807 KAR 5:022. Gas safety and service.

RELATES TO: KRS 278.485, 278.502
STATUTORY AUTHORITY: KRS 278.280(2)
NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.280(2) provides that the commission shall prescribe rules for the performance of any service or the furnishing of any commodity by any utility. This administrative regulation establishes general rules which apply to gas utilities.

Section 1. General. (1) Definitions. As used in this administrative regulation:
(a) "British thermal unit (BTU)" means quantity of heat that must be added to one (1) pound of pure water to raise its temperature from fifty-eight and one-half (58.5) degrees Fahrenheit to fifty-nine and one-half (59.5) degrees Fahrenheit at the absolute pressure of a column of pure mercury thirty (30) inches high at thirty-two (32) degrees Fahrenheit under standard gravity (32.174 ft. per sec-sec).
(b) "Commission" means the Public Service Commission.
(c) "Cubic foot of gas" means the following:
1. If gas is supplied and metered to customers at standard distribution pressure, a cubic foot of gas shall be defined as that volume of gas which, at the temperature and pressure existing in the meter, occupies one (1) cubic foot.
2. If gas is supplied to customers through turbine, orifice or positive displacement meters at other than standard distribution pressure, a cubic foot of gas shall be defined as that volume of gas which, at sixty (60) degrees Fahrenheit and at absolute pressure of 14.73 pounds per square inch, (thirty (30) inches of mercury), occupies one (1) cubic foot; except that in cases where different bases that are considered by the commission to be fair and reasonable are provided for in gas sales contracts or in rules or practices of a utility, such different bases shall be effective.
3. The standard cubic foot of gas for testing the gas itself for heating value shall be that volume of gas which, when saturated with water vapor and at temperature of sixty (60) degrees Fahrenheit, and under pressure equivalent to that of thirty (30) inches of mercury (mercury at thirty-two (32) degrees Fahrenheit and under standard gravity) occupies one (1) cubic foot.
(d) "Customer piping" means all approved equipment and material required for natural gas service downstream from the property line except for the service tap including saddle (tapping tee) and first service valve and meter (service regulator where required).
(e) "Distribution line" means a pipeline other than a gathering or transmission line.
(f) "Gathering line" means a pipeline that transports gas from a current production facility to a transmission line or main.
(g) "High pressure distribution system" means a distribution system in which gas pressure in the main is higher than pressure provided to the customer.
(h) "Listed specification" means a specification listed in Section 1 of Appendix B of this administrative regulation.
(i) "Low-pressure distribution system" means a distribution system in which gas pressure in the main is substantially the same as pressure provided to the customer.
(j) "Main" means a distribution line that serves as a common source of supply for more than one (1) service line.
(k) "Maximum actual operating pressure" means the maximum pressure that occurs during normal operations over a period of one (1) year.
(l) "Maximum allowable operating pressure (MAOP)" means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this administrative regulation.
(m) "Meter" means any device used to measure the quantity of gas delivered by utility to a customer.
(n) "Operator" means a utility as defined in KRS 278.010.
(o) "Pipe" means any pipe or tubing used in transportation of gas, including pipe-type holders.
(p) "Pipeline" means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.
(q) "Pipeline facility" means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.
(r) "Pressure, absolute" means total gas pressure, which is the sum of barometric pressure plus line gas pressure (gauge), abbreviated as psia.
(s) "Pressure, gauge" means pounds per square inch above atmospheric pressure, abbreviated as psig.

(t) "Secretary" means the Secretary of the U.S. Department of Transportation or any person to whom he has delegated authority.

(u) "Service line" means a distribution line that transports gas from a common source of supply to: customer meter or connection to a customer's piping, whichever is farther downstream; or connection to a customer's piping if there is no customer meter.

(v) "SMYS" means specified minimum yield strength and is defined as:

1. For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

2. For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with Section 3(4)(b) of this administrative regulation.

(w) "State" means Commonwealth of Kentucky.

(x) "Therm" means the unit of heating value equivalent to 100,000 British thermal units.

