodorants**

(1) The Gas Utilities Division shall maintain and promulgate approved lists of malodorants which shall meet the following criteria:

(A) The malodorant when blended with gas in the amount specified for adequate odorization of such gas shall not be deleterious to humans or to the materials present in a gas system; and shall not be soluble in water to a greater extent than 2 1/2 parts, by weight, of malodorant to 100 parts by weight, of water.

(B) The products of combustion from the malodorant shall be non-toxic to humans breathing air containing the products of combustion, and the products of combustion shall not be corrosive or harmful to the materials to which such products of combustion would ordinarily come in contact.

(C) The malodorant agent to be introduced in the gas, or the natural malodor of the gas, or the combination of the malodorant and the natural malodor of the gas, shall have a distinctive malodor so that when gas is present in air at a concentration of as much as 1 percent by volume the malodor is readily detectable by a person with a normal sense of smell.

(2) Injection of approved malodorant at the following rates is adequate to meet the criteria set forth in Sub-paragraph (1)(C) above:

(a) 0.3 pounds per MMCF for concentrated malodorants; and,

(b) 0.5 gallons per MMCF for dilute malodorant.

(3) On its own motion or at the request of any gas company or affected person, the Commission shall determine, after examination of any gas having a natural malodor, the necessary rate of injection of additional malodorant, if any, which shall be necessary to meet the requirements of Subsections (1) (C) and (2) herein as an exception to the approved injection rates.

(f) **Odorization Reports**

(1) Within thirty days after annual periods ending December 31, every gas company shall report to the Commission the following information for all odorizers except farm tap odorizers which require reporting pursuant to Section (g)(2) herein:

(A) The type of malodorant or malodorants introduced into the gas during each month or quarter of the annual period;

(B) The quantity of gas odorized by each malodorant or malodorants during each month or quarter of the annual period;

(C) The amount of malodorant injected per million cubic feet:

(2) In the event a gas company shall fail to timely file its odorization report or file an odorization report which on its face shows non-compliance, the gas company may be put on remedial status after written notice to it of such status and be required to report odorization monthly within twenty days after the close of each month or for such other interval and for such period of time as shall be necessary to remedy the deficiencies in its odorization report or reports.

(3) Gas companies which obtain gas into which malodorant has already been injected shall be exempt from the filing of odorization reports with respect to such gas.

(4) The first annual odorization report shall cover the period of time beginning January 1, 1979, and ending December 31, 1979. Until that time, quarterly odorization reports shall be filed 30 days after each calendar quarter stating the same information as required in Subsection (1) of this section.

(g) **Malodorant Test**

(1) Odorant concentration tests including room tests, and the use of malodorant concentration test meters, both according to the requirements and procedures heretofore promulgated by the Gas Utilities Division as Exhibit A hereto or other tests approved by the Commission and conducted in accordance with procedures approved and promulgated by the Commission, shall be conducted by every gas company of the gas supplied through its facilities and required to be odorized. Test points shall be distant from odorizing equipment, so as to be representative of the odorized gas in the system. Tests shall be performed at least once each calendar year, or at such other times as the Commission or staff may require. The results of these tests shall be reported to the Commission no later than Januay 31 of the following calendar year or at such other times as the Commission may require.

(2) Farm tap odorizers shall be exempt from the odorization testing requirements of Subsection (1) herein. Farm tap odorizers shall be checked, tested, and serviced at least annually according to the terms of a service and maintenance plan filed with and approved by the Commission. Gas companies having farm tap odorizers shall certify to the Commission on January 31 of each year that service and maintenance of each such odorizer was performed during the preceding twelve months ending December 31 and that each odorizer was found to be in good working condition, or if not, what remedial steps were taken to put each odorizer in good working condition.

(3) Gas companies which obtain gas into which malodorant has already been injected or gas which is considered to have a natural malodor and therefore do not odorize the gas themselves shall be required to conduct quarterly malodorant concentration tests and submit the results 30 days after semi-annual periods ending June 30 and 31.

Exhibit A

Procedure for Conducting Room Test to Determine Malodorant Concentrations

Testing of gas to determine its level of detectability by distinctive malodor may be accomplished by use of the room test method. The test must indicate that at the point of malodor detection the gas present in air was in concentrations of one percent by volume or less as described in Texas Railroad Commission Gas Utilities Division Substantive Rules 16 T.A.C. §7.22(c)(1)(c). The report of test results shall be reported on the form prescribed and promulgated by the Safety and Engineering Section and shall contain the following:

1. Odorizer name and location, the Railroad Commission individual odorizer identification number, if applicable, as listed on the odorization report.

2. Description of gas meter or method of measurement used.

3. Date test performed, hours, odorizer(s) tested, and distance from odorizer.

4. Malodorant name, type, injection rate (in pounds or gallons per Mmcf).

5. Test results showing gas meter reading point at which each of at least three (3) witnesses and one (1) test supervisor detected the presence of gas by malodor, converting the average of these (4) to percent of room volume.

6. Signatures of minimum required witnesses and supervisors described above.

Procedure for the Use of Malodorant Concentration Test Meters

Testing of gas to determine its level of detectability by distinctive malodor may be accomplished by commercially available malodorant concentration meters according to their operating instructions, and the results of such tests may be used in substitution for room tests prescibed in Texas Railroad Commission Gas Utilities Division Special Substantive Rule 16 T.A.C. §7.22(g)(1) at the option of the gas company. The report of test results shall be reported on the form prescribed and promulgated by the Safety and Engineering Section and shall contain the following:

1. Odorizer name and location, the Railroad Commission individual odorizer identification number, if applicable, as listed on odorization report.

2. Malodorant concentration meter make, model and range.

3. Date test performed, hour, odorizer(s) tested, and distance from odorizer.

4. Malodorant name, type, injection rate (in pounds or gallons per Mmcf).

5. Test results: showing meter reading when malodor first detected, percent gas in air and milliampere meter reading if applicable.

6. Signature of person performing the test.

Instructions for Compliance with Gas Utilities Substantive Rule 16 T.A.C. §7.22, Including Form Examples

Approved Malodorants and Odorization Equipment

Any gas company or activity as described in (b)(3) required to odorize natural gas, must notify the Commission of their requirement to do so thereby enabling the Commission to assign identification numbers to the odorization equipment and add the company representative to the mailing list for annual odorant reports.

In addition every gas company must use odorization equipment and malodorants approved by the Railroad Commission. Below is a list of commercially available and approved odorization equipment and malodorants.

Commercially Available Odorization Equipment Approved by the Railroad Commission For Use in the State of Texas

Brand Name	*Model Number*	*Type*
Williams	CD-3000	Drip
Williams	XSDSP-Series	Positive Displacement Pump-Liquid Injection
Williams	B-100-Series	Positive Displacement Bourdon Pump-Liquid Injection
Williams	B	Positive Displacement Pump-Liquid Injection
Peerless	42-203	Wick
Peerless	MP-200	Meter Drive-Liquid Injection
Peerless	MP-550	Meter Drive-Liquid Injection
Peerless	MP-1000	Meter Drive-Liquid Injection
Peerless	42-100	Bypass
Peerless	42-200	Wick
Peerless	MP Special	Positive Displacement Pump-Liquid Injection
Peerless	42-204	Wick
Peerless	42-208	Wick
Peerless	42-109.4	Bypass
Peerless	42-118.5	Bypass
Peerless	42-120	Bypass
Peerless	42-154	Bypass
Peerless	42-157	Bypass
King Tool	Standard 1-B	Absorption Bypass
King Tool	Standard 2-B	Absorption Bypass
King Tool	Standard 3-B	Absorption Bypass
King Tool	Standard 4-B	Absorption Bypass
King Tool	Standard 5-B	Absorption Bypass
King Tool	Standard 6-B	Absorption Bypass
King Tool	1-W	Wick
King Tool	3-W	Wick
Process Systems Inc.	POIS 100	Liquid Injection
Process Systems Inc.	POIS 300	Liquid Injection

The above list of odorizers are approved for use in the State of Texas and can be submitted with additional information listed in Gas Utilities Substantive Rule 16 T.A.C. §7.22(d)(1).

This list will be revised as manufacturers request and are granted approval of equipment submitted in accordance with Gas Utilities Substantive Rule 16 T.A.C. §7.22(d)(1).

This list contains only commercially available equipment. RRC approval on all other equipment will be recognized by entering the RRC/GUD Docket No. of the order issuing that approval in item 3 on the PS-25A form.

