AN AMERICAN NATIONAL STANDARD

ASME B31.8a-2000

ADDENDA

to

ASME B31.8-1999
GAS TRANSMISSION
AND
DISTRIBUTION
PIPING SYSTEMS

THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS
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ASME B31.8a-2000

Following approval by the ASME B31 Committee and ASME, and after public review, ASME B31.8a-2000 was approved by the American National Standards Institute on December 13, 2000.

This is the first Addenda to be published to ASME B31.8-1999. It was issued on November 16, 2001, and is effective upon date of issuance.

Addenda to the 1999 Edition of ASME B31.8 are issued in the form of replacement pages. Revisions, additions, and deletions are incorporated directly into the affected pages. It is advisable, however, that this page, the Addenda title and copyright pages, and all replaced pages be retained for reference.

SUMMARY OF CHANGES

Replace or insert the pages listed. Changes given below are identified on the pages by a margin note, **A00**, placed next to the affected area. Changes made in ASME B31.8-1999 are indicated by **(99)**. The pages not listed are the reverse sides of the listed pages and contain no changes.

Page	*Location*	*Change*
iii–v	Contents	Updated to reflect Addenda
7	805.217	Revised
8	807	Added
10	811.25	Revised
11	817.11	Revised
23	831.373	First and second paragraphs revised
31	841.11(c)(1)	Revised
36	841.231(g)	Revised
70, 70.1	850.43(a)	Revised and redesignated from 850.43
	850.43(b)	Added
	850.43(c)	Added
	850.44	Revised
74, 74.1	851.9	Added
	851.10	Added
	851.11	Redesignated from 851.9
76, 76.1	852.52	Second paragraph added
95, 95.1	A802.3	Added
96, 96.1	A803	Definition of *return interval* revised

Page	*Location*	*Change*
	A811	Revised
	A814.1	Last paragraph added
97, 97.1	A817	Added
	A817.1	Added
	A817.2	Added
	A817.3	Added
101, 101.1	Table A842.22	Note (1) added
115	B850.1(c)(2)(b)	Equation corrected by errata to read 0.4546
183, 184	Index	Updated to reflect Addenda

SPECIAL NOTE

The interpretations to ASME B31.8 are included as a separate section for the user's convenience.

CONTENTS

Appendices

805.12 For definitions of *leakage investigation terms,* see Appendix M.

805.13 Plastic Terms

805.131 Plastic Joint Nomenclature

(a) Solvent cement joint is a joint made in thermoplastic piping by the use of a solvent or solvent cement that forms a continuous bond between the mating surfaces.

(b) Heat fusion joint is a joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when the parts are pressed together.

(c) Adhesive joint is a joint made in plastic piping by the use of an adhesive substance that forms a continuous bond between the mating surfaces without dissolving either one of them.

805.132 *Standard dimension ratio* is the ratio of outside pipe diameter to wall thickness of thermoplastic pipe. It is calculated by dividing the specified outside diameter of the pipe by the specified wall thickness in inches.

805.133 *Long-term hydrostatic strength* is the estimated hoop stress in pounds per square inch in a plastic pipe wall that will cause failure of the pipe at an average of 100,000 hr when subjected to a constant hydrostatic pressure. (See Appendix D.)

805.14 Fabrication

805.141 *Cold-springing,* where used in the Code, is the fabrication of piping to an actual length shorter than its nominal length and forcing it into position so that it is stressed in the erected condition, thus compensating partially for the effects produced by the expansion due to an increase in temperature. Cold-spring factor is the ratio of the amount of cold spring provided to the total computed temperature expansion.

805.15 *Uprating* is the qualifying of an existing pipeline or main for a higher maximum allowable operating pressure.

805.2 Design

805.21 Pressure Terms

805.211 *Pressure,* unless otherwise stated, is expressed in pounds per square inch above atmospheric pressure (i.e., gage pressure) and is abbreviated as psig.

805.212 *Design pressure* is the maximum pressure permitted by this Code, as determined by the design procedures applicable to the materials and locations involved.

805.213 *Maximum operating pressure (MOP),* sometimes referred to as maximum actual operating pressure, is the highest pressure at which a piping system is operated during a normal operating cycle.

805.214 *Maximum allowable operating pressure (MAOP)* is the maximum pressure at which a gas system may be operated in accordance with the provisions of this Code.

805.215 *Maximum allowable test pressure* is the maximum internal fluid pressure permitted by this Code for a pressure test based upon the material and location involved.

805.216 *Standard service pressure,* sometimes called the normal utilization pressure, is the gas pressure a utility undertakes to maintain at its domestic customers' meters.

805.217 *Overpressure protection* is provided by a device or equipment installed in a gas piping system that prevents the pressure in the system or part of the system from exceeding a predetermined value. **A00**

805.218 *Standup pressure test* demonstrates that a pipe or piping system does not leak, as evidenced by the lack of a drop in pressure over a specified period of time after the source of pressure has been isolated.

805.22 Temperature Terms

805.221 *Temperature* is expressed in degrees Fahrenheit (°F) unless otherwise stated.

805.222 *Ambient temperature* is the temperature of the surrounding medium, usually used to refer to the temperature of the air in which a structure is situated or a device operates.

805.223 *Ground temperature* is the temperature of the earth at pipe depth.

805.23 Stress Terms

805.231 *Stress,* expressed in pounds per square inch, is the resultant internal force that resists change in the size or shape of a body acted on by external forces. In this Code, "stress" is often used synonymously with unit stress, which is the stress per unit area.

805.232 *Operating stress* is the stress in a pipe or structural member under normal operating conditions.

805.233 *Hoop stress,* S_H, is the stress in a pipe of wall thickness, t, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe, produced by the pressure, P, of the fluid in a pipe of diameter, D, and is determined by Barlow's formula:

$$S_H = \frac{PD}{2t}$$

805.234 *Maximum allowable hoop stress* is the maximum hoop stress permitted by this Code for the design of a piping system. It depends on the material used, the location of the pipe, the operating conditions, and other limitations imposed by the designer in conformance with this Code.

805.235 *Secondary stress* is stress created in the pipe wall by loads other than internal fluid pressure, such as backfill loads, traffic loads, loads caused by natural hazards (see para. 841.13), beam action in a span, loads at supports, and at connections to the pipe.

807 QUALITY ASSURANCE A00

Quality Control systems consist of those planned, systematic, and preventative actions that are required to ensure that materials, products, and services will meet specified requirements. Quality Assurance systems and procedures consist of periodic audits and checks that ensure the Quality Control system will meet all of its stated purposes.

The integrity of a pipeline system may be improved by the application of Quality Assurance systems. These systems should be applied to the design, procurement, construction, testing, operating, and maintenance activities in the applications of this Code.

Organizations performing design, fabrication, assembly, erection, inspection, examination, testing, installation, operation, and maintenance application for B31.8 piping systems should have a written Quality Assurance system in accordance with applicable documents. Registration or certification of the Quality Assurance system should be by agreement between the contracting parties involved.

CHAPTER I
MATERIALS AND EQUIPMENT

810 MATERIALS AND EQUIPMENT

810.1

It is intended that all materials and equipment that will become a permanent part of any piping system constructed under this Code shall be suitable and safe for the conditions under which they are used. All such materials and equipment shall be qualified for the conditions of their use by compliance with certain specifications, standards, and special requirements of this Code, or otherwise as provided herein.

811 QUALIFICATION OF MATERIALS AND EQUIPMENT

811.1

Materials and equipment fall into the following six categories pertaining to methods of qualification for use under this Code:

(a) items that conform to standards or specifications referenced in this Code

(b) items that are important from a safety standpoint, of a type for which standards or specifications are referenced in this Code but specifically do not conform to a referenced standard, e.g., pipe manufactured to a specification not referenced in the Code

(c) items of a type for which standards or specifications are referenced in this Code, but that do not conform to the standards and are relatively unimportant from a safety standpoint because of their small size or because of the conditions under which they are to be used

(d) items of a type for which no standard or specification is referenced in this Code, e.g., gas compressor

(e) proprietary items (see definition, para. 804.14)

(f) unidentified or used pipe

811.2

Prescribed procedures for qualifying each of these six categories are given in the following paragraphs.

811.21 Items that conform to standards or specifications referenced in this Code [para. 811.1(a)] may be used for appropriate applications, as prescribed and limited by this Code without further qualification. (See para. 814.)

811.22 Important items of a type for which standards or specifications are referenced in this Code, such as pipe, valves, and flanges, but that do not conform to standards or specifications referenced in this Code [para. 811.1(b)] shall be qualified as described in para. 811.221 or 811.222.

811.221 A material conforming to a written specification that does not vary substantially from a referenced standard or specification and that meets the minimum requirements of this Code with respect to quality of materials and workmanship may be used. This paragraph shall not be construed to permit deviations that would tend to affect weldability or ductility adversely. If the deviations tend to reduce strength, full allowance for the reduction shall be provided for in the design.

811.222 When petitioning the Section Committee for approval, the following requirements shall be met. **(99)**
If possible, the material shall be identified with a comparable material, and it should be stated that the material will comply with that specification, except as noted. Complete information as to chemical composition and physical properties shall be supplied to the Section Committee, and their approval shall be obtained before this material is used.

811.23 Relatively unimportant items that do not conform to a standard or specification [para. 811.1(c)] may be used, provided that

(a) they are tested or investigated and found suitable for the proposed service

(b) they are used at unit stresses not greater than 50% of those allowed by this Code for comparable materials

(c) their use is not specifically prohibited by the Code

(99) **811.24** Items of a type for which no standards or specifications are referenced in this Code [para. 811.1(d)] and proprietary items [para. 811.1(e)] may be qualified by the user provided

(a) the user conducts investigation and tests (if needed) that demonstrate that the item of material or equipment is suitable and safe for the proposed service

(b) the manufacturer affirms the safety of the item recommended for that service (e.g., gas compressors and pressure relief devices).

A00 **811.25** Unidentified or used pipe [para. 811.1(f)] may be used, and is subject to the requirements of para. 817.

812 MATERIALS FOR USE IN COLD CLIMATES

Some of the materials conforming to specifications referenced for use under this Code may not have properties suitable for the lower portion of the temperature band covered by this Code. Engineers are cautioned to give attention to the low-temperature impact properties of the materials used for facilities to be exposed to unusually low ground temperatures or low atmospheric temperatures.

813 MARKING

813.1

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

813.2

Die stamping, if used, shall be done with dies having blunt or rounded edges to minimize stress concentrations.

814 MATERIAL SPECIFICATIONS

For a listing of all referenced material specifications, see Appendix A. For a listing of standards for other commonly used materials that are not referenced, see Appendix C.

814.1 General Requirements

Pipe that is qualified under para. 811.1(a) may be used.

814.11 Steel Pipe

(a) Steel pipe manufactured in accordance with the following standards may be used:

API 5L	Line Pipe
ASTM A 53	Welded and Seamless Pipe
ASTM A 106	Seamless Pipe
ASTM A 134	Electric-Fusion (Arc)-Welded Pipe
ASTM A 135	Electric-Resistance-Welded Pipe
ASTM A 139	Electric-Fusion (Arc)-Welded Pipe
ASTM A 333	Seamless and Welded Pipe for Low-Temperature Service
ASTM A 381	Metal-Arc-Welded Pipe
ASTM A 671	Electric-Fusion-Welded Pipe
ASTM A 672	Electric-Fusion-Welded Pipe

(b) Cold expanded pipe shall meet the mandatory requirements of API 5L.

814.12 Ductile Iron Pipe. Ductile iron pipe manufactured in accordance with ANSI A21.52, titled Ductile-Iron Pipe, Centrifugally Cast, in Metal Molds or Sand-Lined Molds for Gas, may be used.

814.13 Plastic Pipe and Components

(a) Plastic pipe and components manufactured in accordance with the following standards may be used:

ASTM D 2513	Thermoplastic Gas Pressure Pipe, Tubing, and Fittings
ASTM D 2517	Reinforced Epoxy Resin Gas Pressure Pipe and Fittings

(b) Thermoplastic pipe, tubing, fittings, and cements conforming to ASTM D 2513 shall be produced in accordance with the in-plant quality control program recommended in Appendix A4 of that specification.

