
Gas Transmission PipelinesENGINEERING PROCEDURE

1 SCOPE AND INTENT**1.1 SCOPE**

1.1.1 This ENGINEERING SERVICES, LP Engineering Specification covers the design, fabrication, installation, inspection, testing, and safety aspects for operation and maintenance of gas transmission systems, including gas pipelines and gas compressor stations. This specification also covers the components of piping systems including, but not limited to, pipe, valves, fittings, flanges, bolting, and gaskets.

1.1.2 This specification does not apply to:

- (a) Design and manufacture of pressure vessels covered by ASME BPV Code;
- (b) Piping with metal temperatures above 450⁰F or below -20⁰F;
- (c) The design and manufacture of proprietary items of equipment, apparatus, or instruments;
- (d) Liquid petroleum transportation piping systems (refer to ANSI/ASME B31.4);

Approved: _____ **Date:** _____
Manager Safety, Health, and Environmental

Approved: _____ **Date:** _____
Environmental Manager

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- 1.2 INTENT** - The intent of this specification is to provide engineering guidance for safe construction, operation, maintenance, and inspection of gas transmission piping systems. Due to the complex nature of governing national codes, these specifications can not be written with sufficient detail to cover all possibilities concerning safety with gas transportation systems. Responsible design, construction, operation, and maintenance personnel must have the experience and training to adequately cover all work related problems. All work performed within the scope of this specification shall meet or exceed the requirements in ANSI/ASME B31.8, "Gas Transmission and Distribution Piping Systems" and 49CFR-Part 192, "Transportation of Natural and Other Gas By Pipeline; Minimum Federal Safety Standards".

2 REFERENCES**2.1 ASTM**

- A53 Pipe, Steel, Black and Hot Dipped, Zinc Coated, Welded and Seamless
- A105 Forgings, Carbon Steel, for Piping Components
- A106 Seamless Carbon Steel Pipe for High-Temperature Service
- A194 Carbon and Alloy Steel Nuts for Bolts for High-Pressure and High-Temperature Service
- A307 Carbon Steel Externally Threaded Standard Fasteners

2.2 API

- 5L Line Pipe
- 6D Pipeline Valves
- 510 Pressure Vessel Inspection
- 570 Piping Inspection
- 1104 Standard for Welding Pipelines and Related Facilities
- 1107 Recommended Pipeline Maintenance Welding Practices
- RP 5L1 Recommended Practice for Railroad Transportation of Line Pipe
- RP 5L5 Recommended Practice for Marine Transportation of Line Pipe
- RP 5L6 Recommended Practice for Transportation of Line Pipe on Inland Waterways

- 2.3 NFPA 70** National Electrical Code

2.4 MSS

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- SP-6 Standard Finishes for Contact Faces of Pipe Flanges and Connecting End Flanges of Valves and Fittings
- SP-25 Standard Marking System for Valves, Fittings, Flanges, and Unions.
- SP-44 Steel Pipe Line Flanges

2.5 AWS A3.0 Welding Terms and Definitions

- 2.6 NACE**
 - RP-01-69 Control of External Corrosion on Underground or Submerged Metallic Piping Systems
 - RP-01-75 Control of Internal Corrosion in Steel Pipelines and Piping Systems
 - RP-01-77 Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems Corrosion Data Survey

2.7 ASME

- B1.1 Unified Inch Screw Threads
- B1.20.1 Pipe Threads (Except Dryseal)
- B16.5 Steel Pipe Flanges and Flanged Fittings
- B16.9 Factory-Made Wrought Steel Buttwelding Fittings
- B16.11 Forged Steel Fittings, Socket-Welding and Threaded
- B16.20 Ring-Joint Gaskets and Grooves for Steel Pipe Flanges
- B16.34 Steel Valves (Flanged and Buttwelding End)
- B31G Manual for Determining the Remaining Strength of Corroded Pipelines
- B31.3 Chemical Plant and Petroleum Refinery Piping
- B31.4 Liquid Petroleum Transportation Piping Systems
- B31.8 Gas Transportation and Distribution Piping Systems
- BPV (Boiler and Pressure Vessel) Code
 - Section VIII, Pressure Vessels
 - Section IX, Welding
 - Section V, Nondestructive Examination
- SI-1 ASME Orientation and Guide for Use of SI (Metric) Units

3 PIPING SYSTEMS DEFINITIONS

3.1 GENERAL TERMS

- 3.1.1 Gas:** any gas or mixture of gases suitable for domestic or industrial fuel and transmitted through a piping system.
- 3.1.2 Operating Company:** the individual, partnership, corporation, public agency, or other entity that operates the gas transmission facilities.
- 3.1.3 Private rights-of-way:** rights-of-way not located on roads, streets, or highways used by the public, or on railroad rights-of-way.
- 3.1.4 Parallel encroachment:** Portion of a pipeline route which lies within, runs in a generally parallel direction, and does not necessarily cross, the rights-of-way of a road, street, highway, or railroad.
- 3.1.5 Hot taps:** branch piping connections to a pipeline made while the pipeline is under gas pressure.
- 3.1.6 Vault:** underground structure which contains piping and related components which allows personnel entry.

3.2 PIPING SYSTEMS

- 3.2.1 Pipeline or transmission line:** pipe installed for the purpose of transmitting gas from one process to another.
- 3.2.2 Miscellaneous systems**
- 3.2.2.1 Instrument piping:** all piping, valves, and fittings used to connect instruments to main piping, to other instruments and apparatus, or to measuring equipment.
- 3.2.2.2 Control piping:** all piping, valves, and fittings used to interconnect air, gas, or hydraulically operated control apparatus or instrument transmitters and receivers.
- 3.2.2.3 Sample piping:** all piping valves, and fittings used for the collection of samples of gas, steam, water, or oil.

3.3 PRESSURE RELIEF STATIONS AND REGULATORS

- 3.3.1 Pressure regulating station:** equipment installed for the purpose of automatically reducing and regulating pressure in the section downstream of the station. Included are piping and auxiliary devices such as valves, control instruments, control lines, the enclosure, and ventilation equipment.
- 3.3.2 Pressure limiting station:** equipment which will control gas flow to prevent gas pressure from exceeding a predetermined value.
- 3.3.3 Pressure relief station:** equipment which will vent gas to prevent gas pressure from exceeding a predetermined value.

3.4 VALVES

- 3.4.1 Stop valve:** valve installed to stop the flow of gas in a pipe.
- 3.4.2 Check valve:** valve designed to permit flow in one direction and to close automatically to prevent flow in the reverse direction.

3.5 PIPE AND PIPING TERMS

- 3.5.1 Pipe:** a tubular product. Cylinders formed from plate in the course of fabrication of auxiliary equipment are not pipe for the purposes of this standard.
- 3.5.2 Cold expanded pipe:** seamless or welded pipe which is formed and then expanded in the pipe mill while cold to permanently increase the circumference by at least 0.50%.

3.6 DIMENSIONAL TERMS

- 3.6.1 Length:** a piece of pipe as delivered from the mill; sometimes referred to as a "joint".
- 3.6.2 Nominal wall thickness, t :** wall thickness computed by or used in the B31.8 design equation.
- 3.6.3 NPS (nominal pipe size):** a dimensionless designator of pipe which indicates a standard pipe size when followed by an appropriate number (e.g., NPS 12).

3.7 MECHANICAL PROPERTIES

- 3.7.1 Yield strength:** the strength at which a material exhibits a specified limiting permanent set or produces a specified total elongation under load.
- 3.7.2 Tensile strength:** the highest unit tensile stress over the original cross section that a material can sustain before failure.
- 3.7.3 Specified minimum yield strength (SMYS):** minimum yield strength as prescribed by the specification for a given purchase.
- 3.7.4 Specified minimum tensile strength:** minimum tensile strength as required by the specification when purchasing pipe.
- 3.7.5 Specified minimum elongation:** minimum elongation (expressed in percent of the gage length) for a tensile test specimen.

3.8 STEEL PIPE

- 3.8.1 Carbon Steel:** steel is considered to be *carbon steel* when no minimum content is specified or required for aluminum, boron, chromium, molybdenum, nickel, titanium, tungsten, vanadium, zirconium, or any other element added to achieve a desired alloying effect; when the specified minimum for copper does not exceed 0.40%, or when the maximum content specified for any of the following elements does not exceed the percentages noted:

manganese	1.65%
silicon	0.60%
copper	0.60%

- 3.8.2 Alloy Steel:** steel is considered to be *alloy steel* when the maximum concentration for various components exceeds the requirements in ANSI B31.8, paragraph 804.242.

- 3.8.3 Pipe Manufacturing Processes:** The following types of welded joints are acceptable for pipe manufactured to this specification:

(a) Electric-resistance-welded pipe

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- (b) Furnace butt-welded pipe
- (c) Spiral welded pipe
- (d) Double submerged-arc-welded pipe
- (e) Seamless pipe

4 DESIGN, FABRICATION, OPERATION, AND TESTING TERMS

4.1 GENERAL

4.1.1 Location class: a geographic area along a pipeline classified according to the number and proximity of buildings intended for human occupancy.

4.1.2 Upgrading: the qualifying of an existing pipeline for a higher maximum allowable operating pressure.

4.2 DESIGN

4.2.1 Pressure Terms

4.2.1.1 Pressure: pounds per square inch above atmospheric pressure, abbreviated as psig.

4.2.1.2 Design Pressure: maximum pressure permitted by ANSI B31.8.

4.2.1.3 Maximum operating pressure: highest pressure at which a piping system is operated during a normal operating cycle.

4.2.1.4 Maximum allowable operating pressure (MAOP): maximum pressure at which a gas system may be operated in accordance with the provisions of ANSI B31.8.

4.2.1.5 Maximum allowable test pressure: maximum internal fluid pressure permitted by the Code for a pressure test based upon the material and location involved.

4.2.1.6 Overpressure protection: device or equipment installed for the purpose of preventing the pressure in a pressure vessel or pipeline from exceeding a predetermined value.

4.2.1.7 Standup pressure test: a leak test.

4.2.2 Temperature Terms

4.2.2.1 Temperatures (expressed in degrees Fahrenheit, °F, unless specifically stated otherwise).

4.2.2.2 Ambient temperature: the temperature of the surrounding medium.

4.2.2.3 Ground temperature: the temperature of the earth at pipe depth.

4.2.3 Stress Terms

4.2.3.1 Stress: the resultant internal force that resists change in the size or shape of a body acted upon by external forces. In the Pipeline Code, stress is often used as being synonymous with unit stress which is the stress per unit area (psi).

4.2.3.2 Operating stress: the stress in a pipe under normal operating conditions.

4.2.3.3 Hoop stress, S_H : the stress in a pipe of wall thickness, t , acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe and is determined by Barlow's formula:

$$S_H = PD/2t$$

4.2.3.4 Maximum allowable hoop stress: the maximum hoop stress permitted by the Pipeline Code for the design of a piping system.

4.2.3.5 Secondary stress: stress created in the pipe wall by loads other than the internal fluid pressure, e.g., backfill loads, traffic loads, loads caused by natural hazards, beam action in a span, loads at supports, and at connections to the pipe.

5 MATERIALS AND EQUIPMENT

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5.1 QUALIFICATION OF MATERIALS AND EQUIPMENT - Line pipe for use on ENGINEERING SERVICES, LP gas transmission pipelines will be manufactured to the requirements in API 5L, "Line Pipe".

5.2 MARKING: All valves, fittings, flanges, bolting, pipe, and tubing shall be marked in accordance with the marking section of the standards and specifications to which the items were manufactured or in accordance with the requirements of MSS SP-25.

5.3 MATERIAL SPECIFICATIONS

5.3.1 Steel Pipe

5.3.1.1 Only steel pipe shall be installed on Company gas transmission pipelines and shall be manufactured to the appropriate specifications in API 5L, "Specifications for Line Pipe". Seamless, double submerged arc, or electric resistance welded line pipe shall be specified on the purchase order.

5.3.1.2 For pipe having a specified minimum yield strength of 56,000 psi or greater, fracture toughness tests should be required.

5.3.1.3 For mechanical strength, minimum pipe wall thickness for different schedule pipe is as follows:

NPS 2 and smaller	Schedule 80
NPS 4	Schedule 40
NPS 6 and larger	0.250"

5.4 EQUIPMENT SPECIFICATIONS

5.4.1 Fittings

5.4.1.1 General: All fittings NPS 2 and larger shall be butt welding fittings in accordance with ANSI B16.9. Weld fittings should have physical

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properties equivalent to the pipe to which the fittings will be welded. Heavier wall, lower strength fittings may be used with lighter wall, higher strength pipe with transitions at the ends of the fittings in accordance with the requirements of ANSI B31.8.

5.4.1.2 Elbows: Long radius (1.5D) elbows are recommended for fabricated assemblies. 5D ells are required where running of conventional and/or instrumented pigs is required.

5.4.1.3 Small Fittings: Fittings NPS 1-1/2" or smaller should be threaded and shall be seal welded. Fittings should be forged steel and manufactured in accordance with B16.11.

5.4.1.4 Flanges: Flange types, facings, gaskets, and bolting shall be purchased and installed in accordance with the requirements in this specification.