Malodorants Approved by the Railroad Commission For Use in the State of Texas

Name of Malodorant	*Manufacturer*	*Concentrate (C) or Dilute (D)*	*Weight per Gal. at 60° F.*
Captan	Natural Gas Odorizing	C	6.88 lb.
B. P. Captan	Natural Gas Odorizing	C	6.75 lb.
L. P. Captan	Natural Gas Odorizing	C	7.00 lb.
R. P. Captan	Natural Gas Odorizing	C	6.80 lb.
R. P. Captan (V)	Natural Gas Odorizing	C	6.76 lb.
T. B. Captan	Natural Gas Odorizing	C	6.82 lb.
Captan 99	Natural Gas Odorizing	C	6.88 lb.
D. L. Captan	Natural Gas Odorizing	D	6.00 lb.
C. L. Captan	Natural Gas Odorizing	D	6.00 lb.
C. S. Captan	Natural Gas Odorizing	C	8.32 lb.
C.S. - B.P. Captan No. 11	Natural Gas Odorizing	C	7.54 lb.
Captan 85	Natural Gas Odorizing	C	6.95 lb.
Captan 90	Natural Gas Odorizing	C	6.90 lb.
Gasniff	Natural Gas Odorizing	C	6.92 lb.
25% B. P. Captan (M. C. Captan)	Natural Gas Odorizing	D	5.80 lb.
Spotleak 1001	Pennwalt Corporation	C	6.80 lb.
Spotleak 1003	Pennwalt Corporation	C	6.80 lb.
Spotleak 1008	Pennwalt Corporation	C	6.80 lb.
Spotleak 1009	Pennwalt Corporation	C	6.76 lb.
Spotleak 1015	Pennwalt Corporation	D	6.70 lb.
Spotleak 1450	Pennwalt Corporation	C	6.80 lb.
Pennodorant 1005	Pennwalt Corporation	C	7.75 lb.
Pennodorant 1013	Pennwalt Corporation	C	8.33 lb.
Modified Spotleak 1009	Pennwalt Corporation	C	6.76 lb.
Spotleak Lot #1440	Pennwalt Corporation	C	6.80 lb.
Spotleak Lot #1007	Pennwalt Corporation	C	6.72 lb.
Scentinal F	Phillips Chemical Co.	C	6.79 lb.
Scentinal O	Phillips Chemical Co.	C	6.86 lb.
Scentinal E	Phillips Chemical Co.	C	6.77 lb.
Scentinal G (Con.)	Phillips Chemical Co.	C	7.04 lb.
Scentinal G (Dilute)	Phillips Chemical Co.	D	7.04 lb.
Scentinal D	Phillips Chemical Co.	C	6.70 lb.
Scentinal H-85	Phillips Chemical Co.	D	5.76 lb.
Scentinal S-20	Phillips Chemical Co.	C	6.80 lb.

Exception to the above:

As required in Rule 16, subsection (e)(3), gas companies or systems that obtain gas odorized by another company or system or gas that possesses a natural malodor shall file a written request for Commission approval for an exception to the approved injection rates.

For reporting purposes, systems receiving approval under subsection (e)(3) are assigned an RRC identification number for item 1 on the annual and semi-annual Form PS-8A.

Odorization Equipment Installation and/or Approval Form, PS-25

The PS-25 form is a multipurpose form for requesting approval of odorization equipment installations and/or relocations. Before an odorizer identification number can be issued, equipment must first be approved at the engineering level and then docketed for Commission approval. A copy of the PS-25 form will be returned upon approval, indicating the RRC identification number in item 6 and/or the docket number in item 7.

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
PIPELINE SAFETY SECTION

ODORIZATION EQUIPMENT INSTALLATION AND/OR APPROVAL FORM*

Applicant _____

Address: _____

City: _____ Zip: _____

FOR RRC USE ONLY (7)
Date Received: _____
Log No.: _____
Approval Date: _____
Docket No.: _____

Check the box which applies to your situation and refer to the applicable section.

X. ☐ A commercial manufacturer submitting plans and specifications for RRC approval. COMPLETE SECTION A ONLY. Sign form.

Y. ☐ Gas company submitting plans and specifications for approval of shop-made odorization equipment not previously approved for use by applicant only. COMPLETE SECTIONS A AND B. Sign form.

Z. ☐ Gas company submitting plans and specifications for approval of shop-made odorization equipment for commercial availability. COMPLETE SECTIONS A AND B. Sign form.

SECTION A

BRAND NAME: _____ MODEL NO.: _____ TYPE (See Item 3 on reverse side): _____

Attach to this form plans and specifications to include the following:

1. A detailed drawing of the odorizer, related piping, and valves used for standard installation.
2. Test data verifying the maximum flow rate (Mcf/day) at which the required injection rate will be adequately maintained and the injection rate for various flows.
3. The maximum operation pressure (design). Show calculations.
4. The actual working pressure. (Applies to Z. only)
5. Written standard installation instructions. (Include schematic if installation drawing is not clear.)

(See reverse side for Section B instructions.)

SECTION B

Gas Company Representative (1)

Street or P. O. Box

City State Zip Code Area Code Telephone #

Individual Odorizer Location	Odorizer Type	Proposed Installation Date-Mo/Yr	City, Area, System, or Facility Served
Location	(3)	(4)	(5)
County			RRC USE ONLY ID # (6)

I, _____ do certify that this equipment will be installed and operated by the manufacturer's specifications.

Sections A & B must sign form.

_____ Signature Date

_____ Type or Print Last Name and Title

Telephone _____ A/C _____ Number

RRC FORM PS-25
Rev. 11/84

* This form applies **only** to odorization equipment **not** previously approved by the Railroad Commission of Texas (See reverse side for details.)

Remember the following when completing this form:

- When installing a wick-type odorizer meeting the definition of a farm tap as stated in Rule 16(a)(3), a PS-9 form, to be filed along with the PS-25A is required to attain eligibility for the farm tap exemption from odorant injection reporting.
- Refer to tables for approved equipment and malodorants.
- Approved odorization equipment, other than commercially available equipment, will not be added to the Railroad Commission approved list, however, future installations of odorization equipment manufactured to the same specifications (unless that approval specified the use of this unit for a specific location only), will be recognized upon identification of the Docket Number of the approval in item 3 on the PS-25A form.
- When requesting approval of shop-made equipment, make sure all information requested under Section A on the face of the form is provided.

This form is to be used by anyone planning to install odorization equipment not previously approved by the Railroad Commission of Texas. Gas Utilities Substantive Rule 16 T.A.C. §7.22(d) states, "All gas companies shall utilize odorization equipment approved by the Railroad Commission of Texas . . ." Previously approved odorization equipment is listed under Commercially Available Odorization Equipment Approved by the Railroad Commission For Use in the State of Texas.

Gas companies planning to install previously approved odorization equipment are to notify the Commission by filing an Odorization Equipment Installation Form PS-25A.

SECTION B - INSTRUCTIONS

ITEM 1 This is the person responsible for the company odorizer(s) listed in (2). Give the mailing address, city, zip code, and telephone number where he may be contacted. This must be the person and address to whom all correspondence regarding the listed odorizers will be directed.

ITEM 2 List the location of the odorizer or odorizers that will be reported under the address in item 1. If there is no street address, indicate plant site, line ID number, mile pole, etc. **Be sure to indicate the county in which each odorizer is located.**

ITEM 3 Odorizer type as illustrated in Table below:

ODORIZER TYPE	CODE # FOR USE IN ITEM 4
Wick	1
Absorption bypass	2
Drip	3
Meter Drive Pump	4
Positive Displacement Pump	5
Other	6

NOTE: If the odorizer type is a "farm tap" as defined in 16 T.A.C. § 7.22(a)(3), complete Form PS—9, and return with this form.

ITEM 4 List the proposed installation date of each odorizer by month and year.

ITEM 5 List the city or section of a city, area, system or facility served (i.e., City of Raze, transmission line #6046, farm tap, dog house in plant B, etc.).

ITEM 6 FOR RRC USE ONLY.
Upon approval, a copy of this form will be returned indicating the RRC I.D. # for the specific location mentioned in item (5).

ITEM 7 FOR RRC USE ONLY.
Upon approval, a copy of this form will be returned indicating the docket number in this box. On future installations of the same odorizer, indicate this docket number in item (3) of the PS-25A form.

For additional forms, mail requests to:

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
P.O. DRAWER 12967
AUSTIN, TEXAS 78711-2967

Odorization Equipment Installation Form, PS-25A

The PS-25A form is the form used to request approval from the Railroad Commission for a proposed odorization equipment installation of odorization equipment previously approved by the Commission, and to notify the Commission of information required by Rule 16(d)(2).

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
PIPELINE SAFETY SECTION

ODORIZATION EQUIPMENT INSTALLATION FORM*

Applicant _____	FOR RRC USE ONLY (8)
Address: _____	Date Received: _____
City: _____ Zip: _____	Log No.: _____
	Approval Date: _____

Check the box which applies to your situation and refer to the applicable section.

Y. ☐ Filing to notify a change in existing equipment either through relocation or replacement.

Z. ☐ Gas company or "user" (See Rule 16 (b)(2)(3)) installing commercially available equipment on the RRC approved list or equipment previously approved through the GUD Docket System.

(See reverse side for instructions.)