814.14 Qualification of Plastic Piping Materials

(a) In addition to complying with the provisions of (99)
para. 814.13, the user shall thoroughly investigate the specific plastic pipe, tubing, or fitting to be used and shall determine material serviceability for the conditions anticipated. The selected material shall be adequately resistant to the liquids and chemical atmospheres that may be encountered.

(b) When plastic pipe, tubing, or fittings of different material specifications are joined, a thorough investigation shall be made to determine that the materials are compatible with each other. See para. 842.39 for joining requirements.

814.2 Steel, Cast Iron, and Ductile Iron Piping Components

Specific requirements for these piping components that qualify under para. 811.1(a) are found in Chapter III.

815 EQUIPMENT SPECIFICATIONS

Except for the piping components and structural materials listed in Appendices A and C, it is not intended to include in this Code complete specifications for equipment. Certain details of design and fabrication, however, necessarily refer to equipment, such as pipe hangers, vibration dampeners, electrical facilities, engines, compressors, etc. Partial specifications for such equipment items are given herein, particularly if they affect the safety of the piping system in which they are to be installed. In other cases where the Code gives no specifications for the particular equipment item, the intent is that the safety provisions of the Code shall govern, insofar as they are applicable. In any case, the safety of equipment installed in a piping system shall be equivalent to that of other parts of the same system.

816 TRANSPORTATION OF LINE PIPE

Any pipe having an outer-diameter-to-wall thickness ratio of 70 to 1 or more, that is to be used in a pipeline at a hoop stress of 20% or more of the specified minimum yield strength that has been or will be transported by railroad, inland waterway, or by marine transportation, must have been or shall be loaded in accordance with API RP5L1 or API RP5LW, respectively. Where it is not possible to establish that pipe was transported in accordance with the appropriate recommended practice, the pipe must be hydrostatically tested for at least 2 hr to at least 1.25 times the maximum allowable operating pressure if installed in a Class 1 location, or to at least 1.5 times the maximum allowable operating pressure if installed in a Class 2, 3, or 4 location.

817 CONDITIONS FOR THE REUSE OF PIPE

817.1 Reuse of Steel Pipe

A00 **817.11** Removal of a portion of an existing steel line and reuse of the pipe in the same line or in a line operating at the same or lower pressure is permitted, and is subject to the restrictions of paras. 817.13(a), (f), and (i).

817.12 Used steel pipe and unidentified new steel pipe may be used for low-stress (hoop stress less than 6,000 psi) level service where no close coiling or close bending is to be done, provided that (99)

(a) careful visual examination indicates that it is in good condition and free from split seams or other defects that would cause leakage

(b) if the pipe is to be welded and is of unknown specification, it shall satisfactorily pass weldability tests prescribed in para. 817.13(e)

817.13 Used steel pipe and unidentified new steel pipe may be qualified for use at stress levels above 6,000 psi or for service involving close coiling or close bending by the procedures and within the limits outlined in the table below.

	New or Used Pipe, Unknown Specification	Used Pipe, Known Specification
Inspection	(a)	(a)
Bending properties	(b)	. . .
Thickness	(c)	(c)
Longitudinal joint factor	(d)	(d)
Weldability	(e)	. . .
Surface defects	(f)	(f)
Yield strength	(g)	. . .
S value (para. 841.11)	(h)	. . .
Hydrostatic test	(i)	(i)

GENERAL NOTE: The letters in the table correspond to the following subparagraphs, except where noted otherwise.

(a) Inspection. All pipe shall be cleaned inside and outside, if necessary, to permit good inspection. All pipe shall be visually inspected to determine that it is reasonably round and straight and to discover any defects that might impair its strength or tightness.

(b) Bending Properties. For pipe NPS 2 and smaller, a sufficient length of pipe shall be bent cold through 90 deg around a cylindrical mandrel, the diameter of which is 12 times the nominal diameter of the pipe, without developing cracks at any portion and without opening the weld.

For pipe larger than NPS 2, flattening tests as prescribed in Appendix H shall be made. The pipe shall meet the requirements in this test, except that the number of tests required to determine flattening properties shall be the same as required in subpara. (g) below to determine yield strength.

(c) Determination of Wall Thickness. Unless the nominal wall thickness is known with certainty, it shall

be determined by measuring the thickness at quarter points on one end of each piece of pipe. If the lot of pipe is known to be of uniform grade, size, and nominal thickness, measurement shall be made on not less than 10% of the individual lengths, but not less than 10 lengths; thickness of the other lengths may be verified by applying a gage set to the minimum thickness. Following such measurement, the nominal wall thickness shall be taken as the next commercial wall thickness below the average of all the measurements taken, but in no case greater than 1.14 times the least measured thickness for all pipe smaller than NPS 20, and no greater than 1.11 times the least measured thickness for all pipe NPS 20 and larger.

(d) Longitudinal Joint Factor. If the type of longitudinal joint can be determined with certainty, the corresponding longitudinal joint factor, *E* (Table 841.115A in Chapter IV), may be used. Otherwise, *E* shall be taken as 0.60 for pipe NPS 4 and smaller, or 0.80 for pipe larger than NPS 4.

(e) Weldability. Weldability shall be determined as follows. A qualified welder shall make a girth weld in the pipe. The weld shall then be tested in accordance with requirements of API 1104. The qualifying weld shall be made under the most severe conditions under which welding will be permitted in the field and using the same procedure as to be used in the field. The pipe shall be considered weldable if the requirements set forth in API 1104 are met. At least one such test weld shall be made for each 100 lengths of pipe on sizes larger than NPS 4. On sizes NPS 4 and smaller, one test will be required for each 400 lengths of pipe. If in testing the weld the requirements of API 1104 cannot be met, the weldability may be established by making chemical tests for carbon and manganese (see para. 823.23), and proceeding in accordance with the provisions of the ASME Boiler and Pressure Vessel Code, Section IX. The number of chemical tests shall be the same as required for circumferential weld tests stated above.

(f) Surface Defects. All pipe shall be examined for gouges, grooves, and dents and shall be qualified in accordance with the provisions of para. 841.24.

(g) Determination of Yield Strength. When the manufacturer's specified minimum yield strength, tensile strength, or elongation for the pipe is unknown, and no physical tests are made, the minimum yield strength for design shall be taken as not more than 24,000 psi. Alternatively, the tensile properties may be established as follows.

(1) Perform all tensile tests prescribed by API 5L except that the number of such tests shall be as follows:

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

(2) All test specimens shall be selected at random.

(3) If the yield–tensile ratio exceeds 0.85, the pipe shall not be used, except as provided in para. 817.12.

(h) S Value. For pipe of unknown specification, the yield strength, to be used as *S* in the formula of para. 841.11, in lieu of the specified minimum yield strength, shall be 24,000 psi, or determined as follows.

Determine the average value of all yield strength tests for a uniform lot. The value of *S* shall then be taken as the lesser of the following:

(1) 80% of the average value of the yield strength tests

(2) the minimum value of any yield strength test, provided, however, that in no case shall *S* be taken as greater than 52,000 psi

(i) Hydrostatic Test. New or used pipe of unknown specification and all used pipe, the strength of which is impaired by corrosion or other deterioration, shall be retested hydrostatically either length by length in a mill-type test or in the field after installation before being placed in service. The test pressure used shall establish the maximum allowable operating pressure, subject to limitations described in para. 841.111.

817.2 Reuse of Ductile Iron Pipe

817.21 The removal of a portion of an existing line of unknown specifications and the reuse of the pipe in the same line or in a line operating at the same or lower pressure is permitted, provided careful inspection indicates that the pipe is sound, permits the makeup of tight joints, and has an actual net wall thickness equal to or exceeding the requirements of para. 842.214. The pipe shall be leak-tested in accordance with para. 841.34 or 841.35.

817.22 Used pipe of known specifications may be reused in accordance with the provisions and specifications of para. 842.2 provided a careful inspection indicates the pipe is sound and permits the makeup of tight joints.

817.3 Reuse of Plastic Piping

Used plastic pipe and tubing of known specifications and dimensions that has been used in natural gas service only may be reused, provided that

Quick opening closures shall have pressure and temperature ratings equal to or in excess of the design requirements of the piping system to which they are attached.

Quick opening closures shall be equipped with safety locking devices in compliance with Section VIII, Division I, UG-35(b) of the BPV Code.

Weld end preparation shall be in accordance with Appendix I, Fig. I4.

831.372 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. [See para. 831.31(b).]

A00 **831.373 Closure Heads.** Closure heads such as flat, ellipsoidal (other than in para. 831.372), spherical, or conical heads are allowed for use under this Code. Such items may be designed in accordance with Section VIII, Division 1, of the BPV Code. For closure heads not designed to Section VIII, Division 1, of the BPV Code, the maximum allowable stresses for materials used in these closure heads shall be established under the provisions of para. 841 and shall not exceed 60% SMYS.

If welds are used in the fabrication of these heads, they shall be inspected in accordance with the provisions of Section VIII, Division 1 of the BPV Code.

Closure heads shall have pressure and temperature ratings equal to or in excess of the design requirement of the piping system to which they are attached.

831.374 Fabricated Closures. Orange-peel bull plugs and orange-peel swages are prohibited on systems operating at stress levels of 20% or more of the specified minimum yield strength of the pipe material. Fish tails and flat closures are permitted on pipe NPS 3 and smaller operating at less than 100 psi. Fish tails on pipe larger than NPS 3 are prohibited. Flat closures on pipe larger than NPS 3 shall be designed according to Section VIII, Division 1, of the BPV Code. (See para. 831.373.)

831.375 Bolted Blind Flange Connections. Bolted blind flange connections shall conform to para. 831.2.

831.4 Reinforcement of Welded Branch Connections

831.41 General Requirements. All welded branch connections shall meet the following requirements.

(a) When branch connections are made to pipe in the form of a single connection or in a header or manifold as a series of connections, the design must be adequate to control the stress levels in the pipe within safe limits. The construction shall accommodate the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, vibration, etc. The following paragraphs provide design rules for the usual combinations of the above loads, except for excessive external loads.

(b) 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 as defined in this paragraph as well as in Appendix F, Fig. F5.

(c) The required cross-sectional area, A_R, is defined as the product of d times t:

$$A_R = dt$$

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 by para. 841.11 for the design pressure and temperature

When the pipe wall thickness includes an allowance for corrosion or erosion, all dimensions used shall result after the anticipated corrosion or erosion has taken place.

(d) The area available for reinforcement shall be the sum of

(1) the cross-sectional area resulting from any excess thickness available in the header thickness over the minimum required for the header as defined in para. 831.41(c) and that lies within the reinforcement area as defined in para. 831.41(e)

(2) the cross-sectional area resulting from any excess thickness available in the branch wall thickness over the minimum thickness required for the branch and that lies within the reinforcement area as defined in para. 831.41(e)

(3) the cross-sectional area of all added reinforcing metal that lies within the reinforcement area, as defined in para. 831.41(e), including that of solid weld metal that is conventionally attached to the header and/or branch

(e) The area of reinforcement, shown in Appendix F, Fig. F5, is defined as a rectangle whose length shall extend a distance, d, on each side of the transverse center line of the finished opening and whose width shall extend a distance of $2\frac{1}{2}$ times the header wall thickness on each side of the surface of the header

wall. In no case, however, shall it extend more than $2\frac{1}{2}$ times the thickness of the branch wall from the outside surface of the header or of the reinforcement, if any.

(f) 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 stress for header and reinforcement material, respectively.

(g) The material used for ring or saddle reinforcement may be of specifications differing from those of 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, and provided it has welding qualities comparable to those of the pipe. No credit shall be taken for the additional strength of material having a higher strength than that of the part to be reinforced.