5.4.1.5 Valves: Pipeline valves must be manufactured to the requirements in API 6D, "Pipeline Valves".

5.5 TRANSPORTATION OF LINE PIPE

If line pipe is transported by railroad to be installed in a service where the operating pressure is 20% or more of SMYS, the outer diameter to wall thickness ratio must be 70:1 or less.

5.6 CONDITIONS FOR THE REUSE OF PIPE

5.6.1 Reuse of Steel Pipe

5.6.1.1 Requirements for the reuse of steel line pipe is summarized in paragraph 817, ANSI B31.8 with subparagraph 817.13 showing the necessary qualifications for pipe for use at stress levels above 6000 psi or for service involving close coiling or bending. Qualification tests include:

- (a) Inspection
- (b) Bending and coiling properties for pipe NPS 2 and smaller
- (c) Determination of wall thickness
- (d) Longitudinal joint factor

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- (e) Weldability
- (f) Surface defects
- (g) Determination of yield strength
- (h) S value
- (i) Hydrostatic test

5.6.1.2 Company Engineering Department should be contacted for assistance when the reuse of steel pipe is considered. A cost-effective test program will be developed for each case.

6 WELDING

6.1 GENERAL

6.1.1 Welding Terms

Definitions pertaining to welding as used in ANSI 31.8 and 49CFR192 have been established by the American Welding Society and are listed in ANSI/AWS A3.0.

6.2 PREPARATION FOR WELDING

6.2.1 Butt Welds - ANSI B31.8, Appendix I, Figure I4 and I5 show examples of acceptable combinations for pipe end preparations.

6.2.2 Fillet Welds - ANSI B31.8, Appendix I, Figure I6, "Recommended Attachment Details of Flanges", Figure I1 and Figure I2 show minimum dimensions for fillet welds used in the attachment of slip-on flanges and socket-welded joints.

6.2.3 Seal Welds - Seal welding shall be performed by qualified welders. Seal welding is required for all threaded connections in gas service. Seal welds do not contribute to the strength of the joint.

6.3 QUALIFICATION OF PROCEDURES AND WELDERS

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6.3.1 Requirements for Qualification of Procedures and Welders on Piping Systems to Operating at Hoop Stresses of Less Than 20% of the Specified Minimum Yield Strength.

Welders whose work is limited to piping operations at hoop stress levels of less than 20% of SMYS shall be qualified under ASME BPV Code, Section IX or API 1104. Qualification by Appendix G, ANSI B31.8 is not permitted for welders on Company pipeline project or maintenance work.

6.3.2 Requirements for Qualification of Procedures and Welders on Piping Systems to Operate at Hoop Stresses of 20% or More of the Specified Minimum Yield Strength

6.3.2.1 Welding procedures and welders performing under this classification shall be qualified under ASME BPV Code, Section IX or API Standard 1104.

6.3.2.2 Welder qualification under API 1104 for work on compressor station piping must be based on the destructive mechanical test requirements in API 1104.

6.3.3 Variables Requiring Separate Qualification of Welding Procedures and Welders

ANSI B31.8, paragraph 823.23 allows materials under grouping P-No. 1 with a carbon content not exceeding 0.32% and a carbon equivalent ($C + 1/4 Mn$) not exceeding 0.65% by ladle analysis. This allowance is an exception to the references in the BPV Code and API 1104.

6.3.4 Welder Requalification Requirements

Welder requalification tests are required in the following instances:

- (a) All welders must be requalified at least once per year.
- (b) Welder has not worked in a given process of welding for a period of six (6) months or more.
- (c) There is some reason to question a welder's ability.

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6.3.5 Qualification Records

6.3.5.1 Welding Procedure Specifications (WPS) and Procedure Qualification Records (PQR) shall be maintained as long as the procedure is in use.

6.3.5.2 During a given construction project, Company and/or contractor will maintain a record of the welders qualified showing the dates and results of the test.

6.3.5.3 All contractors are required to have their Company's WPS and PQR for work in a particular welding operation. Welders that complete the welding operation for the procedure qualification are considered qualified for that procedure. All other welders must be tested.

6.4 PREHEATING

6.4.1 Carbon steels having a carbon content in excess of 0.32% or a carbon equivalent of 0.65% or higher shall be preheated to the temperature in the welding procedure.

6.4.2 Preheat can be applied by any suitable technique provided the application is uniform and the temperature does not fall below the minimum during welding.

6.4.3 Preheat temperature shall be checked by temperature-indicating crayons, thermocouple pyrometers, or any other recognized method.

6.5 STRESS RELIEVING

6.5.1 Maximum carbon or carbon equivalent - See preheating requirements. ASME Section VIII shows stress relief requirements.

6.5.2 Thickness - Required for all welds when thickness exceeds 1-1/4 in.

6.5.3 Different thickness for parts to be welded - Thicker part governs preheat requirements. Thickness of the pipe or header governs preheat requirements for branch connections, slip-on flanges, or socket weld fittings.

6.5.4 Stress Relieving Temperature

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1100⁰F or more for carbon steels. Exact temperature range and stress relieving procedure shall be included on the WPS.

6.5.5 Methods of Stress Relieving

- (a) Heat the complete structure.
- (b) Heat welded area prior to attachment to a larger section.
- (c) For pipeline work, uniformly heat a band of the pipe with the weld at the center and temperature maintained at the required level to a distance of 2-inches on each side of the weld reinforcement.
- (d) For branch connections, locally heat to a distance of 2-inches from the attachment weld and maintain temperatures.

6.5.6 Equipment for Local Stress Relieving

6.5.6.1 Stress relieving may be accomplished by electric induction, electric resistance, fuel-fired ring burners, fuel-fired torch, or other suitable means of heating, provided that a uniform temperature is obtained and maintained.

6.5.6.2 Stress relieving temperature shall be checked by thermocouple pyrometers or other suitable equipment.

6.6 WELDING AND INSPECTION TESTS

6.6.1 Inspection of Welds on Piping Systems Intended to Operate at Less Than 20% of the Specified Minimum Yield Strength.

ANSI B31.8, paragraph 826.1 allows the quality of these welds to be checked visually on a sampling basis. Defective welds shall be repaired or removed from the line. This procedure shall be coordinated with Engineering or Operations Planning to insure that the pipeline will not be used for higher pressure service during its lifetime.

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6.6.2 Inspection and Tests for Quality Control of Welds on Piping Systems Intended to Operate at 20% or More of the Specified Minimum Yield Strength

6.6.2.1 Weld quality shall be determined by visual examination (VT) and radiographic examination (RT), angle-beam ultrasonic examination (UT), magnetic particle testing (MT), visual examination (VT), or liquid penetrant inspection (PT). Inspectors shall be qualified to the requirements in ASNT TC-1A to a minimum Level II certification.

6.6.2.2 40% of weld production will be selected by the Company representative for random nondestructive examination. Each weld selected for testing shall be examined over the entire circumference of the joint.

6.6.2.3 Acceptability standards are given in API 1104. Each weld must meet these standards at a minimum or must be removed and/or repaired.

Radiographic procedures shall meet at a minimum the requirements in API 1104. ENGINEERING SERVICES, LP reserves the right to make repairs to ASME Standard B31.3 on DOT regulated pipelines. In each case, the particular circumstances of the project will determine which standard shall be used on DOT regulated Pipelines. For work to be performed inside ENGINEERING SERVICES, LP or Conoco Battery limits, the more stringent Standard of ASME B31.3 shall be used.

6.7 REPAIR OR REMOVAL OF DEFECTIVE WELDS IN PIPING INTENDED TO OPERATE AT 20% OR MORE OF THE SPECIFIED MINIMUM YIELD STRENGTH

6.7.1 Defective welds shall be repaired or removed.

Repairs shall be in accordance with API 1104. ENGINEERING SERVICES, LP reserves the right to make repairs to ASME Standard B31.3 on DOT regulated pipelines. In each case, the particular circumstances of the project will determine which standard shall be used on DOT regulated Pipelines. For work to be performed inside ENGINEERING SERVICES, LP or Conoco Battery limits, the more stringent Standard of ASME B31.3 shall be used.

7 PIPING SYSTEM COMPONENTS AND FABRICATION DETAILS

7.1 GENERAL

7.1.1 The purpose of this section is to provide a set of standards for piping systems covering:

- (a) Specifications and selection for all items and accessories entering into the piping system, excluding the pipe.
- (b) Acceptable methods of making branch connections.
- (c) Provisions for the effects of temperature changes.
- (d) Approved methods for support and anchorage of piping systems, both exposed and buried.

7.1.1.1 This section does not include:

- (a) Pipe materials (See Section 5)
- (b) Welding procedures (See Section 6)
- (c) Design of pipe (See Section 8)
- (d) Installation and testing of piping systems (See Section 8)

7.2 PIPING SYSTEM COMPONENTS

7.2.1 All components of piping systems including valves, flanges, fittings, headers, special assemblies, etc., shall be designed in accordance with the applicable requirements of ANSI/ASME B31.8 and recognized engineering practices to withstand operating pressures and other specified loadings. Components shall be selected that are designed to withstand the specified field test pressure without failure, leakage, or impairment of serviceability.

7.2.2 Valves and Pressure Reducing Devices

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7.2.2.1 Valves shall conform to standards and specifications in this section and ANSI/ASME B31.8 and shall be used only in accordance with the service recommendations of the manufacturer.

(a) Valves manufactured in accordance with the following standards may be used in LCCC gas transmission pipeline systems:

1. ANSI B16.34 Steel Valves
2. API 6D Pipeline Valves

(b) Valves having shell (body, bonnet, cover, and/or end flange) components made of cast ductile iron in compliance with ASTM A395 and having dimensions conforming to ANSI B16.34 and API 6D may be used at pressures not exceeding 80% of the pressure ratings for comparable steel valves at their listed temperature provided operating pressure is less than 1000 psi and no welding has been performed in the valve fabrication.

(c) Valves having shell components made of cast iron shall not be used in gas piping components for compressor stations.

7.2.2.2 Threaded valves shall be threaded according to API 5L or ANSI B1.20.1.

7.2.2.3 Pressure reducing devices shall conform to the requirements for valves in comparable service conditions.

7.2.3 Flanges

7.2.3.1 Flange Types and Facings

7.2.3.1.1 The dimensions and drilling for all line or end flanges shall conform to one of the following standards:

- (a) ANSI B16 Series listed in Appendix A (for iron and steel)
- (b) MSS SP-44 Steel Pipe Line Flanges
- (c) Appendix Light-Weight Steel Flanges

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(d) ANSI B16.24 Brass or Bronze Flanges and Flanged Fittings

7.2.3.1.2 The following classes of flanges are permitted with certain restrictions (See Paragraph 831.21, Flange Types and Fittings, ANSI B31.8:

1. Integrally cast or forged flanges for pipe, fittings, or valves
2. Threaded companion flanges
3. Lapped flanges
4. Slip-on flanges
5. Welding neck flanges

7.2.3.1.3 Cast iron, ductile iron, and steel flanges shall have contact faces finished in accordance with MSS SP-6.

7.2.3.1.4 Nonferrous flanges shall have contact faces finished to ANSI B16.34.

7.2.3.1.5 Class 25 and 125 cast iron integral or threaded companion flanges may be used with a full-face gasket or with a flat ring gasket extending to the inner edge of the bolt holes. When using a full-face gasket, the bolting may be of alloy steel (ASTM A193). When using a ring gasket, the bolting shall be of carbon steel, equivalent to ASTM A307 Grade B, without heat treatment other than stress relief.

7.2.3.1.6 When bolting together two Class 250 integral or threaded companion cast iron flanges having 1/16 in. raised faces, the bolting shall be carbon steel equivalent to ASTM A307 Grade B without heat treatment other than stress relief.

7.2.3.1.7 Class 150 steel flanges may be bolted to Class 125 cast iron flanges. When such construction is used, the 1/16 in. raised face on the steel flange shall be removed. When bolting such flanges together using a flat ring gasket extending to the inner edge of the bolt holes, the bolting shall be carbon steel equivalent to ASTM A307 Grade B without heat treatment other than stress relief. When bolting such flanges together

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using a full-face gasket, the bolting may be alloy steel (ASTM A193).

7.2.3.1.8 Class 300 steel flanges may be bolted to Class 250 cast iron flanges. Where such construction is used, the bolting shall be carbon steel equivalent to ASTM A307 Grade B without heat treatment other than stress relief.

7.2.3.1.9 Forged steel welding neck flanges having an outside diameter and drilling the same as ANSI B16.1, but with modified flange thicknesses, hub dimensions, and special facing details, may be used to bolt against flat faced cast iron flanges and may operate at the pressure-temperature ratings given in ANSI B16.1 for Class 125 cast iron piping flanges, provided:

- (1) The minimum flange thickness T is not less than that specified for light-weight flanges;
- (2) Flanges are used with nonmetallic full-face gaskets extending to the periphery of the flange;
- (3) The joint design has been proven by test to be suitable for the ratings.

7.2.3.1.10 Ductile iron flanges shall conform to the requirements of ANSI B16.42. Bolting requirements for ductile iron flange joints shall be the same as carbon and low alloy steel flanges.

7.2.3.2 Bolting

7.2.3.2.1 For all flange joints, studbolts shall be used and each end shall extend completely through the nut on each end.

7.2.3.2.2 For all flange joints other than cast iron, the bolting shall be alloy steel conforming to ASTM A193, A320, or A354, or heat treated carbon steel conforming to ASTM 449.