Gas Company Representative (1)

Street or P. O. Box

City State Zip Code Area Code Telephone #

(2) Individual Odorizer Location	Brand Name Model # or Docket #	Odorizer Type	Proposed Installation Date - Mo/Yr	City, Area System or Facility Served
Location County	(3)	(4)	(5)	(6) RRC USE ONLY (7) ID #
Location County	(3)	(4)	(5)	(6) RRC USE ONLY (7) ID #

I, _____ do certify that this equipment will be installed and operated by the manufacturer's specifications.

_____
Signature Date

_____
Type or Print Last Name and Title

Telephone _____ _____
A/C Number

RRC FORM PS-25A
Rev. 11/84

* This form applies only to odorization equipment previously approved by the Railroad Commission of Texas. (See reverse side for details.)

Remember the following when completing this form:

- When installing a wick-type odorizer meeting the definition of a farm tap as stated in Rule 16(a)(3), a PS-9 form, to be filed along with the PS-25A, is required to attain eligibility for the farm tap exemption from odorant injection reporting.
- Refer to tables for approved equipment and malodorants.
- When requesting approval of shop-made equipment previously approved by the Commission, indicate the Gas Utilities Docket Number in item 3.

This form is to be used by anyone planning to install commercially available odorization equipment previously approved by the Railroad Commission of Texas. Previously approved odorization equipment is listed under Commercially Available Odorization Equipment Approved by the Railroad Commission For Use in the State of Texas.

Anyone planning to install odorization equipment not approved by the Railroad Commission is to apply for approval by submitting plans and specifications along with an Odorization Equipment Installation And/or Aproval Form, PS—25, prior to installation.

INSTRUCTIONS

ITEM 1 This is the person responsible for the company odorizer(s) listed in (2). Give the mailing address, city, zip code, and telephone number where he may be contacted. This must be the person and address to whom all correspondence regarding the listed odorizers will be directed.

ITEM 2 List the location of the odorizer or odorizers that will be reported under the address in Item (1). If there is no street address, indicate plant site, line ID number, mile pole, etc. **Be sure to indicate the county in which each odorizer is located.**

ITEM 3 Brand name and model number from RRC approved list. (If installing previously approved noncommercial equipment, provide docket number.)

ITEM 4 Odorizer type as illustrated in Table below:

ODORIZER TYPE	CODE # FOR USE IN ITEM 4
Wick	1
Absorption bypass	2
Drip	3
Meter Drive Pump	4
Positive Displacement Pump	5
Other	6

NOTE: If the odorizer type is a "farm tap" as defined in 16 T.A.C. § 7.22(a)(3), complete Form PS—9, and return with this form.

ITEM 5 List the installation date of each odorizer by month and year.

ITEM 6 List the city or section of a city, area, system or facility served (i.e., City of Raze, transmission line #6046, farm tap, dog house in plant B, etc.).

ITEM 7 FOR RRC USE ONLY.
Upon approval, a copy of this form will be returned indicating the RRC ID# for the specific location mentioned in item (5). If box "Y" is marked, indicate the current RRC ID# in this box (the number will remain the same).

ITEM 8 FOR RRC USE ONLY.

For additional forms, mail requests to:

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
P.O. DRAWER 12967
AUSTIN, TEXAS 78711-2967

Schedule of Service Maintenance for Farm Tap Odorizers - Form PS-9

Excerpt from Rule 16 (a), definition (3) *'Farm tap odorizer' as used herein means a wick type odorizer serving a consumer, or consumers, using not more than 10 MCF on an average day in any month.*

Odorization units meeting the definition above are exempt from the odorization testing requirements listed on the following pages if a *Schedule of Service and Maintenance* has been filed

FILE WITH
RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
ENGINEERING/SAFETY SECTION

-INSTRUCTIONS
REVERSE SIDE-

APPROVED SCHEDULE OF SERVICE AND MAINTENANCE
FOR FARM TAP ODORIZERS

(1) COMPANY NAME _____

(2) REP. I. D. # _____

(3) RRC ODORIZER I. D. #	(4) NAME OF MALODORANT	(5) CONCEN-TRATE OR DILUTE	(6) INSPECTION FREQUENCY	(7) INSPECTION PROCEDURE
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
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		C or D		
		C or D		
		C or D		

(CONTINUED – REVERSE SIDE)

CERTIFICATE:

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

If Submitting Multiple Copies – Sign First Copy Only

Signature _____ Date _____

Type or Print Name and Title _____

Telephone (Area Code) _____ Number _____

RRC FORM PS-9
Rev. 11/78

with the Commission. However, gas companies having farm tap odorizers must certify by January 31 of each year that each such odorizer was serviced and maintained in accordance with the previously filed Schedule (PS-9). This certification is accomplished by signing and returning the PS-8A form sent annually to each gas company having odorization responsibility.

The Schedule of Maintenance, Form PS-9 on this page, must be completed in detail for each farm tap. Follow the instructions for items 1-7 carefully. When submitting with a PS-25 or PS-25A form leave item #3 blank. This will be completed by Commission staff and a copy returned for your records.

(Continued from Other Side)

(3) RRC ODORIZER I. D. #	(4) NAME OF MALODORANT	(5) CONCEN-TRATE OR DILUTE	(6) INSPECTION FREQUENCY	(7) INSPECTION PROCEDURE
		C or D		
		C or D		
		C or D		
		C or D		
		C or D		
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INSTRUCTIONS: (1) Company Name
(2) Representative's Assigned I.D. Number
(3) Assigned RRC Odorizer Number (If filing with PS-25, leave blank
(4) Name of Malodorant, i.e., B.P. Captan, etc.
(5) Concentrate or Dilute - Circle correct symbol, i.e., Ⓒ or D
(6) Inspection Frequency – Minimum frequency is annually
(7) Inspection Procedure - Be definitive of normal inspection procedure and note all maintenance that is done.

Malodorant Injection Reports

For compliance with section (f)(1) of Rule 16 gas companies required to odorize (with the exception of farm taps) must complete the forms PS-8 (on this page) *quarterly*. Quarterly periods are January - March; April - June; July - September; October - December. These forms are to be *retained* in your company files. The *rate per mmcf each quarter will be transferred* onto the PS-8A form annually and submitted to the Railroad Commission by January 31 following each calendar year.

RETAIN FOR COMPANY FILE

FORM PS-8
Rev. 11/78

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
SAFETY AND ENGINEERING SECTION
QUARTERLY ODORIZATION REPORT

ODORIZATION REPORT FOR
QUARTER ENDING ____________

REP ID ________ ☐ 1 ☐ 2 ☐ 3 ☐ 4

PLEASE READ INSTRUCTIONS ON REVERSE SIDE BEFORE COMPLETING THIS FORM

(1) RRC ODORIZER ID	(2) PS-9	(3) NAME OF MALODORANT	(4) DILUTE OR CONCENTRATE	(5) AMOUNT INTRODUCED	(6) MMCF OF GAS ODORIZED	(7) RATE PER MMCF	(8) DATE REMOVED
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	
			C	Lbs		Lbs	
			D	Gals		Gals	

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

____
SIGNATURE DATE

____
TYPE OR PRINT NAME AND TITLE

TELEPHONE ________ ____________
AREA CODE NUMBER

The minimum acceptable injection rates for a concentrate malodorant is .3 lbs. per mmcf; for a dilute malodorant .5 gal. per mmcf.

Detailed instructions for completing the PS-8 form are on the back of the form.

INSTRUCTIONS

This quarterly Odorization Report Form PS--8, is to be retained for your company records and available for Commission inspection. The information in Item 7 of this form is to be transferred onto the "Annual Approved Odorant Information Results Form PS--8A", which will be issued by the Commission in December, 1979, and each succeeding December. Transfer the assigned RRC odorizer numbers from the computer printout received in December. Any additions or deletions to these numbers throughout the year will have to be added by you as we will mail these forms out on an annual basis only. We will, however, at your request send an updated computer printout of your Odorizer I. D. numbers. The following instructions explain how to complete each numbered item on the face of this form.

NOTE: Before installation of any odorization equipment, read Gas Utilities Substantive Rule 12.

IF the odorizer to be installed is commercially available and on the approved list, submit to the Safety and Engineering Section of the Gas Utilities Division, the brand name, model number, the location of odorizer, and certification of equipment installation and operation in accordance with the manufacturers specifications on RRC Form PS--25.

IF the odorizer is shop made or not commercially available, or approved according to Rule 12 (1) (2), submit to the Railroad Commission, with RRC Form PS--25, plans and specifications in duplicate describing the equipment to be used for introducing the malodorant required by Rule 12. The Railroad Commission shall indicate its approval or disapproval of such plans by written order.

ITEM 1. RRC ODORIZER ID. List your RRC assigned odorizer numbers. Do not enter any other information or make any marks in this space except to add or delete numbers from update computer printouts.