(y) "Transmission line" means a pipeline, other than a gathering line that:

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

2. Operates at a hoop stress of twenty (20) percent or more of SMYS; or

3. Transports gas within a storage field.

(2) Scope. This administrative regulation prescribes minimum safety and service standards for natural gas utilities operating under the jurisdiction of the commission.

(a) Utilities serving customers under KRS 278.485 or other retail customers, under the jurisdiction of the commission, directly from transmission or gathering lines are exempt from the following sections of this administrative regulation insofar as they apply to these customers:

1. Section 9, subsections (2)(b) through (f), (16) and (17);

2. Section 13, subsections (14), (15), and (16);

3. Section 14, subsection (22);

4. Section 15; and

5. Section 16.

(b) Each utility shall make all reasonable efforts to prevent interruptions of service and if interruptions occur, shall endeavor to reestablish service with the shortest possible delay consistent with the safety of its consumers and the general public. Planned interruptions shall always be preceded by adequate notice to all affected customers.

(3) Class locations.

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

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

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

(d) A Class 3 location is any class location unit that has forty-six (46) or more buildings intended for human occupancy; or an area where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period. (The days and weeks need not be consecutive.)

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

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

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

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

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

(4) Incorporation by reference.

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

(b) All incorporated documents are available for inspection in the offices of the Public Service Commission,

Frankfort, Kentucky. These materials have been approved for incorporation by reference by the Legislative Research Commission. These documents are also available at the addresses provided in Appendix A to this administrative regulation.

(c) Full titles for publications incorporated by reference in this section are provided in Appendix A to this administrative regulation. Numbers in parenthesis indicate applicable editions.

(5) Gathering lines. Each gathering line must comply with requirements of this administrative regulation applicable to transmission lines except as exempted in Section 1(1)(a) of this administrative regulation.

(6) Petroleum gas systems.

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

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

1. Aboveground structures shall have open vents near floor level.

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

3. Relief valve discharge vents shall be located to prevent any accumulation of gas at or below ground level.

4. Special precautions shall be taken to provide adequate ventilation when excavations are made to repair an underground system.

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

(7) General.

(a) No person may operate a pipeline segment readied for service after March 12, 1971, unless:

1. The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this administrative regulation; and

2. The pipeline qualifies for use under this administrative regulation in accordance with Section 1(8) of this administrative regulation.

(b) No person may operate a pipeline segment replaced, relocated, or otherwise changed after November 12, 1970, unless that replacement, relocation, or change has been made in accordance with this administrative regulation.

(c) Each utility shall establish and then maintain plans, procedures and programs as required under this administrative regulation.

(8) Conversion to service subject to this administrative regulation. Steel pipeline previously used in service not subject to this administrative regulation qualifies for use under this administrative regulation if the utility prepares and follows a written procedure to carry out the following requirements:

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

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

3. All known unsafe defects and conditions shall be corrected in accordance with this administrative regulation.

4. The pipeline must be tested in accordance with Section 11 of this administrative regulation to substantiate maximum allowable operating pressure permitted by Section 13 of this administrative regulation.

5. Each utility must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this subsection.

Section 2. Materials. (1) Scope. This section prescribes minimum requirements for selection and qualification of pipe and components for use in pipelines.

(2) General. Materials for pipe and components shall be:

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

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

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

(3) Steel pipe.

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

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

2. It meets the requirements of:

a. Section II of Appendix B to this administrative regulation; or

b. If it was manufactured before November 12, 1970, either Section II or III of Appendix B to this administrative regulation; or

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

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

1. It was manufactured in accordance with a listed specification and it meets the requirements of Section II-C of Appendix B to this administrative regulation;

2. It meets the requirements of:

a. Section II of Appendix B to this administrative regulation;

b. If it was manufactured before November 12, 1970, either Section II or III of Appendix B to this administrative regulation;

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

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

(c) New or used pipe may be used at a pressure resulting in a hoop stress of less than 6,000 psi where no close coiling of close bending is to be done, if visual examination indicates that the pipe is in good condition and is free of split seams and other defects that would cause leakage. If it is to be welded, steel pipe not manufactured to a listed specification shall also pass the weldability tests prescribed in Section II-B of Appendix B to this administrative regulation.