(h) When rings or saddles cover the weld between branch and header, a vent hole shall be provided in the ring or saddle 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 service to prevent crevice corrosion between pipe and reinforcing member, but no plugging material that would be capable of sustaining pressure within the crevice should be used.

(i) The use of ribs or gussets shall not be considered as contributing to reinforcement of the branch connection. This does not prohibit the use of ribs or gussets for purposes other than reinforcement, such as stiffening.

(j) 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 Appendix I, Figs. I1 and I2. The use of concave fillet welds is preferred to further minimize corner stress concentration. Ring or saddle reinforcement shall be attached as shown by Fig. I2. When a full fillet is not used, it is recommended that the edge of the reinforcement be relieved or chamfered at approximately 45 deg to merge with the edge of the fillet.

(k) Reinforcement rings and saddles shall be accurately fitted to the parts to which they are attached. Appendix I, Figs. I2 and I3 illustrate some acceptable forms of reinforcement.

(l) Branch connections attached at an angle less than 85 deg to the run become progressively weaker as the angle decreases. 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.

TABLE 831.42
REINFORCEMENT OF WELDED BRANCH CONNECTIONS, SPECIAL REQUIREMENTS

Ratio of Design Hoop Stress to Minimum Specified Yield Strength in the Header	Ratio of Nominal Branch Diameter to Nominal Header Diameter		
	25% or Less	More Than 25% Through 50%	More Than 50%
20% or less	(g)	(g)	(h)
More than 20% through 50 %	(d) (i)	(i)	(h) (i)
More than 50%	(c) (d) (e)	(b) (e)	(a) (e) (f)

GENERAL NOTE: The letters in the table correspond to the subparagraphs of para. 831.42.

831.42 Special Requirements. In addition to the requirements of para. 831.41, branch connections must meet the special requirements of the following paragraphs as given in Table 831.42.

(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 of the complete encirclement type, but may be of the pad type, saddle type, or a welding outlet fitting type.

(c) The reinforcement member may be of the complete encirclement type, pad type, saddle type, or welding outlet fitting type. The edges of reinforcement members should be tapered to the header thickness. It is recommended that legs of fillet welds joining the reinforcing member and header do not exceed the thickness of the header.

(d) Reinforcement calculations are not required for openings 2 in. and smaller in diameter; however, care should be taken to provide suitable protection against vibrations and other external forces to which these small openings are frequently subjected.

(e) All welds joining the header, branch, and reinforc-

consideration in the design and testing of the proposed pipeline.

841 STEEL PIPE

841.1 Steel Piping Systems Design Requirements

841.11 Steel Pipe Design Formula

(a) The design pressure for steel gas piping systems or the nominal wall thickness for a given design pressure shall be determined by the following formula (for limitations, see para. 841.111):

$$P = \frac{2St}{D} FET$$

where

D = nominal outside diameter of pipe, in.

E = longitudinal joint factor obtained from Table 841.115A [see also para. 817.13(d)]

F = design factor obtained from Table 841.114A. In setting the values of the design factor, F, due consideration has been given and allowance has been made for the various underthickness tolerances provided for in the pipe specifications listed and approved for usage in this Code.

P = design pressure, psig (see also para. 841.111)

S = specified minimum yield strength, psi, stipulated in the specifications under which the pipe was purchased from the manufacturer or determined in accordance with paras. 817.13(h) and 841.112. The specified minimum yield strengths of some of the more commonly used piping steels whose specifications are incorporated by reference herein are tabulated for convenience in Appendix D.

T = temperature derating factor obtained from Table 841.116A

t = nominal wall thickness, in.

(b) The design factor for pipelines in Location Class 1, Division 1 is based on gas pipeline operational experience at operation levels in excess of those previously recommended by this Code.

It should be noted that the user may be required to change out such pipe or reduce pressure to 0.72 SMYS maximum in accordance with para. 854.2.

(c) Fracture Control and Arrest. A fracture toughness criterion or other method shall be specified to control fracture propagation when a pipeline is designed to operate either at a hoop stress over 40% through 80% of SMYS in sizes NPS 16 or larger, or at a hoop stress over 72% through 80% of SMYS in sizes smaller than NPS 16.

When a fracture toughness criterion is used, control can be achieved by ensuring that the pipe has adequate ductility and either by specifying adequate toughness or installing crack arrestors on the pipeline to stop propagation.

(1) Brittle Fracture Control. To ensure that the pipe has adequate ductility, fracture toughness testing shall be performed in accordance with the testing procedures of supplementary requirements SR5 or SR6 of API 5L, or other equivalent alternatives. If the operating temperature is below 50°F, an appropriate lower test temperature shall be used. The appropriate lower test temperature shall be taken to be at or below the lowest expected metal temperature during pressure testing (if with air or gas) and during service, having regard to past recorded temperature data and possible effects of lower air and ground temperatures. The average shear value of the fracture appearance of three Charpy specimens from each heat shall not be less than 60%, and the all-heat average for each order per diameter, size, and grade shall not be less than 80%. Alternatively, when drop-weight tear testing is specified, at least 80% of the heats shall exhibit a fracture appearance shear area of 40% or more at the specified test temperature. A00

(2) Ductile Fracture Arrest. To ensure that the pipeline has adequate toughness to arrest a ductile fracture, the pipe shall be tested in accordance with the procedures of supplementary requirements 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)

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

(b) American Iron and Steel Institute (AISI)

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

(c) British Gas Council (BGC)

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

(d) British Steel Corporation (BSC)

$$CVN = 0.00119\,\sigma^2 R$$

where

CVN = full-size Charpy V-notch absorbed energy, ft-lb
R = pipe radius, in.
t = wall thickness, in.
σ = hoop stress, ksi

(99) *(3) Mechanical Crack Arrestors.* Mechanical crack arrestors consisting of sleeves, wire-rope wrap, heavy-wall pipe, or other suitable types have been shown to provide reliable methods of arresting ductile fracture. The mechanical crack arrestors shall be placed at intervals along the pipeline.

CAUTION: The requirements specified in (2) above assume the pipeline is transporting essentially pure methane and the pipe is similar in fracture behavior to that used to develop the empirical equations above. The presence of heavier hydrocarbons can cause the gas to exhibit two-phase behavior on sudden decompression and thus requires a greater Charpy energy to arrest propagating pipe fracture. Likewise, pipe that has been control rolled or quench and tempered may not behave as indicated by the equations and may also require a greater Charpy energy to arrest a propagating fracture. Calculations must be performed to determine if the decompression exhibits two-phase behavior, and an assessment must be made as to the applicability of the arrest equations where additional toughness is may be required. Otherwise, mechanical crack arrestors [see (3) above] should be installed, or the Charpy toughness requirements for arrest should be verified through experiments or additional calculations.

841.111 Limitations on Design Pressure *P* in Para. 841.11. The design pressure obtained by the formula in para. 841.11 shall be reduced to conform to the following:

(a) P for furnace butt welded pipe shall not exceed the restrictions of para. 841.11 or 60% of mill test pressure, whichever is the lesser.

(b) P shall not exceed 85% of the mill test pressure for all other pipes provided; however, that pipe, mill tested to a pressure less than 85% of the pressure required to produce a stress equal to the specified minimum yield, may be retested with a mill type hydrostatic test or tested in place after installation. In the event the pipe is retested to a pressure in excess of the mill test pressure, then P shall not exceed 85% of the retest pressure rather than the initial mill test pressure. It is mandatory to use a liquid as the test medium in all tests in place after installation where the test pressure exceeds the mill test pressure. This paragraph is not to be construed to allow an operating pressure or design pressure in excess of that provided for by para. 841.11.

841.112 Limitations on Specified Minimum Yield Strength *S* in Para. 841.11

(a) If the pipe under consideration is not new pipe purchased under a specification approved and listed in this Code, the value of S may be determined in accordance with one of the following:

(1) S value for new pipe qualified under para. 811.221 or 811.222

(2) S value for reuse of steel pipe qualified under one of the provisions of para. 817.1

(3) S value for pipe of unknown specification as determined by para. 817.13(h)

(b) When pipe that has been cold worked for meeting the specified minimum yield strength is subsequently heated to a temperature higher than 900°F for any period of time or over 600°F for more than 1 hr, the maximum allowable pressure at which it can be used shall not exceed 75% of the value obtained by use of the steel pipe design formula given in para. 841.11.

(c) In no case where the Code refers to the specified minimum value of a mechanical property shall the higher actual value of a property be substituted in the steel pipe design formula given in para. 841.11. If the actual value is less than the specified minimum value of a mechanical property, the actual value may be used where it is permitted by the Code, such as in para. 817.1 regarding the reuse of steel pipe.

841.113 Additional Requirements for Nominal Wall Thickness *t* in Para. 841.11

(a) The minimum wall thickness t required for pressure containment as determined by para. 841.11 may not be adequate for other forces to which the pipeline may be subjected. [See para. 840.1(a).] Consideration shall also be given to loading due to transportation or handling 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. Standard wall thickness, as prescribed in ASME B36.10M, shall be the least nominal wall thickness used for threaded and grooved pipe.

(b) Transportation, installation, or repair of pipe shall not reduce the wall thickness at any point to a thickness less than 90% of the nominal wall thickness as determined by para. 841.11 for the design pressure to which the pipe is to be subjected.

841.114 Design Factors *F* and Location Classes. The design factor in Table 841.114A shall be used for the designated Location Class. All exceptions to basic design factors to be used in the design formula are given in Table 841.114B.

TABLE 841.115A
LONGITUDINAL JOINT FACTOR, E

Spec. No.	Pipe Class	E Factor
ASTM A 53	Seamless	1.00
	Electric Resistance Welded	1.00
	Furnace Butt Welded: Continuous Weld	0.60
ASTM A 106	Seamless	1.00
ASTM A 134	Electric Fusion Arc Welded	0.80
ASTM A 135	Electric Resistance Welded	1.00
ASTM A 139	Electric Fusion Welded	0.80
ASTM A 211	Spiral Welded Steel Pipe	0.80
ASTM A 333	Seamless	1.00
	Electric Resistance Welded	1.00
ASTM A 381	Double Submerged-Arc-Welded	1.00
ASTM A 671	Electric Fusion Welded	
	Classes 13, 23, 33, 43, 53	0.80
	Classes 12, 22, 32, 42, 52	1.00
ASTM A 672	Electric Fusion Welded	
	Classes 13, 23, 33, 43, 53	0.80
	Classes 12, 22, 32, 42, 52	1.00
API 5L	Seamless	1.00
	Electric Resistance Welded	1.00
	Electric Flash Welded	1.00
	Submerged Arc Welded	1.00
	Furnace Butt Welded	0.60

GENERAL NOTE: Definitions for the various classes of welded pipe are given in para. 804.243.

TABLE 841.116A
TEMPERATURE DERATING FACTOR, T,
FOR STEEL PIPE

Temperature, °F	Temperature Derating Factor, T
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	0.867

GENERAL NOTE: For intermediate temperatures, interpolate for derating factor.

with the requirements of this Code shall be done under construction specifications. The construction specifications shall cover all phases of the work and shall be in sufficient detail to cover the requirements of this Code.

841.22 Inspection Provisions

841.221 The operating company shall provide suitable inspection. Inspectors shall be qualified either by experience or training. The inspector shall have the authority to order the repair or removal and replacement of any component found that fails to meet the standards of this Code.

841.222 The installation inspection provisions for pipelines and other facilities to operate at hoop stresses of 20% or more of the specified minimum yield strength shall be adequate to make possible at least the following inspections at sufficiently frequent intervals to ensure good quality of workmanship.

(a) Inspect the surface of the pipe for serious surface defects just prior to the coating operation. [See para. 841.242(a).]

(b) Inspect the surface of the pipe coating as it is lowered into the ditch to find coating lacerations that indicate the pipe might have been damaged after being coated.

(c) Inspect the fitup of the joints before the weld is made.

(d) Visually inspect the stringer beads before subsequent beads are applied.

(e) Inspect the completed welds before they are covered with coating.

(f) Inspect the condition of the ditch bottom just before the pipe is lowered in, except for offshore pipelines.