ITEM 2. PS--9. If the assigned odorizer ID number in ITEM 1 is for a wick type odorizer, applicable under the Farm Tap definition in Rule 12 of serving a consumer or consumers using not more than 10 MCF on an average day in any month, and is being serviced and maintained in accordance with an approved schedule (Form PS--9) on file with the Railroad Commission, mark an "X" in ITEM 2, then leave blank items 3, 4, 5, 6, and 7.

ITEM 3. NAME OF MALODORANT. Print name of malodorant used in the odorization of natural gas for the assigned odorizer.

ITEM 4. CONCENTRATE OR DILUTE. Circle C for concentrate or D for dilute and complete Items 5, 6, and 7 on the same line across.

ITEM 5. AMOUNT INTRODUCED. Enter the amount of malodorant introduced in lbs. if concentrate, gals. if dilute.

ITEM 6. MMCF OF GAS ODORIZED. Number of million cubic feet of gas odorized.

ITEM 7. RATE PER MMCF. Rate of lbs. of gals. of malodorant introduced per MMCF of natural gas odorized. Use the following formula:

$$\frac{\text{AMOUNT INTRODUCED IN LBS OR GALS (ITEM 5)}}{\text{MMCF OF GAS ODORIZED (ITEM 6)}}$$

ITEM 8. DATE REMOVED. If the assigned odorizer has been removed or discontinued, enter date in month/day/year format.
EXAMPLE: October 23, 1978 removal date is shown in Item 8 as 10/23/78.

READ THE CERTIFICATE, SIGN AND DATE THE REPORT, RETAIN IN COMPANY FILE. IN DECEMBER, TRANSFER INFORMATION IN ITEM 7 TO THE "ANNUAL APPROVED ODORANT INFORMATION RESULTS FORM (PS--8A)", IN ITEM 6, 7, 8, AND 9, AS APPLICABLE.

Malodorant Concentration Testing (No odorizers)

Rule 16, Subsection (g)(3), Malodorant Tests, states *Gas companies which obtain gas into which malodorant has already been injected or gas which is considered to have a natural malodor* and therefore do not odorize the gas themselves *shall be required to conduct quarterly malodorant concentration tests* and submit the results 30 days after *semi-annual* periods ending June 30 and December 31.

RETAIN FOR COMPANY FILE

-INSTRUCTIONS REVERSE SIDE-

RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
ENGINEERING/SAFETY SECTION
APPROVED ODORANT CONCENTRATION TEST FORM

ODORANT CONCENTRATION METER METHOD

1. RRC Odorizer I.D. _____
2. Location of Test _____
3. Distance from Odorizer _____
4. Test Date _____
5. Instrument Used _____
6. Serial No. _____
7. Test Time _____
8. Signature of Tester _____

Witnesses _____

_____

9. Odor Concentration Meter Test
[(B) x (D)] = _____ % Gas in Air
(Should be less than 1%)

(A) Odorant Concentration Meter Reading When Gas Odor Detected (Glass or Steel Float) _____

(B) % Gas in Air, Odorant Concentration Meter _____

(C) Specific Gravity of Gas Tested _____

(D) Correction Factor for Gravity _____

ROOM TEST METHOD

1. SIGNATURES OF TEST WITNESSES

_____

_____

_____

_____

_____

2. SIGNATURE OF TESTER

_____

3. METERED VOLUME OF GAS

_____

_____

_____

_____

_____

_____

METER READING
Beginning _____ Cubic Feet
Ending _____ Cubic Feet

(E) Volume of Test Room (L x W x H) _____ Cubic Feet

(F) Volume of Furniture [See (I)] _____ Cubic Feet

(G) Net Volume of Room (E–F) _____ Cubic Feet

(H) Average Metered Volume of Gas _____ Cubic Feet

4. Room Test (H÷G x 100) _____ % Gas in Air

(I) AVERAGE VOLUMES OF SPACE DISPLACED BY FURNITURE AND PEOPLE (CUBIC FEET)

1. Bed, Double	30	9. Divan, One Piece	20
2. Bed, Single	20	10. Divan Sectional	25
3. Buffet	20	11. Dresser	10
4. Chair, overstuffed	10	12. Radio, Table Model	1
5. Chest of Drawers	15	13. Radio, Console	6
6. Cedar Chest	10	14. Table, Dining	2
7. China Cabinet	10	15. T.V., Table Model	5
8. Desk	8	16. T.V., Console	10
		17. One Person	3

REMARKS: _____

_____

RRC FORM PS–6
Rev. 10/79

The malodorant concentration tests are to be made by either the room test or concentration test meter method as described in "Exhibit A" of Rule 16. RRC Form PS-6, on this page, is to be completed and retained in operators' files as a record of these quarterly tests. Test results (percent of gas in air) shall be transferred onto Form PS-8A at the specified semi-annual periods and filed with the Commission. (See Form PS8-A and instructions on following pages)

Malodorant Concentration Test (Odorizers in use)

As required by Rule 16 (g) (1) odorant concentration tests by room or meter method shall be conducted by every gas company of the gas supplied through its facilities and required to be odorized. Test points shall be distant from odorizing equipment, so as to be *representative of the odorized gas in the system.* Tests shall be performed at least *once* each calendar *year*, or at such other times as the Commission or staff may require. The results of these tests shall be reported to the Commission no later than January 31 of the following calendar year or at such other times as the Commission may require. RRC Form PS-6 is to be completed and retained by the operator on each test made. The test results, percent of gas in air at detection, are to be entered in item 10 (A) on the PS-8A for each odorizer. The PS-8A Form is a computer printed form,

INSTRUCTIONS FOR RRC FORM PS–6

APPROVED ODORANT CONCENTRATION TEST FORM

ODORANT CONCENTRATION METER METHOD

1. RRC Odorizers I.D. #(s) - - - numbers designated by the Commission for odorizer or odorizers being tested.
2. Location of Test.
3. Distance from odorizer - - - if this is a short distance, indicate why.
4. Test date.
5. Instruments used - - - house meter, odor concentration test meter including type and brand.
6. Serial Number.
7. Time of Test.
8. Signature of tester.

   (A) Odorant Concentration Meter Reading when gas odor detected.
   (B) % Gas in Odorant Concentration Meter - - - some meters require a conversion by use of curves supplied with the instrument.
   (C) Specific Gravity of Gas Tested if other than that specified by manufacturer.
   (D) Correction Factor for Specific Gravity if specific gravity is other than that specified by manufacturer.
9. Odorant Concentration Meter Method of Calculating % gas in air. The specific gravity of the gas being tested may affect the readout. To determine this, check with the manufacturer of the instrument being used. If gas with a specific gravity, other than that used in the calibration of the instrument, is being used, a correction factor may have to be applied. If so, the correction factor for specific gravity (D) will be multiplied by the % gas in odorant concentration meter (B) to get the correct % gas in air. This number must be less than 1% or your gas lacks sufficient odor.

ROOM TEST METHOD

1. Signatures of witness using a minimum of 3 witnesses.
2. Signature of tester.
3. Metered volume of gas at which point 3 witnesses and tester detected the gas odor.
   (E) Volume of Test Room - - - length x width x height gives cubic feet.
   (F) Volume of furniture, etc. - - - calculate by use of Table 1 or by measuring items not listed.
   (G) Net Volume of Room (E–F) - - - subtract volume calculated in F from volume calculated in E.
   (H) Average metered volume of gas at which point 3 witnesses and tester detected gas odor.
4. Room Test method of calculating % gas in air - - - divide (H) (average metered volume of gas) by (G) (net volume of room) and multiply by 100 to get % gas in air. This number must be less than 1% or your gas lacks sufficient odor.

* This form will not be filed with the Commission. It will be kept on file in your office for inspection by our staff engineers. The results of this test will be compiled on RRC Form PS–8A for each calendar year, and submitted to the Railroad Commission of Texas.

which shall be mailed to each gas operator identified with odorization responsibility in December of each year.

Blank Forms (PS-25, PS-25A, PS-6, PS-9 and PS-8) are available through written or telephonic correspondence with:

Railroad Commission of Texas
Gas Utilities Division
Pipeline Safety Section
P.O. Drawer 12967
Austin, Texas 78711
(512) 475-0461

The PS-8A form illustrated herein is the form used for filing data required by Rule 16 with the Railroad Commission. As explained previously, operators are required to make proper tests, maintain proper records and transfer test results as instructed onto the appropriate spaces on the PS-8A at semi-annual and annual periods. This form is three-dimensional.

Farm tap odorizers with an adequate Schedule of Service and Maintenance on file with the Commission are identified with an "x" in item 2 (PS-9). The annual certification required by Rule 16 for farm tap odorizers is accomplished by an operators' signature on this form.

Odorized systems without actual odorization equipment are identified by an "x" in item 3 (ODR). These systems are required to file the PS-8A semi-annually. The only applicable sections are items 10 (A) (B) (C) and (D).

Instructions on all odorizers listed in item (1) not having an "x" in item (2) or (3) require the completion of items (4), (6), (7), (8), (9) and 10 (A) plus signature of responsible party.