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7.2.3.2.3 Alloy-steel bolting conforming to ASTM A193 or A354 shall be used for insulating flanges if such bolting is made 1/8 in. undersized. This requirement is important for cathodic protection installation after construction.

7.2.3.2.4 Materials used for nuts shall conform to ASTM A194 and A307. A307 nuts shall be used only with A307 bolting.

7.2.3.2.5 All carbon and alloy-steel bolts, studbolts, and their nuts shall be threaded in accordance with the following thread series and dimension classes as required by ANSI B1.1:

- (1) All carbon-steel bolts and studbolts shall have coarse threads, Class 2A dimensions, and their nuts with Class 2B dimensions.
- (2) All alloy-steel bolts and studbolts of 1 in. and smaller diameter shall be of the coarse-thread series: nominal diameters 1-1/8 in. and larger shall be 8-thread series. Bolts and studbolts shall have 2A dimensions; nuts shall have 2B dimensions.

7.2.3.2.6 Bolts shall have American Standard regular square heads or heavy hexagonal heads and shall have American National Standard heavy hexagonal nuts conforming to the dimensions of ANSI B18.2.1 and B18.2.2.

7.2.3.3 Gaskets

7.2.3.3.1 Materials for gaskets shall be capable of withstanding the maximum pressure and maintaining its physical and chemical properties at any service temperature.

7.2.3.3.2 Gaskets used under pressure and at temperatures above 250°F shall be of noncombustible material. Metallic gaskets shall not be used with Class 150 standard or lighter flanges.

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7.2.3.3.3 Asbestos composition gaskets may be used as permitted in ANSI B16.5.

7.2.3.3.4 The use of metal or metal-jacketed asbestos gaskets (either plain or corrugated) is not limited as to pressure, provided that the gasket material is suitable for the service temperature. These types of gaskets are recommended for use with the small male and female or the small tongue and groove facings. They may also be used with steel flanges with lapped, large male and female, large tongue and groove, or raised face flanges.

7.2.3.3.5 In order to secure higher unit compression on the gasket, metallic gaskets of a width less than the full male face of the flange may be used with raised face, lapped, or large male and female facings. The width of the gasket for small male and female or for tongue and groove joints shall be equal to the width of the male face or tongue.

7.2.3.3.6 Rings for ring joints shall be of dimensions established in ANSI B16.20. The material for these rings shall be suitable for the service conditions encountered and shall be softer than the flanges.

7.2.3.3.7 The insulating material shall be suitable for the temperature, moisture, and other environmental conditions where it will be used.

7.2.4 Fittings Other than Valves and Flanges

7.2.4.1 Standard Fittings

7.2.4.1.1 The minimum metal thickness of flanged or threaded fittings shall not be less than specified for the pressures and temperatures in the applicable American National Standards or the MSS Standard Practice.

7.2.4.1.2 Steel butt welding fittings shall comply with either ANSI B16.9 or MSS SP-75 and shall have pressure/temperature ratings

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based on stresses for pipe of the same or equivalent material. The actual bursting strength of fittings shall equal the computed bursting strength of pipe of designated material and wall thickness. Mill hydrotesting is not required for steel butt welding fittings, but the fittings must be capable of withstanding a field pressure test to the manufacturer's test pressure.

7.2.4.1.3 Steel socket-welding fittings shall comply with ANSI B16.11.

7.2.4.1.4 Ductile iron flanged fittings shall comply with the requirements of ANSI B16.42 or ANSI A21.14.

7.2.4.2 Branch Connections

7.2.4.2.1 Welded branch connections on steel pipe must meet the design requirements of paragraphs 7.2.5 and 7.2.6.

7.2.4.2.2 Mechanical fittings may be used for making hot taps on pipelines provided the fittings are designed for the operating pressure of the pipeline.

7.2.4.3 Special Components Fabricated by Welding

7.2.4.3.1 This paragraph covers piping system components other than assemblies consisting of pipe and fittings joined by circumferential welds.

7.2.4.3.2 All welding shall be performed using procedures and welders that are qualified to the Welding Section.

7.2.4.3.3 Branch connections shall meet the design requirements in ANSI B31.8, paragraphs 831.4, 831.5, and 831.6.

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7.2.4.3.4 Prefabricated units, other than regularly manufactured butt welding fittings, which use plate and longitudinal seams shall be designed, constructed, and tested under requirements of the ASME BPV Code.

7.2.4.3.5 Every prefabricated unit produced under this part shall be hydrotested to a pressure equal to the test pressure for the system in which the unit will be installed. For installation in existing facilities, the fabricated unit shall withstand a leak test at the operating pressure of the line.

7.2.4.4 Pressure Design of Other Pressure Containing Components

Pressure-containing prefabricated assemblies are approved for use in the absence of fabrication standards if the assembly has successfully operated as an identical assembly in equivalent service. In the absence of service experience, the design pressure shall be established by the requirements in B31.8 and at least one of the following tests:

- (a) Proof tests (as described in paragraph UG-101, Section VIII, Division I, ASME BPV Code.
- (b) Experimental stress analysis (described in Appendix 6, Section VIII, Division 2, ASME BPV Code.
- (c) Engineering calculations.

7.2.4.5 Closures

7.2.4.5.1 Quick Opening Closures

7.2.4.5.1.1 A quick opening closure is a pressure-containing component which is used for repeated access to the interior of a piping system. Pig trap launcher and receiver barrel closures are examples of quick opening closures. It is not the intent to impose the requirements of a specific design method on the designer and manufacturer of a quick opening closure.

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7.2.4.5.1.2 Quick opening closures shall have pressure and temperature ratings equal to, or in excess of, the design requirements for the piping system in which it will be installed.

7.2.4.5.1.3 Quick opening closures shall be equipped with safety locking devices in compliance with paragraph UG-35(b), Section VIII, Division 1, ASME BPV Code.

7.2.4.5.1.4 Weld end preparation shall be in accordance Figure I4, Appendix I, ANSI B31.8.

7.2.4.5.2 Closure Fittings

Closure fittings commonly referred to as “weld caps” shall be designed and manufactured in accordance with ANSI B16.9 or MSS SP-75.

7.2.4.5.3 Closure Heads

7.2.4.5.3.1 Closure heads such as flat, ellipsoidal, spherical, or conical heads are allowed for use. Heads will be designed in accordance with Section VIII, Division 1, BPV Code. The maximum allowable stresses for materials used in these closure heads shall not exceed 50% SMYS.

7.2.4.5.3.2 Welds in the construction of closure heads shall be inspected with the requirements in Sections V, VIII, and IX, ASME BPV Code.

7.2.4.5.3.3 Pressure and temperature ratings for closure heads shall be equal to or greater than the design pressure of the pipeline.

7.2.4.5.4 Fabricated Closures

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7.2.4.5.4.1 Orange-peel bull plugs and orange-peel swages are prohibited on pipeline components operating at stress levels at or above 20% SMYS.

7.2.4.5.4.2 Flat closures on pipe larger than NPS 3 shall be designed in accordance with Section VIII, Div. 1, BPV Code.

7.2.4.5.5 Bolted Blind Flange Connections

Bolted blind flanges connections shall conform to paragraph 831.2, ANSI B31.8.

7.2.5 Reinforcement of Welded Branch Connections

7.2.5.1 General Requirements

7.2.5.1.1 Single branch connections or a series of branch connections in a header assembly must be designed to control the stress levels in the pipe within safe limits. Stresses in the remaining pipe wall due to the opening in the pipe or header, shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, vibration, etc, must be considered.

7.2.5.1.2 The reinforcement required in the crotch section of a welded branch connection shall be determined by the rule that the metal area available for reinforcement shall be equal to or greater than the required area. Figure F5 Appendix F, ANSI B31.8 provides appropriate guidance in the interpretation and use of this requirement. Assistance in the use of this requirement can be provided by inspection personnel qualified to National Board Inspection Code or API Standard 510.

7.2.5.1.3 The required cross-sectional area, A_R , Figure F5 is defined as the product of d times t :

$$A_R = dt$$

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where;

d = the greater of the length of the finished opening in the header wall measured parallel to the axis of the run or the inside diameter of the branch connection.

t = the nominal header wall thickness required for the design pressure and temperature (Do not include corrosion allowance).

7.2.5.1.4 The area available for reinforcement shall be the sum of:

- (1) The cross sectional area resulting from excess thickness available in the header thickness [$>t$] which lies within the reinforcement area;
- (2) The cross sectional area resulting from any excess thickness available in the branch wall thickness over minimum thickness required for the branch which lies within the reinforcement area;
- (3) The cross sectional area of all weld-reinforcing metal which lies within the reinforcement area including solid weld metal attached to the header or branch, or both.

7.2.5.1.5 The area of reinforcement is shown in Figure F5, ANSI B31.8, and is defined as a rectangle whose length shall extend a distance d on each side of the traverse center line of the finished opening and whose width shall extend a distance of 2-1/2 times the header wall thickness on each side of the header wall, except that in no case shall it extend more than 2-1/2 times the thickness of the branch wall from the outside surface of the header or of the reinforcement, if any.

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7.2.5.1.6 The material of any added reinforcement shall have an allowable working stress at least equal to that of the header wall, except that material of lower allowable stress may be used if the area is increased in direct ratio of the allowable stresses for header and reinforcement material, respectively.

7.2.5.1.7 The material used for ring or saddle reinforcement may be a different specification from the pipe, provided the cross-sectional area is made in direct proportion to the relative strength of the pipe and reinforcement materials at the operating temperatures with comparable welding qualities. No credit shall be taken for the additional strength of material having a higher strength than the part to be reinforced.

7.2.5.1.8 Vent holes shall be provided in rings or saddles which cover the weld between branch and header to reveal leakage in the weld between branch and header and to provide venting during welding and heat treating operations. Vent holes should be plugged during operation to prevent crevice corrosion.

7.2.5.1.9 Ribs and gussets shall not be considered to contribute to reinforcement of branch connections, but these attachments may be used as stiffeners.

7.2.5.1.10 The branch shall be attached by a weld for the full thickness of the branch or header wall plus a fillet weld, W_1 , as shown in Figs. I1 and I2, Appendix I, ANSI B31.8. Concave fillet welds are preferred to minimize corner stress concentrations. When a full fillet weld is not used, the edge of the reinforcement should be chamfered at approximately 45 degrees to merge with the edge of the fillet.

7.2.5.1.11 Reinforcement rings and saddles shall be accurately fitted to parts where attached. Figures I2 and I3, Appendix I, ANSI B31.8 show acceptable forms of attachment.

7.2.5.1.12 Branch connections attached at an angle less than 85 degrees to the run become progressively weaker as the angle becomes

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less. Any such design must be given individual study and sufficient reinforcement must be provided to compensate for the inherent weakness of such construction. The use of encircling ribs to support the flat or reentering surfaces is permissible, and may be included in the strength calculations. The designer is cautioned that stress concentrations near the ends of partial ribs, straps, or gussets may defeat their reinforcing value.

7.2.5.2 Special Requirements

7.2.5.2.1 In addition to the requirements in paragraph 7.2.5.1, branch connections must meet the special requirements of the following paragraphs as shown in the table below:

REINFORCEMENT OF WELDED BRANCH CONNECTIONS, SPECIAL REQUIREMENTS

Ratio of Design Hoop Stress to Header SMYS in Header	Ratio of Nominal Branch Diameter to Nominal Diameter		
	25 or Less	More Than 25% Through 50%	>50%
20% or less	g	g	h
>20% to 50%	d, i	i	h, i
>50%	c, d, e	b, e	a, c, f

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- (a) Smoothly-contoured wrought-steel tees of proven design are preferred. When tees cannot be used, the reinforcing member shall extend around the circumference of the header. Pads, partial saddles, or other types of localized reinforcement are prohibited.
- (b) Smoothly-contoured tees of proven design are preferred. When tees are not used, the reinforcing member should be a complete encirclement type, but pad, saddle, or welding outlet fitting types may be used.
- (c) The reinforcement member may be the complete encirclement, pad, saddle, or welding outlet fitting type. Edges of reinforcement members should be tapered to header thickness. Legs of fillet welds joining the reinforcing member and header shall not exceed the thickness of the header.
- (d) Reinforcement calculations are not required for openings 2 in. and smaller in diameter. However, vibration, bending stresses, and tensile loads must be considered.
- (e) All welds joining the header, branch, and reinforcing member shall be equivalent to Figures I1 and I2, Appendix I, ANSI B31.8.
- (f) Inside edges of the finished opening shall, whenever possible, be rounded to a 1/8 in. radius. If the encircling member is thicker than the header, the ends shall be tapered down to the header thickness and continuous fillet welds made.
- (g) Reinforcement of openings is not mandatory. However, reinforcement may be required for special cases involving pressures over 100 psi, thin wall pipe, or severe external loads.
- (h) If a reinforcement member is required, and the branch diameter is such that a localized type of reinforcement member would extend around more than half the circumference of the header, then a complete encirclement type of reinforcement member shall be used, regardless of the design hoop stress, or a

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smoothly contoured wrought steel tee of proven design may be used.

- (i) The reinforcement may be any type meeting the requirements in General Requirements in this section

7.2.6 Reinforcement of Multiple Openings

7.2.6.1.1 When two or more adjacent branches are spaced at less than two times their average diameter (effective areas of reinforcement overlap), the groups of openings must be reinforced. Reinforcing metal shall be used as a combined reinforcement, the strength shall equal the combined strengths of the reinforcements required for the separate openings. No portion of a cross section shall be applied to more than one opening or shall be evaluated more than once in a combined area.