(g) Inspect the fit of the pipe to the ditch before backfilling, except for offshore pipelines.

(h) Inspect all repairs, replacements, or changes ordered before they are covered.

(i) Perform such special tests and inspections as are required by the specifications, such as nondestructive testing of welds and electrical testing of the protective coating.

(j) Inspect backfill material prior to use and observe backfill procedure to ensure no damage occurs to the coating in the process of backfilling.

841.23 Bends, Elbows, and Miters in Steel Pipelines and Mains. Changes in direction may be made by the use of bends, elbows, or miters under the limitations noted below.

841.231

(a) A bend shall be free from buckling, cracks, or other evidence of mechanical damage.

(b) The maximum degree of bending on a field cold bend may be determined by either method in the table below. The first column expresses the maximum deflection in an arc length equal to the nominal outside diameter, and the second column expresses the minimum radius as a function of the nominal outside diameter. (99)

Nominal Pipe Size	Deflection of Longitudinal Axis, deg	Minimum Radius of Bend in Pipe Diameters [see 841.231(c)]
Smaller than 12	841.231(d)	18*D*
12	3.2	18*D*
14	2.7	21*D*
16	2.4	24*D*
18	2.1	27*D*
20 and larger	1.9	30*D*

(c) A field cold bend may be made to a shorter minimum radius than permitted in (b) above, provided the completed bend meets all other requirements of this section, and the wall thickness after bending is not less than the minimum permitted by para. 841.11. This may be demonstrated through appropriate testing.

(d) For pipe smaller than NPS 12, the requirements of (a) above must be met, and the wall thickness after bending shall not be less than the minimum permitted by para. 841.11. This may be demonstrated through appropriate testing.

(e) Except for offshore pipelines, when a circumferential weld occurs in a bend section, it shall be subjected to radiography examination after bending.

(f) Hot bends made on cold worked or heat treated pipe shall be designed for lower stress levels in accordance with para. 841.112(b).

A00 *(g)* Wrinkle bends shall be permitted only on systems operating at less than 30% of the specified minimum yield strength. When wrinkle bends are made in welded pipe, the longitudinal weld shall be located on or near to the neutral axis of the bend. Wrinkle bends with sharp kinks shall not be permitted. Spacing of wrinkles shall be measured along the crotch of the pipe bend, and the peak to peak distance between the wrinkles shall exceed the diameter of the pipe. On pipe NPS 16 and larger, the wrinkle shall not produce an angle of more than $1\frac{1}{2}$ deg per wrinkle.

841.232 Mitered bends are permitted provided the following limitations are met:

(a) In systems intended to operate at 40% or more of the specified minimum yield strength, mitered bends are not permitted. Deflections caused by misalignment up to 3 deg are not considered as miters.

(b) In systems intended to operate at 10% or more but less than 40% of the specified minimum yield strength, the total deflection angle at each miter shall not exceed $12\frac{1}{2}$ deg.

(c) In systems intended to operate at less than 10% of the specified minimum yield strength, the total deflection angle at each miter shall not exceed 90 deg.

(d) In systems intended to operate at 10% or more of the specified minimum yield strength, the minimum distance between miters measured at the crotch shall not be less than one pipe diameter.

(e) Care shall be taken in making mitered joints to provide proper spacing and alignment and full penetration.

841.233 Factory-made, wrought-steel welding elbows or transverse segments cut therefrom may be used for changes in direction, provided that the arc length measured along the crotch is at least 1 in. on pipe sizes NPS 2 and larger.

841.24 Pipe Surface Requirements Applicable to Pipelines and Mains to Operate at a Hoop Stress of 20% or More of the Specified Minimum Yield Strength. Gouges, grooves, and notches have been found to be an important cause of pipeline failures, and all harmful defects of this nature must be prevented, eliminated, or repaired. Precautions shall be taken during manufacture, hauling, and installation to prevent the gouging or grooving of pipe.

841.241 Detection of Gouges and Grooves

(a) The field inspection provided on each job shall be suitable to reduce to an acceptable minimum the chances that gouged or grooved pipe will get into the finished pipeline or main. Inspection for this purpose just ahead of the coating operation and during the lowering-in and backfill operation is required.

(b) When pipe is coated, inspection shall be made to determine that the coating machine does not cause harmful gouges or grooves.

(c) Lacerations of the protective coating shall be carefully examined prior to the repair of the coating to determine if the pipe surface has been damaged.

841.242 Field Repair of Gouges and Grooves

(a) Injurious gouges or grooves shall be removed.

(b) Gouges or grooves may be removed by grinding to a smooth contour, provided that the resulting wall thickness is not less than the minimum prescribed by this Code for the conditions of usage. [See para. 841.113(b).]

(c) When the conditions outlined in para. 841.242(b) cannot be met, the damaged portion of pipe shall be cut out as a cylinder and replaced with a good piece. Insert patching is prohibited.

841.243 Dents

(a) A dent may be defined as a depression that produces a gross disturbance in the curvature of the pipe wall (as opposed to a scratch or gouge, which reduces the pipe wall thickness). The depth of a dent

CHAPTER V
OPERATING AND MAINTENANCE PROCEDURES

850 OPERATING AND MAINTENANCE PROCEDURES AFFECTING THE SAFETY OF GAS TRANSMISSION AND DISTRIBUTION FACILITIES

850.1 General

(a) Because of many variables, it is not possible to prescribe in a code a detailed set of operating and maintenance procedures that will encompass all cases. It is possible, however, for each operating company to develop operating and maintenance procedures based on the provisions of this Code, its experience, and its knowledge of its facilities and conditions under which they are operated that will be adequate from the standpoint of public safety. For operating and maintenance procedures relating to corrosion control, see Chapter VI.

(b) Upon initiating gas service in a pipeline designed and constructed or converted to gas service in accordance with this Code, the operating company shall determine the Location Class in accordance with Table 854.1(c).

850.2 Basic Requirements

Each operating company having gas transmission or distribution facilities within the scope of this Code shall

(a) have a written plan covering operating and maintenance procedures in accordance with the scope and intent of this Code

(b) have a written emergency plan covering facility failure or other emergencies

(c) operate and maintain its facilities in conformance with these plans

(d) modify the plans periodically as experience dictates and as exposure of the public to the facilities and changes in operating conditions require

(e) provide training for employees in procedures established for their operating and maintenance functions. The training shall be comprehensive and shall be designed to prepare employees for service in their area of responsibility.

(f) keep records to administer the plans and training properly

850.3 Essential Features of the Operating and Maintenance Plan

The plan prescribed in para. 850.2(a) shall include

(a) detailed plans and instructions for employees covering operating and maintenance procedures for gas facilities during normal operations and repairs

(b) items recommended for inclusion in the plan for specific classes of facilities that are given in paras. 851.2, 851.3, 851.4, 851.5, 851.6, and 861(d)

(c) plans to give particular attention to those portions of the facilities presenting the greatest hazard to the public in the event of an emergency or because of construction or extraordinary maintenance requirements

(d) provisions for periodic inspections along the route of existing steel pipelines or mains, operating at a hoop stress in excess of 40% of the specified minimum yield strength of the pipe material to consider the possibility of Location Class changes. It is not intended that these inspections include surveys of the number of buildings intended for human occupancy. (See para. 854.)

850.4 Essential Features of the Emergency Plan

850.41 Written Emergency Procedures

850.411 Each operating company shall establish written procedures that will provide the basis for instructions to appropriate operating and maintenance personnel that will minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures shall provide for the following:

(a) a system for receiving, identifying, and classifying emergencies that require immediate response by the operating company

(b) indicating clearly the responsibility for instructing employees in the procedures listed in the emergency plans and for training employees in the execution of those procedures

(c) indicating clearly those responsible for updating the plan

(d) establishing a plan for prompt and adequate handling of all calls that concern emergencies whether they are from customers, the public, company employees, or other sources

(e) establishing a plan for the prompt and effective response to a notice of each type of emergency

(f) controlling emergency situations, including the action to be taken by the first employee arriving at the scene

(g) the dissemination of information to the public

(h) the safe restoration of service to all facilities affected by the emergency after proper corrective measures have been taken

(i) reporting and documenting the emergency

850.42 Training Program. Each operating company shall have a program for informing, instructing, and training employees responsible for executing emergency procedures. The program shall acquaint the employee with the emergency procedures and how to promptly and effectively handle emergency situations. The program may be implemented by oral instruction, written instruction, and, in some instances, group instruction, followed by practice sessions. The program shall be established and maintained on a continuing basis with provision for updating as necessitated by revision of the written emergency procedures. Program records shall be maintained to establish what training each employee has received and the date of such training.

A00 **850.43 Liaison**

(a) Each operating company shall establish and maintain liaison with appropriate fire, police, and other public officials and public communications media.

(b) Each operating company must have a means of communication with appropriate public officials during an emergency.

(c) Emergency procedures, including the contingency plan under para. B855.1(e) must be prepared in coordination with appropriate public officials.

A00 **850.44 Educational Program.** An educational program shall be established to enable customers and the general public to recognize a gas emergency and report it to the appropriate officials. The educational program shall be tailored to the type of pipeline operation and the environment traversed by the pipeline and shall be conducted in each language that is significant in the community served. Operators of distribution systems shall communicate their programs to consumers and the general public in their distribution area. Operators of transmission systems shall communicate their programs to residents along their pipeline rights-of-way. Operators of sour gas pipelines subject to Chapter IX B shall notify residents affected by the contingency plan under para. B855.1(e) of the hazards of sour gas, the potential source of the gas, and protective measures to take in an emergency. The programs of operators in the same area shall be coordinated to properly direct reports of emergencies and to avoid inconsistencies.

850.5 Pipeline Failure Investigation

Each operating company shall establish procedures to analyze all failures and accidents for determining the cause and to minimize the possibility of a recurrence. This plan shall include a procedure to select samples of the failed facility or equipment for laboratory examination when necessary.

850.6 Prevention of Accidental Ignition

Smoking and all open flames shall be prohibited in and around structures, or areas under the control of the operating company containing gas facilities (such as compressor stations, meter and regulator stations, and other gas handling equipment), where possible leakage of gas constitutes a hazard of fire or explosion. Each operating company shall take steps to minimize the danger of accidental ignition of gas.

(a) When a hazardous amount of gas is to be vented into open air, each potential source of ignition shall first be removed from the area and adequate fire extinguishers shall be provided. All flashlights, lighting fixtures, extension cords, and tools shall be of a type approved for hazardous atmospheres. Blowdown connections that will direct the gas away from any electrical transmission lines must be installed or used.

(b) Suitable signs and flagmen or guards, if necessary, shall be posted to warn others approaching or entering the area of the hazard.

(c) To prevent accidental ignition by electric arcing, an adequate bonding cable should be connected to each side of any piping that is to be parted or joined, and any cathodic protection rectifiers in the area shall be turned off. When plastic pipe is being parted or joined, a spray of water or use of wet rags is advised to cover the surface to prevent static arcing.

(d) When cutting by torch or welding is to be performed, a thorough check shall first be made for the presence of a combustible gas mixture in the area outside of the pipeline. If found, the mixture shall be eliminated before starting welding or cutting. Monitoring of the air mixture should continue throughout the progress of the work.

(e) Should welding be anticipated on a pipeline filled with gas and the safety check under (d) above has been completed satisfactorily, the gas pressure must be controlled by a suitable means to keep a slight positive pressure in the pipeline at the welding area before starting work. Precautions should be taken to prevent a backdraft from occurring at the welding area.

(f) Before cutting by torch or welding on a line that may contain a mixture of gas and air, it shall be made safe by displacing the mixture with gas, air, or an inert gas. Caution must be taken when using an inert gas to provide adequate ventilation for all workers in the area.

stress cracking is found in any weld zone, a full encirclement welded split sleeve shall be installed using fillet welds. The sleeve shall then be pressurized by hot tapping the pipeline under the sleeve.

(e) All repairs performed under (a), (b), (c), and (d) above shall be tested and inspected as provided in para. 851.5.