Additional detailed instructions are on the back of each form.

FILE WITH RAILROAD COMMISSION OF TEXAS
GAS UTILITIES DIVISION
SAFETY AND ENGINEERING SECTION

APPROVED ODORANT INFORMATION ANNUAL RESULTS FORM

FORM PS-8A
REV. 3/79

ODORIZATION REPORT
FOR YEAR ENDING ____________

REP ID ____________

PLEASE READ INSTRUCTIONS ON REVERSE SIDE BEFORE COMPLETING THIS FORM

(1) RRC ODORIZER	(2) PS-9	(3) ODR	(4) NAME MALODORANT	(5) C or D	RATE PER MMCF PER QUARTER (6) 1st	(7) 2nd	(8) 3rd	(9) 4th	(10) ODOR CONC. TEST A	B	C	D	(11) DATE REMOVED
				C Lbs									
				D Gals									
				C Lbs									
				D Gals									
				C Lbs									
				D Gals									
				C Lbs									
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				C Lbs									
				D Gals									

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete, to the best of my knowledge.

______________________________ SIGNATURE ______ DATE

______________________________ TYPE OR PRINT NAME AND TITLE

TELEPHONE ________ AREA CODE ____________ NUMBER

INSTRUCTIONS

This Annual Approved Odorant Information Results Form PS-8A is to be filed in Compliance with Rule 12(f) & (g) covering "Odorization Reporting Requirements." The form contains the preprinted odorizer identification numbers previously assigned by the Railroad Commission of Texas. The following instructions explain how to complete each numbered item on the face of the form. **NOTE: Before installation of any odorization equipment** submit to the Railroad Commission of Texas information as required by Rule 12(d) on RRC Form PS-25.

ITEM 1 RRC odorizer ID. The preprinted assigned number. Do not enter any information or make any marks in this space.

ITEM 2 PS-9. If the assigned odorizer ID number in Item 1 is for a "farm tap" odorizer as described in Rule 12(a) (3) and is being serviced ad maintained in accordance with an approved schedule (Form PS-9) on file with the Railroad Commission, and there is an "X" in Item 2, then leave blank Items 3, 4, 5, 6, 7, 8, 9, 10, and 11. Sign and return the form and this will be accepted as certification required by Rule 12(g) (2). Any remedial action necessary for an odorizer functioning inadequately should be in letter format attached to this certification.

ITEM 3 Odor. Gas contains sufficient malodor either naturally or chemically. If there is an "X" in Item 3 complete only Items 10 A, B, C, and D, required by Rule 12(g) (3). **All companies with an "X" will receive this form semi-annually, December and June.**

ITEM 4 Name of malodorant. Print name of Malodorant used in the odorization of natural gas for the assigned number.

ITEM 5 Concentrate or dilute. Circle C for concentrate and D for dilute and complete Items 6, 7, 8, and 9 of the same line straight across: **for concentrate report in lbs. and for dilute, report in gals.**

ITEMS 6 7, 8, 9 1st, 2nd, 3rd & 4th Quarterly Injection Rate. These numbers should be on RRC Form PS-8 in your files. Transfer the injection rate to the applicable quarter.

ITEM 10 Odor concentration test results. This is % gas in air at detection. These numbers should be on RRC Form PS-6 in you files. Transfer the applicable number to 10A. If your gas is received naturally odorized or already odorized and you have an "X" in column 3, you must have test results for 10A, B, C & D as required by Rule 12(g) (3), on your December report, and A & B on your June report. Enter percent to 2 decimal places. Examples: ½ of 1% gas in air at detection is shown as .50 or 9/10 gas in air at detection is shown as .90.

ITEM 11 Date removed. If the assigned odorizer has been removed or discontinued, enter the date of removal or discontinuance, enter date in month/date/year format. Example: October 23, 1978 date is shown in Item 11 as 10/23/78.

If any changes are required, attach a letter describing nature of change and return.

Certificate

1. Read the certificate, sign and date the report.
2. Print the telephone number including the area code.
3. Return this report before January 31 of the following calendar year of intended use to:

Railroad Commission of Texas
Gas Utilities Division
P. O. Drawer 12967
Austin, Texas 78711

Railroad Commission of Texas
Gas Utilities Division

In Re: Development of Written Procedures for Handling Leak Complaints — **Gas Utilities Docket No. 484**

Order

After due notice the Commission on August 22, 1972, heard testimony from representatives of persons owning or operating gas pipeline facilities, with regard to the adoption of a requirement for development of written procedures for handling leak complaints.

WHEREAS, the authority of the Commission to regulate gas pipeline facilities and the transportation of gas was clarified through the adoption by the 61st Legislature of Article 6053-1, RCS of Texas; and

WHEREAS, the Commission issued Gas Utilities Docket No. 446; and

WHEREAS, Gas Utilities Docket No. 446, Rule 3 gives the Commission authority to prescribe more stringent standards; and

WHEREAS, the Commission has determined that public safety requires the adoption of written procedures for handling leak complaints.

IT IS, THEREFORE, ORDERED BY THE RAILROAD COMMISSION OF TEXAS that from and after the effective date of this order, each distribution company shall have written procedures which shall include as a minimum the following:

1. Provision for receiving leak complaints and/or reports on a 24 hours, 7 day per week basis.

2. Provision requiring written record of all calls received and actions taken.

3. Provision requiring supervisory personnel to review calls received and actions taken to insure no hazardous conditions exist at the close of the work day.

4. Provision for training and equipping personnel used in the investigation of leak complaints and/or reports.

5. Provision for locating source of leak and determining degree of hazard involved.

6. Chain of command for service personnel to follow if assistance is required in determining degree of hazard.

7. Instructions to be issued by service personnel to customer and/or the public as necessary after leak is located and degree of hazard determined.

IT IS FURTHER ORDERED that the written procedures required by this Order be filed with the Commission within 30 days after the effective date of this Order.

IT IS FURTHER ORDERED that this cause be held open for such other and further orders as may be deemed necessary.

ENTERED AT AUSTIN, TEXAS, this 30th day of January, 1973.

RAILROAD COMMISSION OF TEXAS

(signed)
JIM C. LANGDON, Chairman
BYRON TUNNELL, Commissioner
BEN RAMSEY, Commissioner

ATTEST:
(Seal)

(signed)
George F. Singletary, Jr.
Secretary, RRC.

COX ACT
NATURAL GAS

Art. 6050. **CLASSIFICATION.**

Sec. 1. In this article, "person" means an individual, company, or private corporation, or their lessees, trustees, and receivers. In Articles 6050-6066, Revised Civil Statutes of Texas, 1925, as amended, "gas utility," "public utility," or "utility" means a person owning, managing, operating, leasing or controlling within this State any pipe lines, plant, property, equipment, facility, franchise, license, or permit for either one or more of the following kinds of business:

(a) Transporting, conveying, distributing or delivering natural gas: (1) for public use or service for compensation; (2) for sale to municipalities or persons or companies, in those cases referred to in Subsection (c) hereof, engaged in distributing or selling natural gas to the public; (3) for sale or delivery of natural gas to any person operating under franchise or a contract with any municipality or other legal subdivision of this State; or, (4) for sale or delivery of natural gas to the public for domestic or other use.

(b) Owning or operating or managing a pipe line for the transportation or carriage of natural gas, whether for public hire or not, if any part of the right of way for said line has been acquired, or is hereafter acquired by the exercise of the right of eminent domain.

(c) Producing or purchasing natural gas and transporting or causing the same to be transported by pipe lines to or near the limits of any municipality in which said gas is received and distributed or sold to the public by another public utility or by said municipality, in all cases where such business is in fact the only or practically exclusive agency of supply of natural gas to such utility or municipality, is hereby declared to be virtual monopoly and a business and calling affected with a public interest, and the said business and property employed therein within this State shall be subject to the provisions of this law and to the jurisdiction and regulation of the Commission as a gas utility.

(d) No person shall be deemed to be a "gas utility," "public utility," or "utility" solely because such person is an affiliate of such an entity.

(e) Every such gas utility is hereby declared to be affected with a public interest and subject to the jurisdiction, control and regulation of the Commission as provided herein.

Sec. 2. Provided, however, that the act or acts of transporting, delivering, selling or otherwise making available natural gas for fuel, either directly or indirectly, to the owners of irrigation wells or the sale, transportation or delivery of natural gas for any other direct use in agricultural activities shall not be construed within the terms of this law as constituting any person as a "gas utility," "public utility," or "utility" as hereinabove defined so as to make such person subject to the jurisdiction, control and regulation of the Commission as a gas utility.

Sec. 3. The natural gas made available under the provisions of this Act shall be used exclusively for pumping water for farm and other agricultural purposes in order for the person furnishing such natural gas to qualify for the exemption provided by Section 2 of this article. The provisions of this Act shall be considered only as cumulative of other laws and shall not have the effect of repealing or amending any substantive or statutory law except as herein specifically provided.