7.2.6.1.2 When more than two adjacent openings are to be provided with a combined reinforcement, the minimum distance between centers of any two of these openings shall preferably be at least 1.5 times their average diameter, and the area of reinforcement between them shall be at least equal to 50% of the total required for these two openings on the cross section being considered.

7.2.6.1.3 When the distance between centers of two adjacent openings is less than $1 \frac{1}{3}$ times their average diameter, no credit for reinforcement shall be given for any metal between the two openings.

7.2.6.1.4 Any number of closely spaced adjacent openings in any arrangement may be reinforced as if the group were treated as one assumed opening of a diameter enclosing all such openings.

7.2.7 Extruded Outlets

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7.2.7.1 The rules in this section apply to steel extruded outlets in which the reinforcement is integral.

7.2.7.2 An extruded outlet is defined as an outlet where the extruded lip at the outlet has a height above the surface of the run which is equal to or greater than the radius of curvature of the external contoured portion of the outlet. (See Figs. F1 through F4 and nomenclature, Appendix F, ANSI B31.8)

7.2.7.3 These rules do not apply to any nozzles or branch connections where additional nonintegral material is applied in the form of rings, pads, or saddles.

7.2.7.4 These rules apply only to cases where the axis of the outlet intersects and is perpendicular to the axis of the run.

7.2.7.5 Figures F1 through F4, Appendix F, ANSI B31.8 define the pertinent dimensions and limiting conditions.

7.2.7.6 *Required Area.* The required area is defined as

$$A = K_t D_0$$

where

$K = 1.00$ when $d/D > 0.60$

$= 0.6 + 2/3 d/D$ when $d/D > 0.15$ and not exceeding 0.60

$= 0.70$ when d/D is equal to or less than 0.15

The design must meet the criterion that the reinforcement area defined in 7.2.7.7 below is not less than the required area.

7.2.7.7 *Reinforcement Area.* The reinforcement area shall be the sum of areas $A_1 + A_2 + A_3$ as defined:

7.2.7.7.1 Area A_1 is the area lying within the reinforcement zone resulting from any excess thickness available in the run wall, i.e.,

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$$A_1 = D_0 (T_r - t_r)$$

7.2.7.8 Area A_2 is the area lying within the reinforcement zone resulting from any excess thickness available in the branch pipe wall, i.e.,

$$A_2 = 2L (T_b - t_r)$$

7.2.7.8.1 Area A_3 is the area lying within the reinforcement zone resulting from excess thickness available in the extruded outlet lip, i.e.,

$$A_3 = 2r_o (T_0 - T_b)$$

7.2.7.9 Reinforcement of Multiple Openings. The rules in paragraph 7.2.6 shall be followed except that the required area and reinforcement area shall be given in paragraph 7.2.7.

7.2.7.10 The manufacturer shall be responsible for establishing and marking on the section containing extruded outlets, the design for pressure and temperature meets Code requirements.

7.3 EXPANSION AND FLEXIBILITY

7.3.1 General

This section is applicable to above ground piping only and covers all classes of materials permitted by ANSI B31.8 up to 450° F.

7.3.2 Amount of Expansion

The thermal expansion of more common materials used for piping can be determined from the following table. The expansion to be considered is the difference between the expansion for the maximum expected operating temperature and the expected average erection temperature. For materials not included in this Table, or for precise calculations, reference should be made to authoritative source data, such as publications of the National Institute of Standards and Technology.

7.3.2.1 TABLE - THERMAL EXPANSION OF PIPING MATERIALS

Carbon and Low Alloy High Tensile and Wrought Iron	
Temperature, °F	Total Expansion, in./1000 ft, Above 32°F
32	0.0
60	0.2
100	0.5
125	0.7
150	0.9
175	1.1
200	1.3
225	1.5
250	1.7
300	2.2
350	2.6
400	3.0
450	3.5

7.3.3 Flexibility Requirements

7.3.3.1 Piping systems shall be designed to have sufficient flexibility to prevent thermal expansion or contraction from causing excessive stresses in piping material, excessive bending or unusual loads at joints, or

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undesirable forces or moments at points of connection to equipment or at anchorage or guide points. Formal calculations shall be required only where reasonable doubt exists as to the adequate flexibility of the system.

7.3.3.2 Flexibility shall be provided by the use of bends, loops, or offsets. Provision shall be made to absorb thermal changes by the use of expansion joints or couplings of the slip-joint type or expansion joints of the bellows type. If expansion joints are used, anchors or ties of sufficient strength and rigidity shall be installed to provide for end forces due to fluid pressure and other causes.

7.3.3.3 In calculating the flexibility of a piping system, the system shall be treated as a whole. The significance of all parts of the line and all restraints, such as solid supports or guides, shall be considered.

7.3.3.4 Calculations shall account for stress intensification factors found to exist in components other than straight pipe. In the absence of applicable data, the flexibility factors shown in Table E1, Appendix E, ANSI B31.8 may be used.

7.3.3.5 Properties of pipe and fittings for these calculations shall be based on nominal dimensions with a joint factor E of 1.00.

7.3.3.6 The total range in temperature shall be used in all expansion calculations, whether piping is cold-sprung or not. In addition to the expansion of the line itself, the linear and angular movements of the equipment to which it is attached shall be considered.

7.3.3.7 Cold-Springing. To modify the effect of expansion and contraction, runs of pipe may be cold-sprung.

7.3.3.8 Flexibility calculations shall be based on the modulus of elasticity E_C at ambient temperature.

7.4 COMBINED STRESS CALCULATIONS

7.4.1 Stresses and reactions due to expansion shall be investigated at all significant points of a pipeline or piping system.

7.4.2 Expansion stresses shall be combined in accordance with the following formula:

$$S_E = (S_b^2 + 4S_t^2)^{1/2}$$

where;

S_E = combined expansion stress, psi

S_b = resultant bending stress, psi = iM_b/z

S_t = torsional stress, psi = $M_t/2z$

M_b = resultant bending moment, lb-in.

M_t = torsional moment, lb-in.

z = section modulus of pipe, in.³

i = stress intensification factor (Appendix E, ANSI B31.8)

The maximum combined expansion stress range S_E shall not exceed 0.72S where S is specified minimum yield strength (SMYS), psi subject to further limitations in the following paragraph.

7.4.3 The total of the following shall not exceed S:

7.4.3.1 The combined stress due to expansion S_E ;

7.4.3.2 The longitudinal pressure stress;

7.4.3.3 The longitudinal bending stress due to external loads, such as weight of pipe and contents, wind, etc.

7.4.4 The sum of paragraphs 7.4.2 and 7.4.3 shall not exceed 0.75S.

7.4.5 The reaction R' shall be obtained as follows from the reactions R derived from the flexibility calculations:

$$R' = (1 - 2/3C_S) R$$

when C_S is less than 0.6; $R' = C_S$ is between 0.6 and 1.0 where;

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C_S = The cold-spring factor varying from zero for no cold-spring to 1.0 for 100% cold-spring.

R = Maximum reaction corresponding to the full expansion range based on E_C .

E_C = The modulus of elasticity in the cold condition.

R' = Maximum reaction for the line after cold-springing; the reactions so computed shall not exceed limits which the attached equipment or anchorage is designed to sustain.

7.5 SUPPORTS AND ANCHORAGE FOR EXPOSED PIPING

7.5.1 General

Piping and equipment shall be supported to prevent or dampen excessive vibration, and shall be anchored to prevent undue strains on connected equipment.

7.5.2 Provisions for Expansion

Support, hangers, and anchors should be installed to not interfere with the free expansion and contraction of the piping between anchors.

7.5.3 Materials, Design, and Installation

All permanent hangers, supports, and anchors shall be fabricated from durable incombustible materials. The assemblies shall be designed and installed with good engineering practice for the service conditions.

7.5.4 Forces on Pipe Joints

All exposed pipe joints shall be able to sustain the maximum end force due to the internal pressure, i.e., the design pressure, psi, times the internal area of the pipe, in.², as well as any additional forces due to temperature expansion or contraction or to the weight of pipe and contents.

7.5.5 Attachment of Supports or Anchors

7.5.5.1 Structural supports or anchors may be welded directly to the pipe if the pipe is designed to operate at a hoop stress less than 50% SMYS. Proportioning and welding strength requirements shall conform to standard structural practice.

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7.5.5.2 If the pipe is designed to operate at a hoop stress greater than 50% SMYS, support of the pipe shall be furnished by a member which completely encircles the pipe. Where it is necessary to provide positive attachment, as at an anchor, the pipe may be welded to the encircling member only; the support shall be attached to the encircling member and not to the pipe. The connection of the pipe to the encircling member shall be by continuous welds, rather than intermittent ones.

7.6 SUPPORTS AND ANCHORAGE FOR EXPOSED PIPING

7.6.1 General

Bends or offsets in buried pipe cause longitudinal forces which must be resisted by anchorage at the bend, by restraint due to friction of the soil, or by longitudinal stresses in the pipe.

7.6.2 Anchorage at Bends

If the pipe is anchored by bearing at the bend, care shall be taken to distribute the load on the soil so that the bearing pressure is within safe limits for the soil involved.

7.6.3 Restraint Due to Soil Friction

Calculations shall be made and anchorage installed if there is doubt as to the adequacy of restraint friction.

7.6.4 Forces on Pipe Joints

If anchorage is not provided at the bend, pipe joints which are close to the points of thrust origin shall be designed to sustain the longitudinal pullout force. If such provision is not made in the manufacture of the joints, suitable bracing or strapping shall be provided.

7.6.5 Supports for Buried Piping

7.6.5.1 In pipelines which are highly stressed from internal pressure, uniform and adequate support of the pipe in the trench is essential. Unequal settlements may produce added bending stresses in the pipe. Lateral thrusts at branch connections may greatly increase the stresses in the

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branch connection itself, unless the fill is thoroughly consolidated or other provisions made to resist the thrust.

7.6.5.2 Rock shield shall not be draped over the pipe unless suitable backfill and padding are placed in the ditch to provide a continuous and adequate support of the pipe in the trench. A 12-inch cylinder of rock free backfill shall envelope the pipe in sections with rocky excavations.

7.6.5.3 When openings are made in a consolidated backfill to connect new branches to connect new branches to an existing line, care must be taken to provide firm foundation for both the header and the branch, to prevent both vertical and lateral movements.

7.6.6 Interconnection of Underground Piping

Underground lines are subjected to longitudinal stresses due to changes in pressure and temperature. For long lines, the friction of the earth will prevent changes in length from these stresses, except for several hundred feet adjacent to bends or ends. At these locations, the movement, if unrestrained, may be of considerable magnitude. If connections are made at such a location to a relatively unyielding line or other fixed object, it is essential that the interconnection shall have ample flexibility to care for possible movement, or that the line shall be provided with an anchor sufficient to develop the forces necessary to limit the movement.

8 DESIGN, INSTALLATION, AND TESTING

8.1 DESIGN, INSTALLATION, AND TESTING

8.1.1 GENERAL PROVISIONS

8.1.1.1 This Company Plant Engineering Specification with correct interpretation and application of ANSI B31.8 Code complimented by the requirements in 49CFR192 are intended to be adequate for public safety under all conditions encountered in the gas industry. However, additional stresses in the form of long self-supported spans, unstable ground, mechanical or sonic vibration, weight of special attachments, earthquake

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induced stresses, and thermal stresses must be considered and correctly engineered to minimize safety problems.

8.1.1.2 A conservative determination of the Location Class is extremely important and provides a method of assessing the degree of exposure of the pipeline to outside forces and resultant damage. Activities of people along the pipeline are the most significant factor in damage to the pipeline. These activities include, but are not limited to, construction of services associated with infrastructural requirements, i.e., water, gas, electrical, sewage, drainage, buried power and communication cables, streets and roads.

8.1.2 BUILDINGS INTENDED FOR HUMAN OCCUPANCY

8.1.2.1 Company's gas transmission pipelines have been designated as Location Class 3 . A Location Class 3 is any 1 mile section that has 46 or more buildings intended for human occupancy except when a Location Class 4 prevails. A Location Class 3 is intended to reflect areas such as suburban housing developments, shopping centers, residential areas, industrial areas, and other populated areas not meeting Location Class 4 requirements.

8.1.2.2 Location Class 4 includes areas where multistory buildings are the rule, traffic is heavy, and numerous underground utilities exist. Multistory means 4 stories above ground without regard to basement (s).

8.1.3 CONSIDERATIONS NECESSARY FOR CONCENTRATIONS OF PEOPLE IN LOCATION CLASS 1 OR 2

8.1.3.1 Location Class 2 are locations in population fringe areas around towns or cities, industrial areas, ranch or country estates, etc.

8.1.3.2 Pipelines near places of public assembly or concentrations of people such as churches, schools, multiple dwelling unit buildings, hospitals, or recreational areas of an organized nature in Location Class 1 or 2 shall meet requirements for Location Class 3. The above restriction to pipelines in Location Class 2 places most ENGINEERING SERVICES, LP Company pipelines in Location Class 3.