851.43 Permanent Field Repair of Leaks and Nonleaking Corroded Areas

(a) If feasible, the pipeline shall be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing with pipe of equal or greater design strength.

(b) If it is not feasible to take the pipeline out of service, repairs shall be made by the installation of a full encirclement welded split sleeve unless a patch is chosen in accordance with (e) below, or unless corrosion is repaired with deposited weld metal in accordance with (f) below. If nonleaking corrosion is repaired with a full encirclement welded split sleeve, the circumferential fillet welds are optional.

(c) If the leak is due to a corrosion pit, the repair may be made by the installation of a properly designed bolt-on leak clamp.

(d) A small leak may be repaired by welding a nipple over it to vent the gas while welding and then installing an appropriate fitting on the nipple.

(e) Leaking or nonleaking corroded areas on pipe of not more than 40,000 psi specified minimum yield strength may be repaired by using a steel plate patch with rounded corners and with dimensions not in excess of one-half the circumference of the pipe fillet welded over the pitted area. The design strength of the plate shall be the same or greater than the pipe.

(f) Small corroded areas may be repaired by filling them with deposited weld metal from low-hydrogen electrodes. The higher the pressure and the greater the flow rate, the less is the chance of burn-through. At 20 V and 100 A, burn-through is unlikely to occur when the following actual wall thicknesses exist:

	Gas Velocity, ft/sec			
psia	0	5	10	20
15	0.320	. . .	. . .	. . .
500	0.300	0.270	0.240	0.205
900	0.280	0.235	0.190	0.150

This method of repair should not be attempted on pipe that is thought to be susceptible to brittle fracture.

(g) All repairs performed under (a), (b), and (d) above shall be tested and inspected as provided in 851.5.

851.44 Permanent Field Repair of Hydrogen Stress Cracking in Hard Spots and Stress Corrosion Cracking

(a) If feasible, the pipeline shall be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing with pipe of equal or greater design strength.

(b) If it is not feasible to take the pipeline out of service, repairs shall be made by the installation of a full encirclement welded split sleeve. In the case of stress corrosion cracking, the fillet welds are optional. If the fillet welds are made, pressurization of the sleeve is optional. The same applies to hydrogen stress cracking in hard spots except that a flat hard spot shall be protected with a hardenable filler or by pressurization of a fillet welded sleeve.

(c) All repairs performed under (a) and (b) above shall be tested and inspected as provided in para. 851.5.

851.5 Testing Repairs to Steel Pipelines or Mains Operating at Hoop Stress Levels at or Above 40% of the Specified Minimum Yield Strength

851.51 Testing of Replacement Pipe Sections. When a scheduled repair to a pipeline or main is made by cutting out the damaged portion of the pipe as a cylinder and replacing it with another section of pipe, the replacement section of pipe shall be subjected to a pressure test. The replacement section of pipe shall be tested to the pressure required for a new pipeline or main installed in the same location. The tests may be made on the pipe prior to installation, provided nondestructive tests meeting the requirements of para. 826 are made on all field girth butt welds after installation. If the replacement is made under controlled fire conditions (gas in the pipeline), full encirclement welded split sleeves may be used to join the pipe sections instead of butt welds. All sleeve welds should be radiographed. (See para. 851.52.)

851.52 Nondestructive Testing of Repairs, Gouges, Grooves, Dents, and Welds. If the defects are repaired by welding in accordance with the provisions of para. 851.4 and any of its subsections, the welding shall be examined in accordance with para. 826.

851.6 Pipeline Leak Records

Records shall be made covering all leaks discovered and repairs made. All pipeline breaks shall be reported in detail. These records along with leakage survey records, line patrol records, and other records relating to routine or unusual inspections shall be kept in the file of the operating company, as long as the section of line remains in service.

851.7 Pipeline Markers

(a) Signs or markers shall be installed where it is considered necessary to indicate the presence of a pipeline at road, highway, railroad, and stream crossings. Additional signs and markers shall be installed along the remainder of the pipeline at locations where there is a probability of damage or interference.

(b) Signs or markers and the surrounding right-of-way shall be maintained so markers can be easily read and are not obscured.

(c) The signs or markers shall include the words "Gas (or name of gas transported) Pipeline," the name of the operating company, and the telephone number (including area code) where the operating company can be contacted.

851.8 Abandoning of Transmission Facilities

Each operating company shall have a plan in its operating and maintenance procedures for abandoning transmission facilities. The plan shall include the following provisions:

(a) Facilities to be abandoned shall be disconnected from all sources and supplies of gas such as other pipelines, mains, crossover piping, meter stations, control lines, and other appurtenances.

(b) Facilities to be abandoned in place shall be purged of gas with an inert material and the ends shall be sealed, except that:

(c) after precautions are taken to determine that no liquid hydrocarbons remain in the facilities to be abandoned, then such facilities may be purged with air. If the facilities are purged with air, then precautions must be taken to determine that a combustible mixture is not present after purging. (See para. 841.275.)

(99) A00 851.9 Decommissioning of Transmission Facilities

Operators planning the decommissioning (temporary disconnect) of transmission facilities shall develop procedures for the decommissioning of facilities from service. The procedures shall include the following.

(a) Facilities to be decommissioned shall be isolated and sealed from all sources and supplies of gas such as other pipelines, mains, crossover piping, meter stations, control lines, and other appurtenances.

(b) Purge facilities to be commissioned with an inert material and effectively seal the ends. For facilities where purging is not necessary and where a need to restore to service exists, a small amount of gas can remain in the facilty provided the gas amount poses no potential hazard, and contains no corrosive contaminants exceeding pipeline quality standards such a water, carbon dioxide, and sulfides.

(c) After the facilities have been decommissioned, the maintenance procedures shall continue to be applied as if the facility were still in service.

(d) The cathodic protection shall be maintained with the periodic inspections and record keeping to continue as if the facility were still in service.

(e) For stations where blanket gas remains, the Emergency Shut Down (ESD) system shall remain in service. Some modification to the ESD system may be required to allow for a low pressure ESD. The hazardous gas and fire detectors should remain in service to blow the units and piping down, if necessary.

851.10 Recommissioning of Transmission Facilities A00

Operators planning to recommission (reactivate) trasmission facilities temporarily removed from service shall develop written procedures for recommissioning facilities to service. The procedures shall include the following.

(a) Before a facility is recommissioned, all maintenance and cathodic protection records shall be reviewed to ensure that the condition and integrity of the facility has been maintained during the decommissioned period.

(b) Facilities to be recommissioned that have been decommissioned for an extended period of time shall be repressured incrementally.

(c) A leak survey shall be performed after the facility has been recommissioned. Any defects or leaks discovered shall be repaired before the facility is back in full operation.

851.11 Repositioning a Pipeline in Service A00

When repositioning a pipeline in service, the following are some of the factors that shall be considered:

(a) deflection
(b) diameter, wall thickness, and grade of pipe
(c) pipeline pressure
(d) type of girth welds
(e) test and operating history
(f) presence of defects
(g) existing curvature
(h) bends
(i) valves and fittings

(j) terrain and soil conditions

(k) personnel safety considerations

(l) additional stresses caused by repositioning of the pipeline

852 DISTRIBUTION PIPING MAINTENANCE

852.1 Patrolling

Distribution mains shall be patrolled in areas where necessary to observe factors that may affect safe operation. The patrolling shall be considered in areas of construction activity, physical deterioration of exposed piping and supports, or any natural causes, which could result in damage to the pipe. The frequency of the patrolling shall be determined by the severity of the conditions that could cause failure or leakage and the subsequent hazards to public safety.

852.2 Leakage Surveys

Each operating company having a gas distribution system shall set up in its operating and maintenance plan a provision for making periodic leakage surveys on the system.

852.21 The types of surveys selected shall be effective for determining if potentially hazardous leakage exists. The following are some procedures that may be employed:

(a) surface gas detection surveys

(b) subsurface gas detector survey (including bar hole surveys)

(c) vegetation surveys

(d) pressure drop tests

(e) bubble leakage tests

(f) ultrasonic leakage tests

A detailed description of the various surveys and leakage detection procedures is shown in Appendix M.

852.22 The extent and frequency of leakage surveys shall be determined by the character of the general service area, building concentrations, piping age, system condition, operating pressure, and any other known condition (such as surface faulting, subsidence, flooding, or an increase in operating pressure) that has significant potential to either initiate a leak or to cause leaking gas to migrate to an area where it could result in a hazardous condition. Special one-time surveys should be considered following exposure of the gas distribution system to unusual stresses (such as those resulting from

earthquakes or blasting). The leakage survey frequencies shall be based on operating experience, sound judgment, and a knowledge of the system. Once established, frequencies shall be reviewed periodically to affirm that they are still appropriate. The frequencies of the leakage survey shall at least meet the following.

(a) Distribution systems in a principal business district should be surveyed at least annually. Such surveys shall be conducted using a gas detector and shall include tests of the atmosphere that will indicate the presence of gas in utility manholes, at cracks in the pavement and sidewalks, and at other locations that provide opportunities for finding gas leaks.

(b) The underground distribution system outside the areas covered by (a) above should be surveyed as frequently as experience indicates necessary, but not less than once every 5 years.

852.3 Leakage Investigation and Action

852.31 Leakage Classification and Repair. Leaks located by surveys and/or investigation should be evaluated, classified, and controlled in accordance with the criteria set forth in para. M5 of Appendix M.

Prior to taking any repair action, leaks should be pinpointed but only after it has been established that an immediate hazard does not exist or has been controlled by such emergency actions as evacuation, blocking an area off, rerouting traffic, eliminating sources of ignition, ventilating, or stopping the flow of gas. The pinpointing guidelines provided in para. M6 of Appendix M should be followed.

852.32 Investigation of Reports From Outside Sources. Any notification from an outside source (such as police or fire department, other utility, contractor, customer, or general public) reporting a leak, explosion, or fire, which may involve gas pipelines or other gas facilities, shall be investigated promptly. If the investigation reveals a leak, the leak should be classified and action should be taken in accordance with the criteria in para. M5 of Appendix M.

852.33 Odor or Indications From Foreign Sources. When potentially hazardous leak indications (such as natural, sewer, or marsh gas or gasoline vapors) are found to originate from a foreign source or facility or customer-owned piping, they shall be reported to the operator of the facility and, where appropriate, to the police department, fire department, or other governmental agency. When the company's pipeline is connected to a foreign facility (such as the customer's piping), necessary action, such as disconnecting or shutting off the flow of gas to the facility, shall be taken to eliminate the potential hazard.

852.34 Followup Inspections. While the excavation is open, the adequacy of leak repairs shall be checked by using acceptable methods. The perimeter of the leak area shall be checked with a gas detector. In the case of a Grade 1 leak repair as defined in Appendix M, where there is residual gas in the ground, a followup inspection should be made as soon as practicable after allowing the soil to vent to the atmosphere and stabilize, but in no case later than 1 month following the repair. In the case of other leak repairs, the need for a followup inspection should be determined by qualified personnel.

852.4 Requirements for Abandoning, Disconnecting, and Reinstating Distribution Facilities

852.41 Abandoning of Distribution Facilities. Each operating company shall have a plan for abandoning inactive facilities, such as service lines, mains, control lines, equipment, and appurtenances for which there is no planned use.

The plan shall also include the following provisions:

(a) If the facilities are abandoned in place, they shall be physically disconnected from the piping system. The open ends of all abandoned facilities shall be capped, plugged, or otherwise effectively sealed. The need for purging the abandoned facility to prevent the development of a potential combustion hazard shall be considered and appropriate measures shall be taken. Abandonment shall not be completed until it has been determined that the volume of gas or liquid hydrocarbons contained within the abandoned section poses no potential hazard. Air or inert gas may be used for purging, or the facility may be filled with water or other inert material. (See para. 841.275.) If air is used for purging, the operating company shall determine that a combustible mixture is not present after purging. Consideration shall be given to any effects the abandonment may have on an active cathodic protection system, and appropriate action shall be taken.