Sec. 4. (a) Except as provided by Section 1(b) of this article, the terms "gas utility," "public utility," and "utility" do not include a person who certifies to the Commission that the person transports natural or synthetic gas, whether for sale, for hire, or otherwise, solely from in or within the vicinity of the field or fields where produced:

(1) to a gas processing plant or treating facility, or from the outlet of such plant or treating facility to:

(A) a person at or within the vicinity of such plant or treating facility; or

(B) anyone described in (2) or (3);

(2) to another person for transportation or sale in interstate commerce; or

(3) to another person in or within the vicinity of the field or fields where produced for transportation or sale in intrastate commerce.

(b) A person who makes deliveries or sales for lease use, compressor fuel, processing plant fuel, or similar uses; deliveries or sales pursuant to lease or right-of-way agreements; or deliveries or sales in or within the vicinity of the field where produced or at a processing plant outlet does not become a "gas utility," "public utility," or "utility" by virtue of such transaction. However, the terms "gas utility," "public utility," and "utility" include a pipeline which transmits or distributes to other end users of gas, or which makes city-gate deliveries for local distribution, but does not include a person that qualifies for the exemption provided by Section 2 of this article.

Art. 6051. **MAY ENJOIN GAS PIPE LINE.**

The operation of gas pipe lines for buying, selling, transporting, producing or otherwise dealing in natural gas is a business which in its nature and according to the established method of conducting the business is a monopoly and shall not be conducted unless such gas pipe line so used in connection with such business be subject to the jurisdiction herein conferred upon the Commission. The Attorney General shall enforce this provision by injunction or other remedy.

Art. 6052. **UTILITY OFFICE.**

Every gas utility as defined herein shall have an office in one of the counties of this State in which its property or some part thereof is located and shall keep in said office all books, accounts, papers, records, vouchers and receipts which the Commission shall require. No books, accounts, papers, records, receipts, vouchers or other data required by the Commission to be so kept shall be at any time removed from this State except upon such conditions as the Commission may prescribe.

Art. 6053. **REGULATION OF UTILITIES.**

Rates; rules and regulations

Sec. 1. The Commission after due notice shall fix and establish and enforce the adequate and reasonable price of gas and fair and reasonable rates of charges and regulations for transporting, producing, distributing, buying, selling, and delivering gas by such pipe lines in this State; and shall establish fair and equitable rules and regulations for the full control and supervision of said gas pipe lines and all their holdings pertaining to the gas business in all their relations to the public, as the Commission may from time to time deem proper; and establish a fair and equitable division of the proceeds of the sale of gas between the companies transporting or producing the gas and the companies distributing or selling it;

and prescribe and enforce rules and regulations for the government and control of such pipe lines in respect to their gas pipe lines and producing, receiving, transporting, and distributing facilities; and regulate and apportion the supply of gas between towns, cities, and corporations, and when the supply of gas controlled by any gas pipe line shall be inadequate, the Commission shall prescribe fair and reasonable rules and regulations requiring such gas pipe lines to augment their supply of gas, when in the judgment of the Commission it is practicable to do so; and it shall exercise its power, whether upon its own motion or upon petition by any person, corporation, municipal corporation, county, or Commissioners precinct showing a substantial interest in the subject, or upon petition of the Attorney General, or of any County or District Attorney in any county wherein such business or any part thereof may be carried on.

Submetering in mobile home parks

Sec. 1a. Notwithstanding any law to the contrary, the Commission shall promulgate rules, regulations, and standards under which any owner, operator, or manager of a mobile home park may purchase natural gas through a master meter for delivery from such master meter to mobile home units within the mobile home park through individual submeters at each mobile home unit. Such rules and regulations shall require (a) that the owner, operator, or manager of a mobile home park shall not deliver natural gas for sale or resale for profit and (b) that the mobile home park shall maintain adequate records in connection with such submetering and shall make the records available for inspection by the mobile home resident during reasonable business hours.

Malodorants, investigation and regulation

Sec. 2. In addition to the duties and powers of the Commission hereinabove set forth, it is empowered and it shall be its duty to investigate the use of malodorants by persons, firms, or corporations engaged in the business of handling, storing, selling, or distributing natural and liquefied petroleum gases, including butane and other odorless gases, for private or commercial uses, or supplying the same by pipe lines or otherwise, to any public building or buildings, or to the general public, and the Commission is empowered to require such persons, firms, or corporations to odorize such gas by the use of a malodorant agent of such character as to indicate by a distinctive odor the presence of gas; such malodorant agent so required to be used, however, shall be non-toxic and non-corrosive and not harmful to leather diaphrams in gas equipment, the method of its use and containers and equipment to be used in connection therewith to be under the direction of and as approved by the Railroad Commission of Texas; the Commission having full power and authority to prescribe such rules and regulations as in its wisdom may be deemed necessary to carry out the purposes of this Act. Nothing herein contained shall apply to gas transported out of the State of Texas.

Art. 6053-1. TRANSPORTATION OF GAS AND GAS PIPELINE FACILITIES; SAFETY STANDARDS.

(A) For the purpose of providing state control over safety standards and practices applicable to the transportation of gas and all gas pipeline facilities within the borders of this state to the maximum degree permissible under the federal Natural Gas Pipeline Safety Act of 1968 (49 U.S.C.A. § 1671 *et seq.*), the Railroad Commission of Texas is hereby expressly granted the power to describe or adopt by regulation safety standards for all such transportation of gas and gas pipeline facilities which are not subject to exclusive federal control, to require record maintenance and reports and to inspect records and facilities to determine compliance with such safety standards, and, from time to time, to make

certifications and reports and to take any other requisite action in accordance with Section 5(a) of the Natural Gas Pipeline Safety Act of 1968.

(B) All terms employed in this Article which are defined in the Natural Gas Pipeline Safety Act of 1968 shall have the definition prescribed therein.

(C) The Attorney General is authorized, on behalf of the Railroad Commission, to enforce said safety standards by injunction restraining violations thereof (including the restraint of transportation of gas or the operation of a pipeline facility). Any violation of such safety standards shall further be subject to a civil penalty, payable to the State of Texas, in an amount not to exceed $1,000 for each such violation for each day that such violation persists, except that the maximum civil penalty shall not exceed $200,000 for any related series of violations. Any such civil penalty may be compromised by the Attorney General in consideration of the appropriateness of the penalty to the size of the business of the person charged, the gravity of the violation, and the good faith of the person charged in attempting to achieve compliance after notification of violation.

(D) Nothing in this Article shall be construed to reduce, limit or impair any power heretofore vested by law in any incorporated city, town or village.

Art. 6053-2. **ADMINISTRATIVE PENALTY.**

(a) A person who violates Article 6053 1, Revised Statutes, or safety standards or regulations relating to transportation of gas and gas pipeline facilities adopted under that article may be assessed a civil penalty by the Railroad Commission of Texas.

(b) The penalty may not exceed $10,000 for each violation. Each day a violation continues may be considered a separate violation for purposes of penalty assessments.

(c) In determining the amount of the penalty, the railroad commission shall consider the person's history of previous violations of this article, the seriousness of the violation, and any hazard to the health or safety of the public.

(d) A civil penalty may be assessed only after the person charged with a violation described under Section (a) of this article has been given an opportunity for a public hearing.

(e) If a public hearing has been held, the railroad commission shall make findings of fact, and it shall issue a written decision as to the occurrence of the violation and the amount of the penalty that is warranted, incorporating, when appropriate, an order requiring that the penalty be paid.

(f) If appropriate, the railroad commission shall consolidate the hearings with other proceedings under this article.

(g) If the person charged with the violation fails to avail himself of the opportunity for a public hearing, a civil penalty may be assessed by the railroad commission after it has determined that a violation did occur and the amount of the penalty that is warranted.

(h) The railroad commission shall then issue an order requiring that the penalty be paid.

(i) On the issuance of an order finding that a violation of this article has occurred, the railroad commission shall inform the person who is found in violation of the amount of the penalty within 30 days.

(j) Within the 30-day period immediately following the day on which the decision or order is final as provided in Section 16(c), Administrative Procedure and Texas Register Act (Article 6252 13a, Vernon's Texas Civil Statutes), the person charged with the penalty shall:

(1) pay the penalty in full; or

(2) if the person seeks judicial review of either the amount of the penalty or the fact of the violation, or both:

(A) forward the amount to the commission for placement in an escrow account; or

(B) in lieu of payment into escrow, post with the commission a supersedeas bond in a form approved by the commission for the amount of the penalty, such bond to be effective until all judicial review of the order or decision is final.

(k) If through judicial review of the decision or order it is determined that no violation occurred or that the amount of the penalty should be reduced or not assessed, the commission shall, within the 30 day period immediately following that determination, if the penalty has been paid to the commission, remit the appropriate amount to the person, with accrued interest, or where a supersedeas bond has been posted, the commission shall execute a release of such bond.