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8.1.4 INTENT

In the design of future Company pipelines, future non-Company planning and development should be considered that may promote a pipeline from Location Class 3 to 4. This consideration shall be taken in the design, installation, and testing of a new pipeline.

8.2 STEEL PIPE**8.2.1 Steel Pipe Design Formula**

8.2.1.1 Barlow's Formula for circumferential (hoop) stress in thin-walled pressure vessels is the basis for determining the design pressure in steel gas piping systems. The basic Barlow Formula is modified to include factors for Location Class (F), longitudinal joint factor (E), and temperature derating factor (T). The formula with all factors included is:

$$P = 2St/D (FET)$$

where;

- P = Design pressure, psig.
- S = Specified minimum yield strength, psi.
- t = Nominal wall thickness, inches.
- D = Nominal outside diameter of pipe, inches.
- F = Design factor from Location Class.
- E = Longitudinal joint factor.
- T = temperature derating factor

The design formula can be simplified to:

$$P = St/D$$

when the following criteria are met:

- (a) Location Class is 3 with design factor of 0.5.
- (b) Line pipe is purchased to API 5L (seamless, ERW, SAW).
- (c) Design temperature is 250⁰F or less.

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These design conditions are met for all Company pipelines.

8.2.1.2 The basic Barlow's Formula can be rearranged to solve for thickness and hoop stress which become important parameters in determining the strength of corroded line pipe and repair requirements, if any. For Company gas transmission pipelines meeting the above criteria, the formulae are:

8.2.1.2.1 $t = PD/2S$

Where t is the minimum thickness required to contain operating pressure (P) in a pipeline (D) with stress (S).

8.2.1.2.2 $S = S_H = PD/2t$

Where S is the hoop stress in a pipeline at given pressure, diameter, and thickness.

8.2.1.3 Fracture Control and Arrest

Fracture toughness criteria shall be specified to control fracture propagation when a pipeline is designed to operate either at:

- (a) A hoop stress over 40% through 80% of SMYS in sizes NPS 16 or larger, or at
- (b) A hoop stress over 72% through 80% of SMYS in sizes smaller than NPS 16.

Control can be achieved by assuring that the pipe has adequate ductility and either specifying adequate toughness or installing crack arrestors on the pipeline to stop propagation.

8.2.1.3.1 *Brittle Fracture Control.* Fracture toughness testing shall be performed in accordance with the testing procedures of the supplementary requirements SR5 or SR6 of API 5L. The average shear value of the fracture appearance of the test specimens from

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each heat shall not be less than 35% and the all heat average shall not be less than 50% shear when Charpy V-notch testing, based on full-sized Charpy specimens, is specified. Alternatively, at least 80% of the heats shall exhibit a fracture shear appearance of 40% or more when drop-weight tear testing is specified.

8.2.1.3.1.1 Ductile Fracture Arrest. Pipe shall be tested in accordance with the procedures of supplementary requirement SR5 of API 5L. The all heat average of the Charpy energy values shall meet or exceed the energy value calculated using one of the following equations that have been developed in various pipeline research programs.

- (a) Battelle Columbus Laboratories (BCL)
(AGA)

$$\text{CVN} = 0.0108\sigma^2 R^{1/3} t^{1/3}$$

- (b) American Iron and Steel Institute (AISI)

$$\text{CVN} = 0.0345\sigma^{3/2} R^{1/2}$$

- (c) British Gas Council (BCG)

$$\text{CVN} = 0.0315\sigma R/t^{1/2}$$

- (d) British Steel Corporation (BSC)

$$\text{CVN} = 0.00119\sigma^2 R$$

where;

CVN = full-size Charpy V-notch
absorbed energy, ft-lb

σ = hoop stress, ksi

R = pipe radius, inches

t = wall thickness, inches

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8.2.1.3.1.2 Mechanical Crack Arrestors shall be placed at intervals along the pipeline if required and consist of sleeves, wire-rope wrap, heavy-wall pipe which have been shown to provide effective means of arresting ductile fracture.

8.2.1.4 Limitations on Design Pressure, P The design pressure, P, shall not exceed 85% of the mill test pressure, unless the pipe is retested in the field. P may not exceed 85% of the second pressure.

8.2.1.5 Limitations on Specified Minimum Yield Strength

If the pipe to be installed on a Company pipeline project is not new pipe purchased to API 5L requirements, the value of S may be determined in one of the following methods:

8.2.1.5.1.1 S value for reused pipe which is removed from a pipeline and reinstalled in the same pipeline at another location.

8.2.1.5.1.2 For pipe of unknown specification, use an S value of 24,000 psi in lieu of a known SMYS.

8.2.1.6 Additional Requirements for Nominal Wall Thickness, t.

8.2.1.6.1 Additional wall thickness may be required for loading due to transportation of the pipe during construction, weight of water during testing, and soil loading and other secondary loads during operation. Consideration should also be given to welding or mechanical joining requirements.

8.2.1.6.2 The pipe wall thickness shall not be reduced to less than 90% of the design thickness under any circumstances including transportation, construction, operation, and maintenance.

8.2.1.7 Design Factors, F, and Location Classes

All Company gas transmission pipelines meet the requirements of Location Class 3 with a Design Factor, **F = 0.50**.

8.2.2 Pipelines on Bridges

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Company-operated pipelines will be designed with an F factor equal to 0.50 for installations where the pipe is supported by railroad, vehicular, pedestrian, or pipeline bridges.

8.2.3 Protection of Pipelines From Hazards

Pipelines which must be installed in locations where high loading may occur due to natural hazards shall be constructed with increased wall thickness, moving soil containment, erosion prevention, and weight/anchor installation.

**8.2.4 Cover, Clearance, and Casing Requirements for Buried Steel Pipelines.
Cover Requirements for Pipelines:**

Normal excavation - 30 inches

Rock excavation - 24 inches

8.2.4.1 Clearance Between Pipelines and Other Underground Structures

At least twelve (12) inches of clearance must be maintained between ENGINEERING SERVICES, LP pipelines and other underground structures either Company or foreign. The installation of casing, bridging, or insulating material shall be installed if 12-inch clearance cannot be assured.

8.2.4.2 Casing Requirements Under Railroads, Highways, Roads, or Streets

Casings shall be designed to withstand all expected loads. Casings shall be designed with:

Design Factor (F) = 0.50

Casing-to-pipe insulation

End seals

Cathodic protection

8.2.5 Installation of Steel Pipelines**8.2.5.1 Construction Specifications**

All work completed in accordance with this specification will require complete construction specifications which includes ANSI B31.8. The construction specifications shall cover all phases of the work and shall be

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in sufficient detail to cover the requirements in this specifications, ANSI B31.8, and 49CFR192.

8.2.5.2 Inspection Provisions

8.2.5.2.1 Company will provide complete inspection coverage for all pipeline construction and maintenance projects. Inspectors will be qualified by both experience and training. Minimum qualifications for inspectors shall be the same qualifications as API 570, “Inspection, Repair, Alteration, and Rerating of In-Service Systems”. These requirements include:

- (a) A degree in engineering plus one year of experience in the design, construction, repair, operation, or inspection of piping systems.
- (b) A 2-year certificate in engineering or technology from a technical college plus 2 years of experience in the design, construction, repair, operation, or inspection of piping systems.
- (c) The equivalent of a high school education plus 3 years of experience in the design, construction, repair, operation, or inspection of piping systems.
- (d) Five years of experience inspecting in-service piping systems.

8.2.5.2.2 Piping inspection for Company construction projects shall insure quality workmanship with frequent on-site visits. Major responsibilities include:

- (a) Inspect surface of pipe for serious surface defects prior to coating operation.
- (b) Inspect surface of pipe coating prior to lowering-in.
- (c) Inspect fitup of joints prior to welding.
- (d) Inspect root bead prior to first hot pass.
- (e) Inspect completed welds prior to coating.
- (f) Inspect condition of ditch bottom prior to lowering in.

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- (g) Inspect fit of pipe in ditch before backfilling.
- (h) Inspect all repairs, replacements, or changes prior to backfilling.
- (i) Supervise and approve nondestructive testing of welds and electrical testing of welds.
- (j) Inspect backfill material prior to use and observe backfill procedure to assure no damage to the coating during backfilling.

8.2.5.3 Bends, Elbows, and Miters in Steel Pipelines

8.2.5.3.1 Changes in direction and elevation may be made by the use of bends and elbows.

8.2.5.3.2 Wrinkle and miter bends are not allowed on Company pipelines.

8.2.5.3.3 The maximum degree of field cold bends in pipe sizes NPS 12 and larger may be determined by the table in paragraph 841.231 (b), ANSI B31.8. Field cold bends may be made with a shorter radius provided all other requirements of the section are met. Wall thickness after bending shall meet minimum requirements of the specification. Circumferential welds in the bend section shall be radiographed.

8.2.5.4 Pipe Surface Requirements Applicable to Pipelines to Operate at a Hoop Stress of 20% or More of the Specified Minimum Yield Strength**8.2.5.4.1 Detection of Gouges and Grooves**

8.2.5.4.1.1 Gouges, grooves, and notches are an important cause of pipeline failures. All defects of this nature must be prevented or repaired. Precautions shall be taken during manufacture, hauling, and installation to prevent the gouging or grooving of pipe.

8.2.5.4.1.2 Field inspection of coated pipe is required prior to lowering-in to minimize installation of pipe with unacceptable grooves or gouges.

8.2.5.4.2 Field Repair of Gouges and Grooves

8.2.5.4.2.1 Unacceptable grooves or gouges shall be removed and repaired.

8.2.5.4.2.2 Grooves or gouges may be removed by grinding to a smooth contour provided that the wall thickness is not reduced to less than 90% of design thickness.

8.2.5.4.2.3 Patch repair is prohibited. Damaged portion shall be cut out as a cylinder and replaced.

8.2.5.4.3 Dents

8.2.5.4.3.1 A dent is depression which produces a significant reduction in the diameter of the pipe. Depth of the dent shall be measured as the gap between the lowest point of the dent and the original contour of the pipe.

8.2.5.4.3.2 A dent which contains a stress raiser such as a scratch, gouge, groove, or arc burn shall be removed and replaced with a new cylinder of identical pipe.

8.2.5.4.3.3 All dents which occur in longitudinal or circumferential welds shall be removed and repaired with a new pipe section.

8.2.5.4.4 Arc Burns

Arc strikes may be removed by grinding if the wall thickness is not reduced to less than 90% design.

8.2.5.5 Miscellaneous Operations Involved in the Installation of Steel Pipelines

8.2.5.5.1 Installation of Pipe in the Ditch

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Stresses induced into the pipe during construction must be minimized. Pipe shall lay in the ditch with application of outside forces.

8.2.5.5.2 Backfilling

8.2.5.5.2.1 Backfilling shall be performed to provide firm, continuous support under the pipe.

8.2.5.5.2.2 When backfilling with material containing rocks, no rocks shall be closer to the pipe than 12 inches. A “rock-free” cylinder of sand or dirt shall be placed around the pipe maintaining the required 12 inches of small-particle backfill material. In addition, rock shield are required when the backfill material contains rocks over 4 inches in diameter.

8.2.5.6 Hot Taps

All hot taps shall be installed by trained and experienced crews in accordance with Company Safety and Health Standards and written engineering specifications and procedures which are unique for each job.

8.2.5.7 Precautions to Avoid Explosions of Gas-Air Mixtures or Uncontrolled Fires During Construction Operations

8.2.5.7.1 Gas/electric welding operations and cutting with torches can be safely performed on pipelines and associated equipment if the pipeline is completely full of gas or air that is free of combustible material.

8.2.5.7.2 The following procedure is recommended for welding or cutting on a pipeline which is full of gas:

- (a) Maintain a slight flow of gas.
- (b) Control gas pressure at work site by suitable means.
- (c) Close all slots or open ends with tape, tightly fitted canvas, or other suitable materials immediately after a cut is made.

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- (d) Do not permit two openings to remain uncovered at the same time.

8.2.5.7.3 Welding, cutting, or other operations that could be a source of ignition shall not be done on a pipeline that contains air, if connected to a gas source. Purging, combustible-mixture testing, and use of isolation valves can be used to minimize explosive mixtures when welding or cutting is necessary on the pipeline.

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8.2.5.7.4 Paragraph 841.275, ANSI B31.8 provides acceptable methods for purging air in pipelines prior to being returned or placed in gas service. The first method is preferred and should be used when possible: Introduce a moderately rapid and continuous flow of gas into one end of the line and vent air out the other end. The gas flow shall be continued without interruption until the vented gas is free of air.

8.2.6 Testing After Construction**8.2.6.1 General Provisions**

8.2.6.1.1 All piping systems shall be pressure tested after construction to the requirements in ANSI B31.8 except for pretested fabricated assemblies, pretested tie-in sections, and tie-in connections.

8.2.6.1.2 Radiography in lieu of hydrotesting may be substituted for circumferential welds of welded tie-in connections not pressure tested after construction.

8.2.6.2 Test Required to Prove Strength of Pipelines to Operate at Hoop Stresses of 30% or More of the Specified Minimum Yield Strength of the Pipe

8.2.6.2.1 All pipelines to be operated at a hoop stress of 30% or more of the SMYS shall be pressure tested to a minimum of 1.5 times the design pressure. The test duration shall be four (4) hours to prove strength after construction and before being placed in operation.