(b) In cases where a main and the service lines connected to it are abandoned, insofar as service lines are concerned, only the customer's end of such service lines need to be sealed as stipulated above.

(c) Service lines abandoned from the active mains should be disconnected as close to the main as practicable.

(d) All valves left in the abandoned segment should be closed. If the segment is long and there are few line valves, consideration should be given to plugging the segment at intervals.

(e) All above-grade valves, risers, and vault and valve box covers shall be removed. Vault and valve box voids shall be filled with suitable compacted backfill material.

852.42 Temporarily Disconnected Service. Whenever service to a customer is temporarily discontinued, one of the following shall be complied with:

(a) The valve that is closed to prevent the flow of gas to the customer shall be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operating company.

(b) A mechanical device or fitting that will prevent the flow of gas shall be installed in the service line or in the meter assembly.

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

852.43 Test Requirements for Reinstating Abandoned Facilities and Temporarily Disconnected Service Lines. Facilities previously abandoned shall be tested in the same manner as new facilities before being reinstated.

Service lines previously abandoned shall be tested in the same manner as new service lines before being reinstated.

Service lines temporarily disconnected because of main renewals or other planned work shall be tested from the point of disconnection to the service line valve in the same manner as new service lines before reconnecting, except

(a) when provisions to maintain continuous service are made, such as by installation of a bypass, any portion of the original service line used to maintain continuous service need not be tested; or

(b) when the service line has been designed, installed, tested, and maintained in accordance with the requirements of this Code.

852.5 Plastic Pipe Maintenance

852.51 Pinching and Reopening of Thermoplastic Pipe and Tubing for Pressure Control

(a) Before thermoplastic pipe and tubing is pinched and reopened, it is required that investigations and tests be made to determine that the particular type, grade, size, and wall thickness of pipe or tubing of the same manufacture can be pinched and reopened without causing failure under the conditions that will prevail at the time of the pinching and reopening.

(b) After compliance with (a) above, whenever thermoplastic pipe or tubing is pinched and reopened, it is required that:

(1) the work be done with equipment and procedures that have been established and proven by test to be capable of performing the operation safely and effectively

(2) the pinched and reopened area of the pipe or tubing be reinforced in accordance with the appropriate provisions of para. 852.52, unless it has been determined by investigation and test that pinching and reopening does not significantly affect the long-term properties of the pipe or tubing.

852.52 Repair of Plastic Pipe or Tubing. If at any time an injurious defect, groove, gouge, or dent is found in plastic pipe or tubing, the damaged or defective section shall be replaced unless satisfactory repairs are made. **A00**

The damaged section can be cut out and replaced in accordance with applicable provisions of para. 842.4, Installation of Plastic Piping. The replacement pipe or tubing shall be 100 percent visually inspected inside and out. There shall be no visible defects on the inside or outside of the replacement pipe or tubing. The replacement pipe or tubing shall be leak tested at available system pressure.

Repairs shall be made in accordance with qualified procedures that have been established and proven by test and in accordance with the following:

(a) The recommendations of the plastic manufacturer shall be taken into consideration when determining the type of repair to be made. Special consideration shall be given to the extent of fiber damage in the case of thermosetting plastic pipe.

(b) If a patch or full encirclement sleeve is used, it shall extend at least $\frac{1}{2}$ in. beyond the damaged area.

(c) If a full encirclement split sleeve is used, the joining line between the halves of the sleeve shall be as far as possible from the defect, but in no case closer than $\frac{1}{2}$ in. Suitable precautions shall be taken to ensure a proper fit at the longitudinal seam.

(d) The patch or sleeve material shall be the same type and grade as the pipe or tubing being repaired. Wall thickness of the patch or sleeve shall be at least equal to that of the pipe or tubing.

(e) The method of attachment of the patch or sleeve shall be compatible with the material and shall conform to the applicable provisions of para. 842.392. Precau-

tions shall be taken to ensure a proper fit and a complete bond between the patch or sleeve and the pipe being repaired. The patch or sleeve shall be clamped or held in place by other suitable means during the setting or curing of the bonding material or during the hardening of a heat-fusion bond. Excess solvent cement shall be removed from the edges of the patch or sleeve.

CHAPTER VIII
OFFSHORE GAS TRANSMISSION

A800 OFFSHORE GAS TRANSMISSION

(99) **A801 GENERAL**

Chapter VIII pertains only to offshore gas transmission systems as defined in para. A802.1. With the exception of sections A840 through A842, A844, and A847, this Chapter is organized to parallel the numbering and the content of the first six chapters of the Code. All provisions of the first six chapters of the Code are also requirements of this Chapter unless specifically modified herein. Chapter VII is not applicable. With the exceptions noted above, paragraph designations follow those in the first six chapters with the prefix "A."

A802 SCOPE AND INTENT

A802.1 Scope

This Chapter of the Code covers the design, material requirements, fabrication, installation, inspection, testing, and safety aspects of operation and maintenance of offshore gas transmission systems. For this Chapter, offshore gas transmission systems include offshore gas pipelines, pipeline risers, offshore gas compressor stations, pipeline appurtenances, pipe supports, connectors, and other components as addressed specifically in the Code.

A802.2 Intent

The intent of this Chapter is to provide adequate requirements for the safe and reliable design, installation, and operation of offshore gas transmission systems. Requirements of this Chapter supplement the requirements of the remainder of the Code. It is therefore not the intent of this Chapter to be all inclusive, and provisions must be made for any special considerations that are not specifically addressed.

It is not the intent of this Chapter to prevent the development and application of new equipment and technologies. Such activity is encouraged as long as the safety and reliability requirements of the Code are satisfied.

A802.3 Offshore Gas Transmission A00

See Chapter VIII for additional requirements and definitions applicable to offshore gas transmission systems.

A803 OFFSHORE GAS TRANSMISSION DEFINITIONS A00

accidental loads: any unplanned load or combination of loads caused by human intervention.

breakaway coupling: a component introduced into the pipeline to allow the pipeline to separate when a predetermined axial load is applied to the coupling.

buckle: a condition where the pipeline has undergone sufficient plastic deformation to cause permanent wrinkling in the pipe wall or excessive cross sectional deformation caused by bending, axial, impact, and/or torsional loads acting alone or in combination with hydrostatic pressure.

buckle arrestor: any device attached to or made a part of the pipe for arresting a propagating buckle.

buckle detector: any means for detecting dents, excessive ovalization, or buckles in a pipeline.

column buckling: buckling of a beam or pipe under compressive axial load in which loads cause unstable lateral deflection.

connectors: any component, except flanges, used for mechanically joining two sections of pipe.

external hydrostatic pressure: pressure acting on any external surface resulting from its submergence in water.

flexible pipe: pipe that is

(a) manufactured from both metal and nonmetal components

(b) capable of allowing large deflections without adversely affecting the pipe's integrity

(*c*) intended to be an integral part of the permanent product transportation system

Flexible pipe does not include solid steel pipe, plastic pipe, fiber reinforced plastic pipe, rubber hose, or solid steel pipes lined with nonsteel linings or coatings.

hyperbaric weld: a weld performed at ambient hydrostatic pressure in a submerged chamber from which the water has been removed from the surfaces to be welded.

offshore: the area beyond the line of ordinary high water along the portion of the coast that is in direct contact with the open seas and beyond the line marking the seaward limit of inland coastal waters.

offshore pipeline riser: the vertical or near vertical portion of an offshore pipeline between the platform piping and the pipeline at or below the seabed, including a length of pipe of at least five pipe diameters beyond the bottom elbow, bend, or fitting. Due to the wide variety of configurations, the exact location of transition between pipeline, pipeline riser, and platform piping must be selected on a case-by-case basis.

offshore pipeline system: all components of a pipeline installed offshore for transporting gas other than production facility piping. Tanker or barge loading hoses are not considered part of the offshore pipeline system.

offshore platform: any man-made fixed or permanently anchored structure or artificial island located offshore.

pipe collapse: flattening deformation of the pipe resulting in loss of cross-sectional strength and circular shape, which is caused by excessive external hydrostatic pressure acting alone.

platform piping: due to a wide variety of configurations, the exact location of the transition between the offshore pipeline riser(s), the platform piping, and the production facility shall be selected on a case-by-case basis.

(a) On offshore platforms where hydrocarbons are produced, platform piping consists of all the gas transmission piping, appurtenances, and components that are between the production facility and the off-shore pipeline riser(s). This includes any gas compressors and piping that are not a part of the production facility.

(b) On offshore platforms where hydrocarbons are not produced, platform piping consists of all the gas transmission piping, compressors, appurtenances, and components between the offshore pipeline risers.

propagating buckle: a buckle that progresses rapidly along a pipeline caused by the effect of external hydrostatic pressure on a previously formed buckle, local collapse, or other cross-sectional deformation.

pull tube: a conduit attached to an offshore platform through which a riser can be installed.

pull-tube riser: riser pipe or pipes installed through a pull tube.

return interval: time interval between successive events of design environmental conditions being equalled or exceeded.

soil liquefaction: a soil condition, typically caused by dynamic cyclic loading (e.g., earthquake, waves) where the effective shear stresses in the soil are reduced to zero, and the soil exhibits the properties of a liquid.

splash zone: the area of the pipeline riser or other pipeline components that is intermittently wet and dry due to wave and tidal action.

weight coating: any coating attached to the pipeline for increasing the pipeline specific gravity.

A811 QUALIFICATION OF MATERIALS AND EQUIPMENT (99) A00

Plastic pipe, plastic pipe with nonmetallic reinforcement, cast iron pipe, and ductile iron pipe shall not be used for transporting natural gas.

A814 MATERIAL SPECIFICATIONS (99)

A814.1 (99) A00

Concrete weight coating materials (cement, aggregate, reinforcing steel) shall meet or exceed the requirements of applicable ASTM standards.

Flexible pipe shall be manufactured from materials meeting the requirements of applicable ASTM or ASME standards.

Steel line pipe with a longitudinal joint factor of 1.00 in Table 841.115A shall be used.

A814.2 (99)

In addition to the requirements contained in referenced standards, certain other requirements may be considered for pipe and other components used offshore, depending on water depth, water temperature, internal pressure, product composition, product temperature, installation method and/or other loading conditions. Thus, consideration may include one or more of the following:

(a) wall thickness tolerance

(b) outside diameter tolerance

(c) out-of-roundness

(d) maximum and minimum yield and tensile strengths

(*e*) maximum carbon equivalent
(*f*) fracture toughness
(*g*) hardness
(*h*) pipe mill hydrostatic testing and other mechanical testing

(99) ## A816 TRANSPORTATION OF LINE PIPE

Transportation by truck or other road vehicles shall be performed in such a manner as to avoid damage to the pipe. Provisions shall be made to protect the pipeline corrosion coating, end bevel, and weight coating from damage.

A00 ## A817 CONDITIONS FOR THE REUSE AND REQUALIFICATION OF PIPE

A00 ### A817.1 Unidentified Line Pipe

Unidentified line pipe shall not be used for subsea pipelines.

A00 ### A817.2 Requalification of Pipeline Systems

A pipeline system that has previously been used for gas transmission service may be requalified, subject to the following conditions:

(a) the pipeline system meets the design considerations in Sections A841, A842, and A843; and

(b) the pipeline system meets the hydrotesting requirements in Sections A847.1 through A847.6. In addition, if the pipeline system is moved, it shall also meet the testing for buckles requirement in Section A847.7.

A00 ### A817.3 Reuse of Pipe

Used pipe may be reused, subject to the following conditions:

(a) the pipe meets the design considerations in Sections A841, A842, and A843;

(b) the pipe meets the testing requirements in Section A847; and

(c) the pipe shall be inspected per para. 817.13 to identify any defects that impair the serviceability of the pipe. If such defects are identified, they shall be removed or repaired.

A820 WELDING OFFSHORE PIPELINES

A821 GENERAL

(99) ### A821.1 Scope

This Section concerns the welding of carbon steel materials that are used in a pipeline in the offshore environment. The welding covered may be performed under atmospheric or hyperbaric conditions.