(l) Failure to forward the money to the railroad commission or post bond within the time provided by Section (j) of this article results in a waiver of all legal rights to contest the violation or the amount of the penalty.

(m) Civil penalties owed under this article may be recovered in a civil action brought by the attorney general at the request of the railroad commission.

Art. 6054. **ORDERS, ETC., REVIEWED.**

All orders and agreements of any company or corporation, or any person or persons controlling such pipe lines establishing and prescribing prices, rates, rules and regulations and conditions of service, shall be subject to review, revision and regulation by the Commission on hearing after notice as provided for herein to the person, firm, corporation, partnership or joint stock association owning or controlling or operating the gas pipe line affected.

Art. 6055. **TO REFUND EXCESS CHARGES.**

If any rate or charge for gas or for service or for meter rental or any other purpose pertaining to the operation of said business shall be made or promulgated by any person, firm or corporation owning or operating any gas pipe line, or in the event of an inadequate supply of gas or inadequate service in any respect, and complaint against same shall be filed by any person authorized by the preceding article to file such petition and such complaint is sustained in whole or in part, all persons and customers of said gas pipe line shall have the right to reparation or reimbursement of all excess in charges so paid over and above the proper rate or charge as finally determined by the Commission from and after the date of the filing of such complaint.

Art. 6056. **OPERATOR'S REPORTS.**

The Commission may require of all persons or corporations operating, owning or controlling such gas pipe lines sworn reports of the total quantities of gas distributed by such pipe lines and of that held by them in storage, and also of their source of supply, the number of wells from which they draw their supply, the amount of pressure maintained, and the amount and character and description of the equipment employed, and such other matters pertaining to the business as the Commission may deem pertinent.

Art. 6057. **DISCRIMINATION.**

No such pipe line public utility shall discriminate in favor of or against any person, place or corporation, either in apportioning the supply of natural gas or in its charges therefor; nor shall any such utility directly or indirectly charge, demand, collect or receive from any one a greater or less compensation for any service rendered than from another for a like and contemporaneous service; provided this shall not limit the right of the Commission to prescribe different rates and regulations for the use of natural gas for manufacturing and similar purposes, or to prescribe rates and regulations for service from or to other or different places, as it may determine.

Art. 6057a. **DISCRIMINATION.**

No pipe line public utility, as such utility is defined in the laws of this State governing the production and delivery of natural gas, shall discriminate in favor of or against any person, place or corporation, either in apportioning the supply of natural gas or in its charges therefor; nor shall any such utility directly or indirectly charge, demand, collect or receive from any one a greater or less compensation for any service rendered than from another for a like and contemporaneous service; provided this shall not limit the right of the Railroad Commission to prescribe different rates and regulations for the use of natural gas for manufacturing and similar purposes or to prescribe rates and regulations for service from or to other or different places, as it may determine.

Art. 6057b. **PENALTY FOR VIOLATION OF LAW.**

Any owner, officer, director, agent or employee of any person, firm or corporation owning, operating or controlling gas pipe lines of such utility mentioned in the preceding article, who shall willfully violate any provision of the statutes of this State governing such utility, including the preceding article, shall be fined not less than fifty nor more than one thousand dollars, and may in addition thereto be imprisioned in jail not less than ten days nor more than six months.

Art. 6058. **APPEAL FROM CITY CONTROL.**

When a city government has ordered any existing rate reduced, the gas utility affected by such order may appeal to the Commission by filing with it on such terms and conditions as the Commission may direct, a petition and bond to review the decision, regulation, ordinance, or order of the city, town or municipality. Upon such appeal being taken the Commission shall set a hearing and may make such order or decision in regard to the matter involved therein as it may deem just and reasonable. The Commission shall hear such appeal *de novo*. Whenever any local distributing company or concern, whose rates have been fixed by any municipal government, desires a change of any of its rates, rentals or charges, it shall make its application to the municipal government where such utility is located and such municipal government shall determine said application within sixty days after presentation unless the determination thereof may be longer deferred by agreement. If the municipal government should reject such application or fail or refuse to act on it within said sixty days, then the utility may appeal to the Commission as herein provided. But said Commission shall determine the matters involved in any such appeal within sixty days after the filing by such utility of such appeal with said Commission or such further time as such utility shall in writing agree to, but the rates fixed by such municipal government shall remain in full force and effect until ordered changed by the Commission.

Art. 6059. **APPEAL FROM ORDERS.**

If any gas utility or other party at interest be dissatisfied with the decision of any rate, classification, rule, charge, order, act or regulation adopted by the Commission, such dissatisfied utility or party may file a petition setting forth the particular cause of objection thereto in a court of competent jurisdiction in Travis County against the Commission as defendant. Said action shall be tried and determined as other civil causes in said court. Either party to said action may have the right to appeal; and said appeal shall be at once returnable to the appellate court, and said action so appealed shall have precedence in said appellate court of all causes of a different character therein pending. If the court be in session at the time such right of action accrues, the suit may be filed during such term and stand ready for trial after ten days notice. In all trials under this article the burden of proof shall rest upon the plaintiff, who must show by clear and satisfactory evidence that the rates, regulations, orders, classifications, acts or charges complained of are unreasonable and unjust to it or them.

Art. 6060. **UTILITY TAX.**

Every gas utility subject to the provisions of this subdivision on or before the first day of January and quarterly thereafter, shall file with the Commission a statement, duly verified as true and correct by the president, treasurer or general manager if a company or corporation, or by the owner of one of them if an individual or copartnership, showing the gross receipts of such utility for the quarter next preceding or for such portion of said quarterly period as such utility may have been conducting any business, and at such time shall pay into the State Treasury at Austin a sum equal to one-fourth of one per cent of the gross income received from all business done by it within this State during said quarter.

Art. 6061. **REPORT TO GOVERNOR.**

The Commission shall on December 1st of each year make a full detailed report to the Governor, who shall transmit the same to the next succeeding session of the Legislature, showing:

1. The proceedings of said Commission to such time with respect to the gas utilities defined herein.

2. The receipts of gross income taxes from all sources, indicating the sources.

3. The expenditures made under and in accordance with this subdivision, the nature of such expenditures, including in addition to other items of expenditures, the names, titles, nature of employment, salaries of and payments made to all persons employed for any purpose under the terms of this subdivision with statement of traveling and other expenses incurred by each of said persons and approved by the Commission.

Art. 6062. **PENALTIES.**

Any public utility as herein defined violating any provision of this subdivision or failing to perform any duty herein imposed or to comply with any valid order of the Commission when not stayed or suspended by order of the court, shall be subject to a penalty payable to the State of not less than one hundred nor more than one thousand dollars for each offense, each violation to constitute a separate offense, and each day that such failure continues shall constitute a separate offense. An additional penalty of a like amount together with reasonable attorney's fees may also be recoverable by and for the use of any person, corporation or association of persons against whom there shall have been unlawful

discrimination as herein defined; such suit to be brought in the name of and for the use of the party aggrieved.

Art. 6062A. **ADMINISTRATIVE PENALTY.**

(a) If a public utility as defined by Article 6050, Revised Statutes, violates this subdivision and the violation results in pollution of the air or water of this state or poses a threat to the public safety, the public utility may be assessed a civil penalty by the railroad commission. For purposes of this article, a public utility is considered to have violated this subdivision if it fails to perform a duty imposed by this subdivision, or fails to comply with a valid order of the Railroad Commission of Texas.

(b) The penalty may not exceed $10,000 a day for each violation. Each day a violation continues may be considered a separate violation for purposes of penalty assessments.

(c) In determining the amount of the penalty, the railroad commission shall consider the public utility's history of previous violations of this subdivision, the seriousness of the violation, and any hazard to the health or safety of the public.

(d) A civil penalty may be assessed only after the public utility charged with a violation described under Section (a) of this article has been given an opportunity for a public hearing.

(e) If a public hearing has been held, the railroad commission shall make findings of fact, and it shall issue a written decision as to the occurrence of the violation and the amount of the penalty that is warranted, incorporating, when appropriate, an order requiring that the penalty be paid.

(f) If appropriate, the commission shall consolidate the hearings with other proceedings under this chapter.

(g) If the public utility charged with the violation fails to avail itself of the opportunity for a public hearing, a civil penalty may be assessed by the commission after it has determined that a violation did occur and the amount of the penalty that is warranted.

(h) The commission shall then issue an order requiring that the penalty be paid.

(i) On the issuance of an order finding that a violation has occurred, the commission shall inform the public utility charged within 30 days of the amount of the penalty.