8.2.6.2.2 Testing fluid shall be water. Air and gas are not permissible test media for Company-operated Location Class 3 pipelines.

8.2.6.2.3 Records

Company shall maintain records showing the hydrotest procedures and the data developed in establishing its MAOP. These records shall be filed for the useful life of each pipeline in the Company's operation.

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8.2.6.3 Leak Tests for Pipelines to Operate at 100 psi or More.

8.2.6.3.1 Leak test shall be performed on all pipelines after construction and prior to being placed in operation.

8.2.6.3.2 Leak test shall be made at a pressure to produce 20% SMYS and the line shall be walked while this pressure is maintained on the pipeline.

8.3 COMPRESSOR STATIONS**8.3.1 Compressor Station Equipment-Gas Treating Facilities**

8.3.1.1 Liquid separators shall be constructed in accordance with ANSI B31.8 with Location Class 4 requirements (Design Factor = 0.5) when using API 5L pipe or equivalent, ANSI B31.8 specified fittings, and no internal welding.

8.3.1.2 Liquid separators when construction of materials other than 8.6.1.1 shall be constructed in accordance with Section VIII, Division 1, ASME Boiler and Pressure Vessel Code.

8.3.1.3 Safety Devices**8.3.1.3.1 Emergency Shutdown Facilities**

Each transmission compressor station shall be provided with an emergency shutdown system to block gas from the station and the station gas piping can be blown down.

8.3.2 Pressure Limiting Requirements in Compressor Stations

Pressure relief devices shall be installed and maintained to assure the MAOP of station piping and equipment is not exceeded by more than 10%.

8.3.3 Compressor Station Piping**8.3.3.1 Specifications for Gas Piping**

All compressor station gas piping shall be steel with a design factor, $F = 0.5$.

8.3.3.2 All compressor gas piping shall be pressure tested to 1.5 times the design pressure.

8.3.3.3 Emergency valves and controls shall be identified by signs. All important gas pressure piping shall be identified by signs or color codes.

8.3.3.4 Pressure-limiting regulators shall be installed to prevent the normal operating pressure from exceeding 1.25 times the normal pressure and the MAOP from exceeding 1.10 times the MAOP.

8.3.3.5 Air Receivers

Air receivers shall be constructed in accordance with Section VIII, ASME BPV Code.

8.3.3.6 Lubricating Oil Piping

Lubricating oil piping shall be constructed in accordance with ANSI B31.3.

8.3.3.7 Water Piping Water piping shall be constructed in accordance with ANSI B31.1.

8.3.3.8 Steam Piping

Steam piping shall be constructed in accordance with ANSI B31.1.

8.3.3.9 Hydraulic Piping

Hydraulic piping shall be constructed in accordance with ASME B31.3.

8.4 CONTROL AND LIMITING OF GAS PRESSURE

8.4.1 Basic Requirement for Protection Against Accidental Overpressuring

Every pipeline or compressor station shall be equipped with suitable pressure relieving or pressure limiting devices if the equipment is connected to a gas source where failure of pressure control might result in a pressure which would exceed the MAOP of the facility.

8.4.2 Control and Limiting of Gas Pressure in Pipelines

8.4.2.1 Types of protective devices to prevent overpressuring include:

- (a) Spring-loaded relief valves meeting the provision of Section VIII, ASME BPV Code.
- (b) Pilot-loaded back-pressure regulators used as relief valves.
- (c) Rupture disks meeting the provisions of Section VIII, Division 1, ASME BPV Code.

8.4.2.2 Maximum Allowable Operating Pressure for Steel Pipelines

The maximum allowable operating pressure (MAOP) shall not exceed the lesser of either:

- (a) The design pressure of the weakest element of the pipeline.
- (b) The pressure obtained by dividing the pressure to which the pipeline is tested after construction by the appropriate factor for the Location Class involved. For Company pipelines, test pressure divided by 1.50.
- (c) The maximum safe pressure for the pipeline based on its operating and maintenance history.

8.4.2.3 Qualification of a Steel Pipeline to Establish the MAOP

- (a) MAOP shall be determined by hydrostatic testing of the pipeline.
- (b) MAOP shall be limited to the pressure obtained by dividing the test pressure by the appropriate test factor for Location Class 3, i.e., 2.0.
For Company pipelines: Test Pressure/2.0
- (c) Test pressure for MAOP calculations shall be the test pressure at the high elevation point of the minimum strength test section and shall not be higher than the pressure required to produce a stress equal to the yield strength as determined by testing.
- (d) Records shall be maintained as long as the pipeline remains in service.
- (e) Determine that all valves, flanges, and other pressure related components have adequate ratings.

8.4.3 Requirements for Design of Pressure Relief and Pressure Limiting Installations**8.4.3.1** Pressure relief or pressure limiting devices, except rupture disks, shall:

- (a) Be constructed of materials which are corrosion resistant to both internal and external corrodents;
- (b) Have valves and valve seats which are designed for smooth operation in all positions;
- (c) Be designed and installed to be operated to determine if the valve is free, can be tested to determine the pressure at which they will operate, and can be tested for leakage in the closed position.

8.4.3.2 Rupture disks shall meet the requirements for design in Section VIII, Division 1, ASME BPV Code.

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8.4.3.3 The size of the openings, pipe, and fittings located between the system to be protected and pressure-relieving device and the vent line shall be adequate size to prevent hammering of the valve and to prevent impairment of relief capacity.

8.4.3.4 Precautions shall be taken to prevent unauthorized operation of any stop valve which will make a relief valve inoperative. Acceptable methods include:

- (a) Lock the stop valve in the open position.
- (b) Install duplicate relief valves, each having adequate capacity to protect the system. Arrange isolating valves or 3-way valve to assure at least one relief system is working at all times.

8.4.4 Capacity of Pressure Relieving and Pressure Limiting Station and Devices

8.4.4.1 Required Capacity of Pressure Relieving and Pressure Limiting Stations

Each pressure relief station or pressure limiting station shall have sufficient capacity and shall be set to operate to prevent the pressure from exceeding the following levels.

- (a) *Systems With Pipe or Pipeline Components Operating Over 72% of SMYS.* MAOP + 4%
- (b) *Systems With Pipe or Pipeline Components Operating at or Below 72% SMYS.* The lesser of:
 - 1. MAOP + 10%
 - 2. the pressure which produces a hoop stress of 75% SMYS.

8.4.5 Uprating

Minimum requirements for uprating pipelines to higher MAOP's are outlined in this section.

8.4.5.1 General

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- (a) A higher MAOP established in this section may not exceed the design pressure of the weakest element in the system to be uprated.
- (b) A plan shall be prepared for uprating which shall include a written procedure that will insure compliance with each applicable requirement of this section.
- (c) The following investigative and corrective measures shall be taken prior to increasing the MAOP of a pipeline that has been operating at a lower pressure;
 - 1. The design, initial installation, method, and date of previous testing, Location Classes, materials, and equipment shall be reviewed to determine that the proposed increase is safe and consistent with the requirements of ANSI B31.8.
 - 2. The condition of the pipeline shall be determined by leakage survey, other field inspections, and examination of maintenance records.
 - 3. Repairs, replacements, or alterations disclosed to be necessary by 1 and 2 shall be completed.
 - 4. A new test in accordance with the requirements of ANSI B31.8 should be considered if satisfactory evidence is not available to assure safe operation at the proposed higher MAOP.
 - 5. Records for uprating, including investigative steps, corrective action taken, and pressure test conducted, shall be retained as long as the pipeline remains in service.

8.4.5.2 Uprating Steel Pipelines to a Pressure That Will Produce a Hoop Stress of 30% or More of SMYS.

The MAOP may be increased after compliance with paragraphs c above and paragraph 845.61c, ANSI B31.8, and one of the following provisions:

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- (a) All three of the following requirements are satisfied:
 - 1. If the physical condition of the pipeline as determined above indicates the line is capable of withstanding the desired higher operating pressure;
 - 2. Is in general agreement with the design requirements in ANSI B31.8;
 - 3. And the line has been previously tested to a pressure equal to or higher than required by the Code for a new line at the proposed MAOP
- (b) If the pipeline does not meet the requirements in ANSI B31.8 for uprating, the line may be operated at the higher MAOP if the line shall successfully withstand the test required by ANSI B31.8 for a new line to operate at a higher MAOP.

8.5 VALVES

8.5.1 Required Spacing of Valves - Transmission Pipelines

8.5.1.1 Isolation valves shall be installed in new transmission pipelines during construction. Spacing between isolation valves on a new transmission line shall not exceed 4 miles in areas of predominately Location Class 3. Spacing may be adjusted slightly to permit valve installation in a more accessible location.

8.5.1.2 Spacing of sectionalizing (isolation) valves shall be determined by the following factors:

- (a) Continuous accessibility
- (b) Gas conservation
- (c) Blow-down time
- (d) Continuity of gas service
- (e) Operational flexibility
- (f) Future development
- (g) Safety and health

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(h) Security

8.5.2 Location of Valves

8.5.2.1 Isolation valves (sectionalizing block valves) shall be accessible and protected from damage and tampering.

8.5.2.2 Isolation valves may be installed above ground, in a vault, or buried. In all installations an operating device to open or close the valve shall be readily accessible to authorized persons. All valves shall be supported to prevent settlement or movement of the valve and attached piping.

8.5.2.3 Blowdown valves shall be provided to depressurize each section of pipelines between mainline valves. Size and capacity of blow-down lines shall permit line blowdown as quickly as possible in emergency conditions.

8.6 VAULTS**8.6.1 Structural Design Requirements**

Underground vaults or pits for valves, pressure-relieving, pressure-limiting, or pressure-regulating stations shall be designed and constructed in accordance with the provisions of section 847, ANSI B31.8 and include:

- (a) Vaults and pits shall be designed and constructed in accordance with good structural engineering practice to meet the loads which may be imposed on them.
- (b) Sufficient working space shall be provided to allow proper installation, operation, and maintenance for all equipment and piping systems in the vault.
- (c) Installed equipment (pressure-limiting/relieving/regulating) and piping shall be protected from unexpected loads such as explosion forces and roof/sides falling into the vault.
- (d) Pipe entering and within regulator vaults or pits shall be steel for NPS 10 and smaller sizes, except control and gauge piping may be copper. Piping extending through the vault walls or floor should be sealed to prevent

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passage of gas or liquid into or from the vault. Equipment and piping shall be supported by metal, masonry, or concrete supports. Control piping shall be run and supported to reduce mechanical damage to a minimum.

8.6.2 Accessibility

8.6.2.1 Important factors to consider for vault location are as follows:

- (a) *Exposure to Traffic* - Avoid street intersection and heavy traffic areas.
- (b) *Exposure to Flooding* - Do not locate at minimum elevation points, near catch basins, or in the path of surface water runoff.
- (c) *Exposure to Adjacent Subsurface Hazards* - Locate as far as practical from water, electric, steam, or other facilities.

8.6.3 Drainage and Waterproofing

- (a) Water entry into vaults should be minimized. However, submerged vault equipment shall be designed to operate safely.
- (b) No vault containing gas piping shall be connected by means of a drain connection to any other substructure, such as a sewer.
- (c) Electrical equipment in vaults shall conform to the requirements of Class 1, Group D, ANSI/NFPA 70.

9 OPERATING AND MAINTENANCE PROCEDURES**9.1 OPERATING AND MAINTENANCE PROCEDURES AFFECTING THE SAFETY OF GAS TRANSMISSION FACILITIES****9.1.1 Basic Requirements****9.1.2 Essential Features of the Operating and Maintenance Plan****9.1.3 Essential Features of the Emergency Plan****9.1.3.1 Written Emergency Procedures****9.1.3.2 Training Program****9.1.3.3 Liaison****9.1.3.4 Educational Program**

9.1.4 Pipeline Failure Investigation

9.1.4.1 Company has developed an Engineering Specification which covers the repair of pipeline failures. Included in the specification is the requirement for failure analysis and studies to minimize the reoccurrence of the problem.

9.1.5 Prevention of Accidental Ignition**9.1.6 Blasting Effects****9.2 PIPELINE MAINTENANCE****9.2.1 Continuing Surveillance of Pipelines**

9.2.1.1 Company shall continually survey its gas transmission pipelines to assure the integrity of its pipeline system. Studies shall be initiated and appropriate action taken where unusual operating and maintenance conditions occur, such as failures, leakage history, drop in flow efficiency due to internal corrosion, or substantial changes in cathodic protection requirements.

9.2.1.2 When such studies indicate the facility is in unsatisfactory condition, a planned program shall be initiated to abandon, replace, or recondition and proof test. If the pipeline cannot be reconditioned or phased out, the maximum allowable operating pressure (MAOP) shall be reduced in accordance with the requirements in this Company Specification and ANSI B31.8.

9.2.2 Pipeline Patrolling

9.2.2.1 Company shall maintain a periodic pipeline patrol program to observe surface conditions, on and adjacent to the pipeline right-of-way, leak indications, construction activities other than Company work, and any other factors affecting the safety and operation of the pipeline. Patrols shall be performed at least once each six (6) months as required for pipelines in Location Class 3. Weather, terrain, size of the line, operating pressures, and other conditions will be factors in determining the need for

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more frequent patrols. Main highways and railroad crossings shall be inspected with greater frequency and more closely than pipelines in open country.