A821.2 Welding Processes

The welding may be done by any process or combination of processes that produce welds that meet the procedure qualification requirements of this Code and can be inspected by conventional means.

A821.3 Requirements

(a) Prior to atmospheric welding of any pipe, piping components, or related equipment, Welding Procedure Specifications shall be written and the procedure shall be qualified. The approved procedure shall include all of the applicable details listed in API Standard 1104.

(b) Prior to hyperbaric welding of any pipe, piping components, or related equipment, Welding Procedure Specifications shall be written and the procedure shall be qualified. The approved procedure shall include all of the applicable details listed in API Standard 1104 and ANSI/AWS D3.6.

(c) Each welder or welding operator shall be qualified for the established procedure before performing any welding on any pipe, piping component, or related equipment installed in accordance with this Code.

(d) Welding procedure qualifications, as well as welder or welding operator qualifications, are valid only within the specified limits of the welding procedure. If changes are made in certain details, called "essential variables" or "essential changes," additional qualification is required. API Standard 1104 essential variables shall take precedence in matters not affected by the underwater environment, and ANSI/AWS D3.6 shall govern those essential changes related to the underwater welding environment and working conditions.

A823 QUALIFICATION OF PROCEDURES AND WELDERS

Qualification of procedures and welders shall be in accordance with the requirements of para. 823, except paras. 823.1 and 823.2 do not apply offshore.

(a) Welding procedures and welders performing atmospheric welding under this section shall be qualified under API Standard 1104, except that for applications in which design, materials, fabrication, inspection, and testing are in accordance with BPV Code, Section VIII, welding procedures and welders shall be qualified under BPV Code, Section IX.

(b) Welding procedures and welders performing hyperbaric welding under this section shall be qualified in accordance with the testing provisions of API Stan-

dard 1104 as supplemented by ANSI/AWS D3.6, Specification for Underwater Welding for Type "O" Welds.

(99) A825 STRESS RELIEVING

Stress relieving requirements may be waived, regardless of wall thickness, provided that it can be demonstrated that a satisfactory welding procedure without the use of postweld heat treatment has been developed. Such a demonstration shall be conducted on materials and under conditions that simulate, as closely as practical, the actual production welding. Measurements shall be taken of the tensile, toughness, and hardness properties of the weld and heat-affected zone. No stress relieving will be required if

(a) the measurements indicate that the metallurgical and mechanical properties are within the limits specified for the materials and intended service

(b) an engineering analysis is conducted to ensure that the mechanical properties of the weldment and the residual stresses without postweld heat treatment are satisfactory for the intended service. In some cases, measurement of residual stresses may be required.

A826 WELDING AND INSPECTION TESTS

A826.2 Inspection and Tests for Quality Control of Welds on Piping Systems (99)

A826.21 Extent of Examination. One hundred percent of the total number of circumferential field butt welds on offshore pipelines shall be nondestructively inspected, if practical, but in no case shall less than 90% of such welds be inspected. The inspection shall cover 100% of the length of such inspected welds. (99)

(99) **A826.22 Standard of Acceptability.** All welds that are inspected must meet the standards of acceptability of API Standard 1104 or BPV Code, Section VIII, as appropriate for the service of the weld, or be appropriately repaired and reinspected or removed.

(99) **A826.23 Alternative Flaw Acceptance Limits.** For girth welds on a pipeline, alternative flaw acceptance limits may be established based on fracture mechanics analyses and fitness-for-purpose criteria as described in API Standard 1104. Such alternative acceptance standards shall be supported by appropriate stress analyses, supplementary welding procedure test requirements, and nondestructive examinations beyond the minimum requirements specified herein. The accuracy of the nondestructive techniques for flaw depth measurement shall be verified by sufficient data to establish probabilities for the proposed inspection error allowance.

A830 PIPING SYSTEM COMPONENTS AND FABRICATION DETAILS

A830.1 General

The purpose of this Section is to provide a set of criteria for system components to be used in an offshore application.

(99) A831 PIPING SYSTEM COMPONENTS

Cast iron or ductile iron shall not be used in flanges, fittings, or valve shell components.

All system components for offshore applications shall be capable of safely resisting the same loads as the pipe in the run in which they are included, except "weak links" (e.g., break-away couplings) designed into a system to fail under specific loads. Consideration should be given to minimizing stress concentrations.

System components which are not specifically covered in para. 831 shall be validated for fitness by either

(a) documented full scale prototype testing of the components or special assemblies, or

(b) a history of successful usage of these components or special assemblies produced by the same design method. Care should be exercised in any new application of existing designs to ensure suitability for the intended service.

(99) A832 EXPANSION AND FLEXIBILITY

Thermal expansion and contraction calculations shall consider the temperature differential between material temperature during operations and material temperature during installation.

A834 SUPPORTS AND ANCHORAGE FOR EXPOSED PIPING

Supports and anchorage for platform piping and risers shall conform to the requirements of para. 834, except that no attachment, other than an encircling member, shall be welded directly to the pipeline. (See para. A842.27.)

A835 ANCHORAGE FOR BURIED PIPING (99)

Thermal expansion and contraction calculations shall consider the effects of fully saturated backfill material on soil restraint.

When a submerged pipeline is to be laid across a known fault zone, or in an earthquake-prone area where new faults are a possibility, consideration shall be given to the need for flexibility in the pipeline system and its components to minimize the possibility of damage due to seismic activity.

The requirements of para. 835.51 for header and branch connections are not applicable to offshore submerged piping systems. An appropriate means of preventing undue stresses at offshore submerged piping connections is to provide adequate flexibility at branch connections on the seabed.

A840 DESIGN, INSTALLATION, AND TESTING

A840.1 General Provisions (99)

The design, installation, and testing of offshore gas transmission systems shall be in accordance with Chapter IV as specifically modified by the provisions of Chapter VIII. Also, all provisions of Chapter IV that depend on location class and construction type do not apply to offshore gas transmission systems, except that offshore pipelines approaching shoreline areas shall be additionally designed and tested consistently with class location provisions as determined in para. A840.2.

A840.2 Shoreline Approaches (99)

Offshore pipelines approaching shoreline areas shall be additionally designed and tested consistently with class location provisions as determined in section 840, except that

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TABLE A842.22
DESIGN FACTORS FOR OFFSHORE PIPELINES, PLATFORM PIPING, AND PIPELINE RISERS

	F_1	F_2	F_3
Location	Hoop Stress	Longitudinal Stress	Combined Stress
Pipeline	0.72	0.80	0.90
Platform piping and risers	0.50	0.80	0.90 [Note (1)]

NOTE:
(1) The wall thickness used in the calculation of combined stress for platform piping and risers shall be based upon specified minimum wall thickness, including manufacturing, corrosion, and erosion allowances.

A842.2 Strength Considerations During Operations

A842.21 Operational and Design Criteria

A842.211 Pipelines and risers shall be designed against the following possible modes of failure, as appropriate:

(a) excessive yielding
(b) buckling
(c) fatigue failure
(d) ductile fracture
(e) brittle fracture
(f) loss of in-place stability
(g) propagating fracture
(h) corrosion
(i) collapse

A842.212 Furthermore, consideration shall be given to impacts due to

(a) foreign objects
(b) anchors
(c) trawlboards
(d) vessels, ice keels, etc.

A842.22 Design Against Yielding

A842.221 Hoop Stress. For pipelines and risers the tensile hoop stress due to the difference between internal and external pressures shall not exceed the values given below:

NOTE: Sign convention is such that tension is positive and compression is negative.

$$S_h \le F_1 S T$$

$$S_h = (P_i - P_e)\frac{D}{2t}$$

where
D = nominal outside diameter of pipe, in.
F_1 = hoop stress design factor from Table A842.22
P_e = external pressure, psi
P_i = internal design pressure, psi
S = specified minimum yield strength, psi
S_h = hoop stress, psi
T = temperature derating factor from Table 841.116A
t = nominal wall thickness, in.

A842.222 Longitudinal Stress. For pipelines and risers the longitudinal stress shall not exceed values found from (99)

$$|S_L| \le F_2 S$$

where
A = cross sectional area of pipe material, in.^{2}
F_a = axial force, lbs
F_2 = longitudinal stress design factor from Table A842.22
M_i = in-plane bending moment, in.-lb
M_o = out-plane bending moment, in.-lb
S = specified minimum yield strength, psi
S_L = maximum longitudinal stress, psi (positive tensile or negative compressive)
= $S_a + S_b$ or $S_a - S_b$, whichever results in the larger stress value
S_a = axial stress, psi (positive tensile or negative compressive)
= F_a / A
S_b = resultant bending stress, psi
= $[(i_i M_i)^2 + (i_o M_o)^2]^{1/2}/z$
i_i = in-plane stress intensification factor from Appendix E
i_o = out-plane stress intensification factor from Appendix E
z = section modulus of pipe, in.^{3}
$| \; |$ = absolute value

A842.223 Combined Stress. For pipelines and risers the combined stress shall not exceed the value given by the maximum shear stress equation (Tresca combined stress): (99)

$$2\left[\left(\frac{S_L - S_h}{2}\right)^2 + S_t^{\,2}\right]^{1/2} \leq F_3 S$$

where

A = cross-sectional area of pipe material, in.^{2}

F_a = axial force, lbs

F_3 = combined stress design factor from Table A842.22

M_i = in-plane bending moment, in.-lb

M_o = out-plane bending moment, in.-lb

M_t = torsional moment, in.-lb

S = specified minimum yield strength, psi
S_L = maximum longitudinal stress, psi (positive tensile or negative compressive)
= $S_a + S_b$ or $S_a - S_b$, whichever results in the larger stress value
S_a = axial stress, psi (positive tensile or negative compressive)
= F_a / A
S_b = resultant bending stress, psi
= $[(i_i M_i)^2 + (i_o M_o)^2]^{1/2}/z$
S_h = hoop stress, psi
S_t = torsional stress, psi
i_i = in-plane stress intensification factor from Appendix E
i_o = out-plane stress intensification factor from Appendix E
z = section modulus of pipe, in.^{3}

Alternatively, the Maximum Distortional Energy Theory (Von Mises combined stress) may be used for limiting combined stress values. Accordingly, the combined stress should not exceed values given by

$$(S_h{}^2 - S_L S_h + S_L{}^2 + 3S_t{}^2)^{1/2} \leq F_3 S$$

A842.23 Alternate Design for Strain. In situations where the pipeline experiences a predictable noncyclic displacement of its support (e.g., fault movement along the pipeline route or differential subsidence along the line) or pipe sag before support contact, the longitudinal and combined stress limits need not be used as a criterion for safety against excessive yielding, so long as the consequences of yielding are not detrimental to the integrity of the pipeline. The permissible maximum longitudinal strain depends on the ductility of the material, any previously experienced plastic strain, and the buckling behavior of the pipe. Where plastic strains are anticipated, the pipe eccentricity, pipe out-of-roundness, and the ability of the weld to undergo such strains without detrimental effect should be considered. Similarly, the same criteria may be applied to the pipe during construction (e.g., pull-tube or bending shoe risers).

A842.24 Design Against Buckling and Ovalization. Avoidance of buckling of the pipeline and riser during operation shall be considered in design. Modes of buckling that may be possible include

(a) local buckling of the pipe wall

(b) propagation buckling following local buckling

(c) column buckling

A842.25 Design Against Fatigue. Stress fluctuations of sufficient magnitude and frequency to induce significant fatigue should be considered in design.

Loadings that may affect fatigue include:

(a) pipe vibration, such as that induced by vortex shedding

(b) wave action

Pipe and riser spans shall be designed so that vortex induced resonant vibrations are prevented, whenever practical. When doing so is impractical, the total resultant stresses shall be less than the allowable limits in para. A842.22, and such that fatigue failure should not result during the design life of the pipeline.

A842.26 Design Against Fracture. Materials used for pipelines transporting gas or gas-liquid mixtures under high pressure should have reasonably high resistance to propagating fractures at the design conditions, or other methods shall be used to limit the extent of a fracture.