(j) Within the 30 day period immediately following the day on which the decision or order is final as provided in Section 16(c), Administrative Procedure and Texas Register Act (Article 6252 13a, Vernon's Texas Civil Statutes), the public utility charged with the penalty shall:

(1) pay the penalty in full; or

(2) if the public utility seeks judicial review of either the amount of the penalty or the fact of the violation, or both:

(A) forward the amount to the railroad commission for placement in an escrow account; or

(B) in lieu of payment into escrow, post a supersedeas bond with the railroad commission under the following conditions. If the decision or order being appealed is the first final railroad commission decision or order assessing any administrative penalty against the public utility, the railroad commission shall accept a supersedeas bond. In the case of appeal of any subsequent decision or order

assessing any administrative penalty against the public utility, regardless of the finality of judicial review of any previous decision or order, the railroad commission may accept a supersedeas bond. Each supersedeas bond shall be for the amount of the penalty and in a form approved by the railroad commission and shall stay the collection of the penalty until all judicial review of the decision or order is final.

(k) If through judicial review of the decision or order it is determined that no violation occurred or that the amount of the penalty should be reduced or not assessed, the railroad commission shall, within the 30 day period immediately following the determination, if the penalty has been paid to the railroad commission, remit the appropriate amount to the public utility, with accrued interest, or where a supersedeas bond has been posted, the railroad commission shall execute a release of such bond.

(l) Failure to forward the money to the commission within the time provided by Section (j) of this article results in a waiver of all legal rights to contest the violation or the amount of the penalty.

(m) Civil penalties owed under this article may be recovered in a civil action brought by the attorney general at the request of the commission.

(n) Judicial review of the order or decision of the railroad commission assessing the penalty shall be under the substantial evidence rule and shall be instituted by filing a petition with the district court of Travis County, Texas, and not elsewhere, as provided for in Section 19, Administrative Procedure and Texas Register Act (Article 6252 13a, Vernon's Texas Civil Statutes).

Art. 6063. **RECEIVER.**

Whenever any person, firm or corporation, owning, operating or controlling such gas pipe line shall violate any provision hereof or any rule or regulation of the Commission, the Commission shall, whenever in its judgment the public interests require it, apply to any court of this State having jurisdiction for a receivership of such concern guilty of such violation. Such receiver shall control and manage the property of such gas pipe line under the direction of the court as provided by law in receivership matters. The grounds for appointment of receiver provided for in this article shall be in addition to other grounds provided by law.

Art. 6064. **DUTIES OF PIPE LINE EXPERT.**

The supervisor shall likewise assist the Commission in the performance of its duties under this subdivision under the direction of the Commission, under such rules and regulations as it may prescribe.

Art. 6065. **EMPLOYEES OF COMMISSION.**

The Commission may employ and appoint, from time to time, such experts, assistants, accountants, engineers, clerks and other persons as it deems necessary to enable it at all times to inspect and audit all records or receipts, disbursements, vouchers, prices, pay rolls, time cards, books and official records, to inspect all property and records of the utilities subject to the provisions hereof, and to perform such other services as may be directed by the Commission or under its authority. Such persons and employees of the Commission shall be paid for the service rendered such sums as the Commission may fix.

Art. 6066. **EXPENDITURES.**

The salary and expenses of the expert and his assistant and the salaries, wages, fees, and expenses of every other person employed or appointed by the Commission under the provisions of this subdivision, and all other expenses, costs, and charges, including witness fees and mileage incurred by/or under authority of the Commission or a Commissioner in administering and enforcing the provisions of this subdivision or in exercising any power or authority hereunder, shall be paid out of the General Revenue Fund by the State Treasurer on warrants of the Comptroller on orders or vouchers approved by the Commission or Chairman thereof. The entire amount derived from the tax imposed by Article 6060, as amended, shall be deposited to the General Revenue Fund.

Art. 6066f. **NATURAL GAS SUPPLIES FOR AGRICULTURAL PURPOSES.**

Except to the extent that natural gas supplies are required to maintain natural gas service to residential users or hospitals and similar uses vital to public health and safety, no person, firm, corporation, partnership, association, or cooperative which sells natural gas for irrigation and also sells and distributes natural gas within the limits of any municipality or delivers gas to the boundary of any municipality for resale in the municipality shall curtail the supply of natural gas for agricultural purposes, including but not limited to irrigation pumping and crop drying.

OTHER PERTINENT LAWS

Texas Rev. Civ. Stat. Ann. Arts. 1440, 1440a

Art. 1440. DEPOSIT FOR INSTALLING SERVICE.

Every person, firm, company, corporation, receiver or trustee engaged in the furnishing of water, light, gas or telephone service which requires the payment on the part of the user of such service a deposit of money as a condition precedent to furnishing the same, shall pay six percent (6%) interest per annum on such deposit to the one making same, or to his heirs or assigns, from the time of such deposit, the same to be paid annually on demand or sooner if such service be discontinued, When such service is discontinued, such deposit, together with any unpaid interest thereon, or such part of such deposit and unpaid interest, not consumed in bills due for such service, shall be returned to such depositor, his heirs or legal representatives.

As amended Acts 1963, 58th Leg., p. 50, Ch. 32, Sec. 1.

Art. 1440a. DEPOSIT FOR INSTALLING SERVICE.

Every person, firm, company, corporation, receiver or trustee engaged in the furnishing of water, light, gas or telephone service which requires the payment on the part of the user of such service a deposit of a money as a condition precedent to furnishing any such service, shall pay six percent (6%) interest per annum on such deposit to the one making same, or to his heirs or assigns, from the time of such deposit, the same to be paid annually on demand, or sooner if such service be discontinued. When such service is discontinued, such deposit, together with any unpaid interest thereon, or such part of such deposit and unpaid interest not consumed in bills due for such service, shall be returned to such depositor, his heirs or legal representatives. Whoever violates any provision of this article shall be fined not less than twenty-five dollars ($25) nor more than two hundred dollars ($200), or be confined in jail not less than six (6) months nor more than one year, or both.

2 Nat. Res. Code §91.051 - §91.062

§91.051. Title

This chapter may be cited as the Standard Gas Measurement Law.

§91.052. Definition

(a) The term "cubic foot of gas" or "standard cubic foot of gas" means the volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base.

(b) The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit. If the conditions of pressure and temperature differ from this standard, conversion of the volume from these conditions to the standard conditions shall be made in accordance with the ideal gas laws, corrected for deviation.

§91.053. Commission Determination

The commission shall determine the average temperature of gas as produced in each oil and gas field in Texas, other variable factors necessary to calculate the metered volumes in

accordance with the ideal gas laws, and the variable factors to correct for deviation from the ideal gas laws in each of the oil and gas fields in the state.

§91.054. **Notice and Hearing**

On request of any interested person, the comission shall give proper notice and hold a public hearing before making a determination under Section 91.053 of this code.

§91.055. **Findings and Rules**

On making the determination, the commission promptly shall make its findings and shall adopt the reasonable field rules that may be necessary to effectuate the provisions of this subchapter.

§91.056. **Use of Findings and Field Rules**

(a) Any person may use the findings and field rules of the commission for any purposes under this subchapter.

(b) If the findings or field rules are not used as provided in Subsection (a) of this section in determining volumes under this subchapter, the volumes otherwise determined shall be corrected to the basis of the standard cubic foot of gas as defined in Section 91.052 of this code.

§91.057. **Method of Reporting**

A person required to report volumes of gas under the laws of this state shall report the volumes in number of standard cubic feet calculated and determined under the provisions of this subchapter.

§91.058. **Sale, Purchase, Delivery, and Receipt of Gas**

(a) Each sale, purchase, delivery, and receipt of gas by volume in this state by, for, or on behalf of an oil and gas lease owner, royalty owner under a lease, or other mineral interest owner shall be made and the gas shall be measured, calculated, purchased, delivered, and accounted for on the basis of a standard cubic foot of gas as defined in this subchapter and determined under this subchapter.

(b) If the provisions of this subchapter operate to change the basis of measurement provided in existing contracts, the price for gas, including royalty gas, provided for in the contracts shall be adjusted to compensate for the change in method of measuring the volume of gas delivered under the contracts if either the purchaser or seller so desires.

(c) This section is intended to protect parties to contracts in existence on October 4, 1949, so that the total amount of money paid for a volume of gas purchased or required to be accounted for under these contracts shall remain unaffected by this subchapter.

§91.059. **Constitutionality**

If the provisions of Section 91.058 of this code or any part of that section are held to be invalid or unconstitutional by the courts, the remaining portions of this subchapter shall become ineffective and inoperative.

§91.060. **Penalty**

(a) Any person who, as purchaser, shall knowingly fail or refuse to measure, calculate, or account in the manner required in this subchapter for any gas purchased is subject to a penalty of not less than $10 nor more than $500 for each offense.

(b) The penalty is recoverable in the name of the state in a district court in Travis County.

(c) Each day a violation is committed constitutes a separate offense.

(d) It is a defense to a claim for the penalty that the commission has not made the findings under Section 91.055 of this code with regard to the particular field in question.

§91.061. Civil Suit

None of these provisions shall prevent an aggrieved person from maintaining a civil suit for damages in the county or counties in which the gas is produced.

§91.062. Applicability of Certain Provisions

None of the provisions of Section 91.058 through 91.061 of this code affect or apply to purchases or sales made on any basis other than a volume basis.

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