9.2.2.2 Maintenance of Cover at Road Crossings and Drainage Ditches

Company shall perform periodic surveys to insure that adequate cover is maintained over the pipeline at road crossings and drainage ditches. If the cover has been reduced to unacceptable levels due to earth removal or line movement, Company shall provide additional protection with barriers, culverts, concrete pads, casing, lowering the line, or other suitable means.

9.2.2.3 Maintenance of Cover in Cross-Country Terrain

Company shall provide additional cover over cross-country pipelines by replacing cover, lowering the line, or other suitable means.

9.2.3 Leakage surveys

Company shall perform periodic leakage surveys for gas transmission pipelines in accordance with its operating and maintenance plan. The type of leak survey shall be effective for determining potentially hazardous leakage. The extent and frequency of the leak surveys shall be determined by the operating pressure, piping age, class location, and odorization of transported gas.

9.2.4 Repair Procedures for Steel Pipelines Operating at or Above 40% of the Specified Minimum Yield Strength

9.2.4.1 Appendix L, ANSI B31.8 shall be used to determine the need for repair on all Company gas transmission pipelines.

9.2.4.2 Temporary repairs shall be employed immediately, but permanent repairs shall be completed as soon as possible consistent with the requirements in the specification, ANSI B31.8, and 49CFR192. If the pipeline cannot be taken out of service during temporary repair work, the operating pressure shall be reduced to 20% or less of the SMYS during all welding operations for repair.

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9.2.4.3 Gouges and grooves are defined as injurious and in need of repair or replacement when the depth of the defect is more than 10% of the nominal wall thickness of the pipe.

9.2.4.4 Two (2) types of pipeline repair procedures are acceptable for repair of Company pipeline and are defined in Company Engineering Specification, "Repair Procedures for Gas Transmission Pipeline". These types include:

(a) Remove section of damaged pipe at least two pipe diameters in length. Replace section with equivalent pipe section with strength and thickness specifications carefully defined.

(b) Use a full-encirclement welded-split-sleeve with a design pressure equal to or greater than the MAOP of the pipeline.

9.2.4.5 Proprietary patch clamps (Plidco or equivalent) can be installed as a temporary repair.

9.2.4.6 Circular patches, pipe caps, weld bosses, and weld overlay repairs are approved for leak repair only on Company gas transmission pipelines.

9.2.5 Permanent Field Repairs of Injurious Gouges, Grooves, Dents, and Welds:

(a) Unacceptable gouges, grooves, dents, and welds shall be removed or reinforced, or a reduction in the maximum allowed operating pressure (MAOP) for the pipeline will be made in accordance with established derating specifications.

(b) All repairs shall pass nondestructive and/or pressure tests as required in ANSI B31.8 and API Standard 1104. ENGINEERING SERVICES, LP reserves the right to make repairs to ASME Standard B31.3 on DOT regulated pipelines. In each case, the particular circumstances of the project will determine which standard shall be used on DOT regulated Pipelines. For work to be performed inside ENGINEERING SERVICES, LP or Conoco Battery limits, the more stringent Standard of ASME B31.3 shall be used.

9.2.6 Permanent Field Repair of Leaks and Nonleaking Corroded Areas

[Complete repair details are provided in Company Pipeline Repair Procedures Engineering Specifications]

(a) Recommended method repair is removal of corroded section and replacement with pipe of equal or greater design strength.

(b) Repairs shall be made by the installation of a full-encirclement welded-split sleeve unless a patch or a weld overlay repair is made.

(c) Bolt-on leak clamps, welding bosses with nipple/valve installation, circular patches on low-strength pipe material (SMYS<40,000 psi), and weld overlay repairs may be used for leaks and localized pits.

(d) All repairs shall pass nondestructive and/or pressure tests as required in ANSI B31.8 and API Standard 1104. ENGINEERING SERVICES, LP reserves the right to make repairs to ASME Standard B31.3 on DOT regulated pipelines. In each case, the particular circumstances of the project will determine which standard shall be used on DOT regulated Pipelines.

9.2.7 Testing Repairs to Steel Pipelines or Mains Operating at Hoop Stress Levels at or Above 40% of the Specified Minimum Yield Strength:**9.2.7.1 Testing of Replacement Pipe Sections**

Replacement sections in pipeline repairs shall be subjected to a pressure test equivalent to the original design and construction. Tie-in welds are excluded from this requirement if 100% radiography is performed in lieu of hydrotest.

9.2.7.2 Nondestructive Testing of Repairs, Gouges, Grooves, Dents, and Welds

All welding repairs shall be examined by nondestructive and/or pressure tests.

9.2.8 Pipeline Leak Records

9.2.8.1 Records shall be made covering all leaks and repairs.

9.2.8.2 All pipeline breaks shall be reported in detail.

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9.2.8.3 Pipeline leak/break/repair records with leak surveys, line patrols, and other records relating to routine or unusual inspections shall be maintained by the Company as long as the section of the pipeline remains in service.

9.2.9 Pipeline Markers

- (a) Signs or markers shall be installed where the presence of a pipeline at a road, highway, railroad, and stream crossing must be carefully defined for public safety.
- (b) The surrounding right-of-way shall be maintained to permit marker to be easily read and are not obscured by foliage.
- (c) Signs or markers shall include the following entries:
 - 1. "Gas (or name of gas transported) Pipeline"
 - 2. ENGINEERING SERVICES, LP Company
 - 3. Company telephone number including area code

9.2.10 Abandoning of Transmission Facilities

- (a) Pipelines and related facilities to be abandoned shall be disconnected from all sources and supplies of gas.
- (b) Facilities to be abandoned in place shall be purged of gas with an inert gas or liquid material and the ends sealed.
- (c) Facilities may be purged with air if no hydrocarbons remain in the pipeline to be abandoned. Precautions must be taken to insure that a combustible mixture is not present after purging.

9.2.11 Repositioning a Pipeline in Service

The following factors shall be considered when repositioning a pipeline:

- (a) Deflection;
- (b) Diameter, wall thickness, and grade of pipe;
- (c) Pipeline pressure, type of girth welds, test and operating history, presence of defects, existing curvature, bends, valves, and fittings;
- (d) Terrain and soil conditions;
- (e) Personnel safety considerations;
- (f) Additional stresses caused by repositioning the pipeline.

9.3 MISCELLANEOUS FACILITIES MAINTENANCE**9.3.1 Compressor Station Maintenance****9.3.1.1 Compressors and Prime Movers**

Startup, operating, and shutdown procedures are an important part of the Company's overall Operating Plan and shall be followed.

9.3.1.2 Inspection and Testing of Relief Valves

All pressure relieving devices in compressor stations shall be inspected and periodically tested to determine the accuracy of their set pressure. All defective or inadequate equipment shall be repaired or replaced. All remote control shutdown devices shall be inspected and tested at least annually.

9.3.1.3 Repairs to Compressor Station Piping

All scheduled repairs to compressor station piping operating at hoop stress levels at or above 40% SMYS shall be completed in accordance with paragraph 851.3, ANSI B31.8 except welded patches are prohibited.

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Testing repairs shall be done in accordance with paragraph 851.4, ANSI B31.8.

9.3.1.4 Isolation of Equipment for Maintenance or Alterations

Company shall follow established procedures for isolation of units or sections of piping for maintenance, and for purging prior to returning units to service.

9.3.1.5 Storage of Combustible Materials

Company shall follow guidelines in ANSI/NFPA30 for protection of aboveground or gasoline storage tanks.

9.3.2 Maintenance of Pressure Limiting and Pressure Regulating Stations

9.3.2.1 All pressure-limiting stations, relief devices, and other pressure-regulating stations and equipment shall periodically tested and inspected to determine:

- (a) Mechanical condition
- (b) Capacity, service reliability, and set pressure

9.3.2.2 Operational upsets may require pressure or flow control devices to be inspected and/or repaired.

9.3.2.3 Stop valves shall be periodically inspected and tested to insure operability and correct positioning. The following equipment will be included in the inspection and testing:

- 1. Station inlet, outlet, and bypass valves
- 2. Relief device isolating valves
- 3. Control, sensing, and supply line valves

Final inspection and testing will include:

- 1. A check for proper position of all valves.
- 2. Restoration of all locking and security devices to proper position.

9.3.3 Valve Maintenance

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9.3.3.1 Pipeline valves required to be operated during an emergency shall be periodically inspected and partially operated at least once a year to provide safe and proper operating conditions.

9.3.3.2 Routine valve maintenance procedures shall include, but not be limited to, the following:

1. Servicing in accordance with written procedures by adequately trained personnel;
2. Accurate system maps for use during routine or emergency conditions;
3. Valve security to prevent service interruptions, tampering, etc., as required;
4. Employee training programs to familiarize personnel with the correct valve maintenance procedures.

9.3.3.3 Emergency valve maintenance procedures include:

1. Written contingency plans to be followed during any type emergency;
2. Training personnel to anticipate all potential hazards;
3. Furnishing tools and equipment as required, including auxiliary breathing equipment, to meet anticipated emergency valve servicing and/or maintenance requirements.

9.3.3.4 Valve Records

Valve records shall be maintained on operating maps, separate files, or summary sheets, and the information shall be readily accessible to personnel required to respond to emergencies.

9.3.3.5 Prevention of Accidental Operation

Company shall develop procedures to prevent accidental operation of pipeline valves. Recommended actions are:

- (a) Lock valves in aboveground settings that are readily accessible to the general public and are not enclosed by a building or fence.
- (b) Lock valves in vaults, if accessible to the general public.
- (c) Identify the valve by tagging, color coding, or other means of identification.

9.3.4 Vault Maintenance

Each vault housing a pressure-limiting, pressure-relief, or pressure-regulating stations shall be inspected when the equipment is inspected and/or tested. Inspection shall include:

1. Testing for combustible gas mixtures;
2. Adequate ventilation;
3. Safety protection for personnel.

9.4 LOCATION CLASS AND CHANGES IN NUMBER OF BUILDING INTENDED FOR HUMAN OCCUPANCY

Company shall maintain continuing surveillance of existing steel pipelines operating in excess of 40% SMYS to determine if additional buildings intended for human occupancy have been constructed. The total number of buildings intended for human occupancy shall be counted to determine the current Location Class. Company shall follow the guidelines in Section 854, ANSI B31.8.

9.5 PIPELINE SERVICE CONVERSIONS

9.5.1 General

This section summarizes requirements to allow the Company to operate a pipeline previously used for service not covered by ANSI B31.8 to qualify the pipeline for service as a gas transmission pipeline under B31.8.

9.5.2 Historical Records Study

Review the following historical data and make an evaluation of the pipeline's condition.

- (a) Study all available information on the original pipeline design, inspection, and testing.
- (b) Study available operating and maintenance data including leak records, inspections failures, cathodic protection, and internal corrosion control practices.
- (c) The age of the pipeline and the length of time not in use.

9.5.3 Requirements for Conversion to Gas Service

A steel pipeline previously used for service not subject to ANSI B31.8 may be qualified to this Code as follows:

- (a) Review historical records of the pipeline.
- (b) Inspect all above ground segments of the pipeline for physical condition. Identify pipeline material to compare with available records.
- (c) *Operating Stress Level Study*
 - 1. Establish the number of buildings intended for human occupancy and determine the design factor for each segment.
 - 2. Conduct a study to compare the proposed operating stress levels with those allowed for the Location Class.

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3. Make the necessary replacements to insure that the operating stress level is consistent with the Location Class.
- (d) Complete inspections on appropriate sections of underground piping to determine the condition of the pipeline, if necessary.
- (e) Schedule replacements, repairs, or alterations recommended by the Company.
- (f) Perform a strength test in accordance with ANSI B31.8 to establish the MAOP of the pipeline.
- (g) Perform a leak test in accordance with ANSI B31.8.
- (h) Provide cathodic protection for the pipeline within one year of the conversion. Replacement sections and other new piping shall be cathodically protected as required for new construction.

9.5.4 Conversion Procedure

Company shall prepare a written procedure outlining the steps to be followed during the study and conversion of the pipeline system. Note any unusual conditions relating to this conversion.

9.5.5 Records of the Conversion

Company shall maintain for the life of the pipeline a record of the studies, inspections, tests, repairs, replacements, and alterations made in connection with conversion of the existing steel pipeline to gas service under the requirements in ANSI B31.8.

10 CORROSION CONTROL**10.1 SCOPE**

- 10.1.1** Minimum requirements and procedures for corrosion control of above-ground, buried, and submerged DOT-regulated pipelines are summarized in the Lake Charles Chemical Complex Engineering Specification, "Corrosion Control and Monitoring". Chapter VI, "Corrosion Control", ANSI/ASME B31.8 also

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constraints requirements applicable to the design and installation of new piping systems and to the operation and maintenance of existing pipeline systems.

10.1.2 Provisions for the corrosion control of DOT-regulated gas transmission pipelines shall be administered under the direction of competent corrosion control personnel. Minimum qualifications for supervisory work include NACE accreditation as a Corrosion Specialist with 10 years experience in all phases of corrosion control in gas transmission pipeline systems.

10.1.3 Procedures including the design, installations, and maintenance of cathodic protection systems of cathodic protection systems, casing design and specifications, and pipeline repair/maintenance are included as part of the Lake Charles Chemical Complex Operating Procedures and shall be referred to in all pipeline activities.