A842.27 Design of Clamps and Supports. Clamps and supports shall be designed such that a smooth transfer of loads is made from the pipeline or riser to the supporting structure without highly localized stresses due to stress concentrations. When members are to be welded to the pipe they shall fully encircle the pipe and be welded to the pipe by a full encirclement weld. The support shall be attached to the encircling member and not the pipe.

All welds to the pipe shall be nondestructively tested. Clamps and supports shall be designed in accordance with the requirements of API RP 2A, Section 3.

Clamp and support design shall consider the corrosive effects of moisture retaining gaps and crevices and galvanically dissimilar metals.

A842.28 Design of Connectors and Flanges. Connectors and flanges shall be such that smooth transfer of loads is made without high localized stresses or excessive deformation of the attached pipe.

Connectors and flanges shall have a level of safety against failure by yielding and failure by fatigue that is comparable to that of the attached pipeline or riser.

A842.29 Design of Structural Pipeline Riser Protectors. Where pipeline risers are installed in locations subject to impact from marine traffic, protective devices shall be installed in the zone subject to damage to protect the pipe and coating.

(2) Radius of Exposure Equations

(a) Radius of exposure equation to the 100-ppm level of H_2S after dispersal:

$$X = [(1.589)\,M\,Q]^{0.6258}$$

A00 *(b)* Radius of exposure equation to the 500-ppm level of H_2S after dispersal:

$$X = [(0.4546)\,M\,Q]^{0.6258}$$

where

M = mol fraction of hydrogen sulfide in the gaseous mixture

Q = maximum volume determined to be available for escape in cubic feet per day corrected to 14.65 psia and 60°F

X = radius of exposure (ROE) in feet

(3) Metric Equations

(a) 100-ppm level of H_2S after dispersal:

$$X_m = [(8.404)\,M\,Q_m]^{0.6258}$$

(b) 500-ppm level of H_2S after dispersal:

$$X_m = [(2.404)\,M\,Q]^{0.6258}$$

where

M = mol fraction of hydrogen sulfide in the gaseous mixture

Q_m = maximum volume determined to be available for escape in cubic meters per day corrected to 1.01 bars and 15.6°C.

X_m = radius of exposure (ROE) in meters

NOTE: The equations assume a 24-hr release. When a pipeline segment can be isolated in less than 24 hr, appropriate reductions in (Q) may be used.

(4) Examples of 100-ppm and 500-ppm ROE for various 24-hr releases and H_2S mol fractions are as follows.

	100-ppm ROE	
ROE ft, X	Release MMSCFD Q(1,000,000)	H_2S Mol Fraction
1,165	1	0.05
3,191	5	0.05
4,924	10	0.05
7,597	20	0.05
9,792	30	0.05
1,798	1	0.1
4,924	5	0.1
7,597	10	0.1
11,723	20	0.1
15,109	30	0.1
2,775	1	0.2
7,597	5	0.2
11,723	10	0.2
18,090	20	0.2
23,315	30	0.2

	500-ppm ROE	
ROE ft, X	Release MMSCFD Q(1,000,000)	H_2S Mol Fraction
533	1	0.05
1,458	5	0.05
2,250	10	0.05
3,472	20	0.05
4,474	30	0.05
822	1	0.1
2,250	5	0.1
3,472	10	0.1
5,357	20	0.1
6,904	30	0.1
1,268	1	0.2
3,472	5	0.2
5,357	10	0.2
8,266	20	0.2
10,654	30	0.2

B850.4 Essential Features of the Emergency Plan

B850.42 Training Program. In addition to conventional training, all sour gas operation and maintenance line personnel shall be trained in

(a) hazards and characteristics of H_2S

(b) effect on metal components of the lines and equipment

(c) safety precautions

(d) operation of safety equipment and life support systems

(e) corrective action and shutdown procedures

B851 PIPELINE MAINTENANCE

B851.7

(d) In addition to each sign required in subpara. 851.7(c) of Chapter V, for operations where the 100-ppm radius of exposure is greater than 50 ft (15.2 m), a "POISON GAS" sign shall be installed.

All surface facilities shall also be marked with "POISON GAS" signs.

B851.10

When blowing down sour gas lines, consideration shall be given to the use of suitable permanent or temporary flare systems.

B855 CONCENTRATIONS OF PEOPLE IN LOCATION CLASSES 1 AND 2

B855.1

(c) Security. Unattended fixed surface facilities should be protected from public access when located within $\frac{1}{4}$ mile of a residential, commercial, or other inhabited or occupied structure; bus stop; public park; or similarly populated area.

(1) The protection should be provided by fencing and locking or removal of valves and instrumentation and plugging of ports, or other similar means.

(2) Surface pipeline is not considered a fixed surface facility.

(d) Additional control and safety procedures or safety devices should be installed and maintained to prevent the undetected continuing release of hydrogen sulfide if any of the following conditions exist:

(1) The 100-ppm radius of exposure is in excess of 50 ft (15.2 m) and includes any part of a public area except a public road.

(2) The 500-ppm radius of exposure is greater than 50 ft (15.2 m) and includes any part of a public road.

(3) The 100-ppm radius of exposure is greater than 3,000 ft (915 m).

(e) Contingency Plan. Operations subject to subpara. (d) above shall have a written contingency plan prepared and given to state and local emergency response authorities. Plans shall include maps, location of block valves, valve keys, and keys for locks.

B860 CORROSION CONTROL OF SOUR GAS PIPELINES

B861 GENERAL

B861.1 Scope

This section contains the minimum additive or substitutive requirements for corrosion control of external and internal corrosion of sour gas piping and components. Where specific provisions are not set forth herein, the provisions of para. 860 of Chapter VI shall apply.

B861.2 Special Considerations

Due to the corrosivity of hydrogen sulfide and the frequent presence of carbon dioxide and salt water, which also are corrosive, special emphasis shall be given to internal corrosion mitigation and monitoring.

Also, due to the corrosive and hazardous nature of the sour gas, special consideration shall be given to the selection of the corrosion allowance.

B862 EXTERNAL CORROSION CONTROL

B862.1 New Installations

B862.11 Buried Steel Facilities

B862.113 Cathodic Protection Requirements. Unless it can be demonstrated by tests or experience that cathodic protection is not needed, all buried or submerged facilities with insulating type coatings, except facilities installed for a limited service life, shall be cathodically protected as soon as feasible following installation, except that minor replacements or extensions shall be protected as covered by para. 862.212.

Facilities installed for a limited service life need not be cathodically protected if it can be demonstrated that the facility will not experience corrosion that will cause it to be harmful to the public or environment. Cathodic protection systems shall be designed to protect the buried or submerged system in its entirety.

A facility is considered to be cathodically protected when it meets one or more of the criteria established in Appendix K.

Use of cathodic protection is encouraged to protect buried sour gas facilities.

B31.8

Interpretation: 12-1

Subject: Paras. 854.1(c) and 854.1(c)(5), Requirements for Class Location Change Study

Date Issued: August 27, 1998

File: B31-98-010

Question (1): If the location class changes from Class 1 to Class 4, is a study required under para. 854.1(c)?

Reply (1): Yes.

Question (2): Are fences and concrete barriers installed along the pipeline within the meaning of "physical barriers" in para. 854.1(c)(5)?

Reply (2): No.

Question (3): Does para. 854.1(c)(5) require a "risk assessment study"?

Reply (3): No. It is up to the owner/operator to determine what types of studies are needed to meet the requirements.

Interpretation: 12-2

Subject: B31G and B31.8-1995 Edition, Para. 841.113(b), Additional Requirements for Nominal Wall Thickness t in Para. 841.11

Date Issued: May 11, 1999

File: B31-95-029

Question (1): Can B31G be used to evaluate pipe based on remaining wall thickness for corrosion that has occurred during the installation stage?

Reply (1): B31G is not applicable to new construction covered under the B31.8 Code.

Question (2): Can para. 841.113(b) be used as criteria for evaluating this corrosion?

Reply (2): No. The B31.8 Section Committee is currently reviewing the Code to determine whether corrosion under the situation you describe should be addressed.

Interpretation: 12-3

Subject: B31.8-1995 Edition, Para. A843.1, Wave and Current Conditions

Date Issued: May 11, 1999

File: B31-98-021

Question (1): Is it practical to determine the most unfavorable expected combination of wave and current conditions?

Reply (1): Yes.

Question (2): If so, how?

Reply (2): The ASME B31.8 Committee is limited strictly to the interpretation of the rules. ASME does not act as a consultant on the general application or on the understanding of the Code rules.

Interpretation: 12-4

Subject: B31.8-1989 Edition, Certification of a Listed Material to Another Listed Specification

Date Issued: August 3, 1999

File: B31-94-048

Question: Does the B31.8 Code address the certification of a listed material to another listed material specification by a service center/processor?

Reply: No.

Interpretation: 12-5

Subject: B31.8-1995 Edition, Para. 842.431(g), Direct Burial

Date Issued: August 3, 1999

File: B31-98-015

Question (1): Is para. 842.431(g) an obligatory requirement for the design execution of 4 bar, direct burial, gas plastic piping systems, in order to comply with the B31.8 Code?

Reply (1): No.

Question (2): In case para. 842.431(g) is obligatory, can DEPA utilize in plastic pipe systems the digital mapping Geographic Information System (GIS) and pipe routing, indicating post marks instead of electronically conductive wire to satisfy the B31.8 Code requirements?

Reply (2): See reply to Question (1) above.

Interpretation: 12-6

Subject: Table 841.114B, Design Factor for Steel Pipe Construction

Date Issued: February 24, 2000

File: B31-99-031

Question (1): Per Table 841.114B, does a gas pipeline (which is covered by B31.8) that skirts a compressor station facility just inside the fence of the facility, but is not associated with the compression process within the facility and exterior to the station emergency shutdown system, need to be designed using a 0.5 or 0.4 design factor?

Reply (1): No.

Question (2): If the answer to Question (1) is no, if the location class allows, and if it is not a fabricated assembly, is a 0.72 design factor acceptable?

Reply (2): Yes.

Question (3): Is a nitrogen gas pipeline covered by the B31.8 Code?

Reply (3): No.

Question (4): If the answer to Question (3) is no, is it because nitrogen is an inert gas and use of B31.8 for the design of nitrogen gas pipeline will be more stringent than necessary?

Reply (4): No.

Interpretation: 12-7

Subject: Para. 841.11(a), Design Factor

Date Issued: January 3, 2001

File: B31-97-058

Question: For pipe produced in accordance with a specification approved in B31.8, can t in the design formula be adjusted above nominal if the wall thickness is guaranteed to be greater than the minimum allowed by the specification?

Reply: No.

Interpretation: 12-8

Subject: Para. 841.11(c)(2)

Date Issued: January 3, 2001

File: B31-99-019

Question: My analysis indicated the AISI constant should be 0.0339 for a full-size specimen. The B31.8 Code constant is 0.0345. Would the B31.8 Section Committee consider reviewing the derivation of this constant in the Code?

Reply: Yes.

Interpretation: 12-9

Subject: Utilization of Duplex Stainless Steel

Date Issued: January 3, 2001

File: B31-95-030

Question: Does B31.8 allow the utilization of duplex stainless steel pipe?

Reply: Yes. Please see paras. 802 and 811.

ASME CODE FOR PRESSURE PIPING, B31

B31.1	Power Piping	2001
B31.2[1]	Fuel Gas Piping	1968
B31.3	Process Piping	1999
B31.4	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids	1998
B31.5	Refrigeration Piping and Heat Transfer Components	2001
B31.8	Gas Transmission and Distribution Piping Systems	1999
B31.9	Building Services Piping	1996
B31.11	Slurry Transportation Piping Systems	1989 (R1998)
B31G-1991	Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B31 Code for Pressure Piping	

NOTE:
(1) USAS B31.2-1968 was withdrawn as an American National Standard on February 18, 1988. ASME will continue to make available USAS B31.2-1968 as a historical document for a period of time.

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