10.2 EXTERNAL CORROSION CONTROL

10.2.1 New Installations

10.2.1.1 Buried Steel Facilities

10.2.1.1.1 General

New gas transmission pipelines shall be externally coated and cathodically protected.

10.2.1.1.2 Coating Requirements

Coating systems shall be one of the following types:

- (a) Fusion bonded epoxy [FBE]
- (b) Coal tar epoxy
- (c) Polyethylene tape
- (d) Shrink wrap sleeves and tape

10.2.1.1.3 Cathodic Protection Requirements

- (a) Buried onshore gas transmission pipelines shall have a pipe-to-soil potential equal to or more negative than 0.85 volts with reference to copper/copper

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sulfate reference half cell. For impressed current systems, the potential shall be recorded immediately after interruption of the current supply [“Instant-off potential”].

- (b) Underwater pipelines shall have a pipe-to-soil potential equal to or more negative than 0.80 volts with reference to a silver/silver chloride half cell.
- (c) Maximum “instant-off” potential for buried gas transmission pipelines shall not be more negative than 1.1 volts.

10.2.1.1.4 Electrical Isolation

- (a) Company gas transmission pipelines shall cross other non-Company pipelines as close to perpendicular as possible. Company pipelines will be protected and monitored at all crossings by a resistance-controlled bonding station.
- (b) Where a gas pipeline parallels overhead electric transmission pipelines, consideration shall be given to:
 - 1. The necessity of protecting insulating joints and pipeline coating against induced voltages from ground faults and lightning.
 - 2. The need to mitigate AC voltages or their effects on personnel safety during construction and operation by bonding shielding, or grounding techniques.
 - 3. Adverse effects on cathodic protection.

10.2.1.1.5 Electrical Connections and Monitoring Points

- (a) Company Engineering Specification, “Corrosion Control and Monitoring” describes bonding and test stations which shall be installed to assure adequate pipeline monitoring sites.

10.2.1.1.6 Electrical Interference

- (a) Impressed current cathodic protection systems shall be designed, installed, and operated to minimize adverse effects on existing structures.
- (b) Field tests shall be conducted to determine electrical interference from foreign structures, including DC electrical facilities.

10.2.1.1.7 Casings

Company engineering specifications and ANSI B31.8 shall be used for the design, construction, and operation of pipeline casings. An engineer with the qualifications in Scope above will be employed for these tasks.

10.2.1.2 Atmospheric Protection

10.2.1.2.1 Pipelines and equipment exposed to atmosphere shall be protected from atmospheric corrosion when required by the Company corrosion engineer.

10.2.1.2.2 Coatings shall be selected and applied in accordance with established specifications and/or manufacturer’s recommendations.

10.2.2 Existing Installation**10.2.2.1 Buried Steel Pipelines****10.2.2.1.1 Evaluation**

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- (a) Leak surveys and normal maintenance records shall be continually reviewed for evidence of corrosion.
- (b) Pipe-to-soil potential surveys shall be completed on Company pipelines in accordance with the Corrosion Control and Monitoring Engineering Specification.
- (c) Close-interval cathodic-protection potential surveys shall be completed when recommended by the Company corrosion engineer.

10.2.2.1.2 Corrective Measures

Appropriate corrective measures shall be taken to minimize corrosion attack on existing pipelines and may consist of one or more of the following techniques:

- (a) Provisions for proper and continuous operation of cathodic protection facilities;
- (b) Application or rehabilitation of protective coating;
- (c) Installation of galvanic anodes;
- (d) Application of impressed current or increased current levels for existing installations;
- (e) Electrical isolation (bonding stations);
- (f) Stray current control;
- (g) Other effective corrosion control measures.

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10.2.2.1.3 Repair of Corroded Pipe

The remaining strength of corroded pipe may be determined in accordance with Appendix L, ANSI B31.8 with supporting development information in ANSI/ASME B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines".

10.2.2.1.4 Cathodic Protection Criteria

Company gas transmission pipelines are considered to be cathodically protected when the pipe-to-soil potential is equal to or more negative than -0.85 volts referenced to a copper/copper sulfate electrode. Alternative criteria are summarized in Appendix K, ANSI B31.8.

10.2.2.1.5 Electrical Interference

Bonding stations to minimize electrical interference shall be monitored on a periodic basis in accordance with Company specifications.

10.2.2.1.6 Examination When Exposed

A visual examination shall be made when a buried pipeline is exposed. Inspection shall be completed on coating condition and/or the pipe surface. The extent of corrosion and the need for repair shall be evaluated in accordance with Appendix L, ANSI B31.8 and Company Specifications.

10.2.2.1.7 Operation and Maintenance of Cathodic Protection System

- (a) Potential surveys shall be completed on an annual basis for all Company gas transmission pipelines.
- (b) Rectifier readings will be recorded monthly with any deviations from accepted criteria reported to Engineering.
- (c) Bonding and test stations will be monitored with a maximum interval of one year.

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10.2.2.1.8 Casings

Casing-to-soil and pipe-to-soil potential surveys shall be completed on an annual basis with any deviation reported to Engineering for evaluation and repair, if necessary. The potential surveys shall be completed at the same time as the annual potential survey for pipelines.

10.2.2.2 Atmospheric Corrosion

All pipelines and equipment which covered by this Company specification and is exposed to the atmosphere will be inspected on an annual basis for indication of surface corrosion. The guidelines in Appendix L, Remaining Strength of Corroded Pipelines shall be used to determine the requirement for repair/replacement or coating application.

10.3 INTERNAL CORROSION CONTROL**10.3.1 General**

Pipelines shall be evaluated whenever a process changes that may cause the piping systems to be corroded internally. Gas containing free water shall be assumed to be corrosive, unless proven otherwise by tests or experience. Gas at temperatures continually above the dewpoint under all operating conditions shall be classified as noncorrosive.

10.3.2 New Installations

New/or replacement pipeline systems or additions/modifications to existing systems shall be designed to prevent or inhibit internal corrosion, or both.

The following factors should be included in the design and construction of gas transmission pipelines where a corrosive gas will be transported:

10.3.2.1 Corrosion monitoring installations will be included and will have the capability of insertion and retrieval under operating pressures.

10.3.2.2 Cost-effective evaluations will be completed for the different programs available to control corrosion in gas pipelines. These options include:

- (a) Corrosion inhibitor injection

- (b) Internal coating application before construction
- (c) Pigging operations to clean internal surfaces during operation
- (d) Process changes to remove corrosents
- (e) Any combination of the above mitigation techniques

10.3.2.3 Corrosion inhibitor requirements:

- (a) The equipment for holding, transfer, and injection of inhibitor shall be included in the design;
- (b) The operation of the corrosion-inhibitor injection program will be part of operation planning and implementation;
- (c) Coupon holder or other monitoring equipment shall be recommended by the Company corrosion engineer to provide for continuous program evaluation;
- (d) The selected corrosion inhibitor shall not cause deterioration of any piping system component and shall not degrade under process/pipeline conditions to cause operating problems;

10.3.2.4 Internal coating requirements:

- (a) The coating shall meet the quality specifications and minimum dry film thickness recommended by the coating manufacturer;
- (b) Shop-applied coatings shall be inspected in accordance with established specifications or accepted practice;
- (c) When coated pipe is joined by field welding, provision shall be made to prevent joint corrosion including;
 - (1) Cleaning and recoating of the weld damage area; or

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(2) Continuous injection of a suitable corrosion inhibitor;

- (d) If pigs or spheres are planned during operations, cleaning components on the pigs should be selected to minimize coating damage;

10.3.2.5 Pipeline pigging specifications:

- (a) Scraper traps for the insertion and removal of pigs, spheres, or both shall be provided. Length of trap must accommodate the operation of instrumented pigs in the pipeline.
- (b) Sections of pipeline to be pigged shall contain bends or elbows with a radius equal to 5D or more in order to accommodate instrumented pigging operations;
- (c) Piping for pigging operations shall be designed in accordance with the requirements of ANSI B31.8;
- (d) Provision shall be made for the effective accumulation and handling of liquid and solid materials removed from the pipeline by pigs or spheres.

10.3.2.6 Corrosion monitoring equipment specifications:

- (a) Corrosion coupons, electrical-resistance probes, or hydrogen probes shall be installed in the pipelines where the greatest potential for corrosion exists;
- (b) Corrosion monitoring equipment must be designed to permit passage of pigs or spheres, if necessary;

10.3.2.7 Gas process change methods to remove corrodents:

- (a) Separators or dehydration equipment, or both, may be installed;
- (b) Equipment for the removal of other corrodents or deleterious material.

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10.3.2.8 The material of the pipe and other equipment exposed to the gas stream must resist internal corrosion. The following material specifications must be considered:

- (a) Material selection for pipe and fittings shall be consistent with the components of the gas, the liquids carried by the gas, and with each other. A source of information on materials performance in corrosive environments is the *Corrosion Data Survey* published by the National Association of Corrosion Engineers (NACE).
- (b) Erosion-corrosion effects caused by turbulence and impingement should be minimized by use of erosion resistant materials, added wall, design or flow configuration, and size or dimensions of the pipe and fittings.

10.3.3 Existing Installations

A pipeline internal corrosion control program shall include, but not be limited to, the following guidelines in ANSI B31.8, paragraph 863.3:

10.3.3.1 The establishment and evaluation of a program for the detection, prevention, or mitigation of detrimental corrosion should include the following:

- (a) Pipeline leak and repair records should be reviewed for indication of the effects of internal corrosion.
- (b) Internal parts of the pipeline which become accessible for inspection shall be visually inspected for internal corrosion.
- (c) Active corrodents shall be determined when evidence of internal corrosion is suggested.
- (d) Liquids or solids removed from the pipeline by pigging, draining, or cleaning should be analyzed to determine the presence of corrodents and evidence of corrosion products.

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10.3.3.2 When it is determined that internal corrosion is occurring that could affect public or employee safety, one or more of the following protective corrective measures shall be used to control detrimental internal corrosion.

- (a) Corrosion inhibitor injection to protect all affected portions of the systems.
- (b) Remove corrosive agents by recognized methods, such as acid gas or dehydration treating plants.
- (c) Remove water from low spots and reposition piping to eliminate “dead areas” (stagnant process fluids).
- (d) Internal coating application.

10.3.3.3 Internal corrosion control programs shall be evaluated by an inspection and monitoring program including, but not limited to, the following actions:

- (a) Corrosion inhibitor and inhibitor injection equipment should be checked daily as a part of normal operational checks.
- (b) Corrosion coupons and test spools shall be removed and evaluated at periodic intervals.
- (c) Electrical-resistance and hydrogen probe readings should be checked manually at intervals not to exceed weekly or continuously/intermittently monitored or recorded, or both, to evaluate control of pipeline internal corrosion.
- (d) A record of the internal condition of the pipe, leaks and repairs from corrosion, gas, liquids, or solids quantities and corrosivity should be used as a basis for changes in pigging schedule, inhibitor program, or gas treatment facility.
- (e) Ultrasonic measurements on pipe wall for above ground or excavated piping will provide additional data for internal corrosion monitoring without visual inspection.

- (f) Immediate action to repair or recondition sections of pipeline shall be implemented where internal corrosion is indicated and may be detrimental to public or employee safety.

10.4 PIPELINES IN HIGH TEMPERATURE SERVICE

10.4.1 General

Elevated temperatures decrease the resistivity of buried pipeline environments and to increase the electrochemical corrosion reaction as a result of accelerated ionic or molecular activity. Elevated temperatures typically occur downstream of compressor stations.

10.4.2 External Coating Requirements

External coatings for pipelines in high-temperature service shall be selected to minimize coating degradation at operating temperatures.

10.4.3 Cathodic Protection Facilities

Acceptance criteria for high-temperature pipelines shall be the same as normal temperature, i.e., more negative than -0.85 volts with reference to a copper/copper sulfate electrode measured immediately after current interruption. Consideration must also be given to the following effects of cathodic protection systems from high-temperature environments:

- (a) Decreased resistivity and increased cathodic protection current requirements in elevated temperature service on any IR (voltage) component of the pipe-to-soil potential measurements.
- (b) Depolarization effects due to high temperature operation shall also be considered.
- (c) High temperatures increase the current output and rate of degradation of galvanic anodes. Zinc anodes may become more noble than steel at temperatures above 140°F in select electrolytes. Zinc anodes containing aluminum are also susceptible to intergranular corrosion above 120°F.

10.4.4 Internal Corrosion Control

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Corrosion reaction rates increase with increased temperatures. Special consideration shall be given to the identification and mitigation of internal corrosion at higher temperatures.

10.5 STRESS CORROSION AND OTHER PHENOMENA

Environmentally induced and other corrosion-related phenomena, including stress corrosion cracking, corrosion fatigue, hydrogen stress-cracking, and hydrogen embrittlement have been identified as causes of pipeline failure. Company should be alert for evidence of these corrosion problems during all pipe inspections. Where evidence of one or more of these phenomena is found, an investigative program shall be initiated and appropriate remedial measures taken as necessary.

10.6 RECORDS

10.6.1 Records showing cathodically protected pipelines, cathodic protection equipment and installations, and other structures affected by or affecting the cathodic protection system shall be maintained by the Company.

10.6.2 Records of tests, surveys, inspection results, leaks, etc., necessary for evaluating the effectiveness of corrosion control measures, shall be maintained as long as the pipeline remains in gas transmission service.