(d) Unused steel pipe manufactured before November 12, 1970, may be used as replacement pipe if it meets the same specifications as the pipe used in constructing that segment of pipeline.

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

(f) New or used pipe of unknown specifications 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 placed in service, and the test pressure used shall establish maximum allowable operating pressure.

(4) Plastic pipe.

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

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

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

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

1. It is manufactured in accordance with a listed specification;

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

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

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

5. It is free of visible defects.

(c) For the purpose of paragraphs (a)1 and (b)1 of this subsection, where pipe of a diameter included in a listed specification is impractical to use, pipe of a diameter between the sizes included in a listed specification may be used if it:

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

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

(5) Marking of materials.

(a) Except as provided in paragraph (d) of this subsection, each valve, fitting, length of pipe, and other components shall be marked as prescribed in:

1. The specification or standard to which it was manufactured; or

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

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

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

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

1. Item is identifiable as to type, manufacturer, and model.

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

(6) Transportation of pipe. In a pipeline to be operated at a hoop stress of twenty (20) percent or more of SMYS, operator shall not use pipe having outer diameter to wall thickness ratio of seventy to one (70 to 1), or more, which is transported by railroad unless:

(a) Transportation is performed in accordance with the most recent edition of API RP5L1, except that before February 25, 1975, transportation may have been performed in accordance with the 1967 edition of API RP5L1.

(b) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with Section 11 of this administrative regulation to at least one and one-fourth (1.25) times maximum allowable operating pressure if it is to be installed in a Class 1 location, and to at least one and one-half (1.5) times maximum allowable operating pressure if it is to be installed in a Class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Section 11 of this administrative regulation, test pressure must be maintained for at least eight (8) hours.

Section 3. Pipe Design. (1) Scope. This section prescribes minimum requirements for design of pipe.

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

(3) Design formula for steel pipe.

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

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

P = Design pressure in pounds per square inch gauge.

S = Yield strength in pounds per square inch determined in accordance with subsection (4) of this section.

D = Nominal outside diameter of pipe in inches.

t = Nominal wall thickness of pipe in inches. If this is unknown, it is determined in accordance with subsection (5) of this section. Additional wall thickness required for concurrent external loads in accordance with subsection (2) of this section shall not be included in computing design pressure.

F = Design factor determined in accordance with subsection (6) of this section.

E = Longitudinal joint factor determined in accordance with subsection (7) of this section.

T = Temperature derating factor determined in accordance with subsection (8) of this section.

(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as part of welding design pressure is limited to seventy-five (75) percent of the pressure determined under paragraph (a) of this subsection if temperature of pipe exceeds 900°F (482°C) at any time or is held above 600°F (316°C) for more than one (1) hour.

(4) Yield strength (s) for steel pipe.

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

(b) For pipe manufactured in accordance with a specification not listed in Section I of Appendix B to this administrative regulation or whose specification or tensile properties are unknown, yield strength to be used in the design formula in subsection (3) of this section is one of the following:

1. If pipe is tensile tested in accordance with Section II-D of Appendix B to this administrative regulation, the lower of the following:

a. Eighty (80) percent of average yield strength determined by tensile tests; or

b. The lowest yield strength determined by tensile tests, but no more than 52,000 psig.

2. If pipe is not tensile tested as provided in paragraph (b)1 of this subsection, 24,000 psig.

(5) Nominal wall thickness (t) for steel pipe.

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

(b) However, if pipe is of uniform grade, size and thickness and there are more than ten (10) lengths, only ten (10) percent of the individual lengths, but not less than ten (10) lengths, need be measured. Thickness of lengths not measured shall be verified by applying a gauge set to the minimum thickness found by measurement. Nominal wall thickness to be used in the design formula in subsection (3) of this section is the next wall thickness found in commercial specifications that is below the average of all measurements taken. However, nominal wall thickness used shall not be more than 1.14 times the smallest measurement taken on pipe less than twenty (20) inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe twenty (20) inches or more in outside diameter.

(6) Design factor (F) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this subsection, the design factor to be used in the design formula in subsection (3) of this section is determined in accordance with the following table:

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

(b) A design factor of six-tenths (0.60) or less shall be used in the design formula in subsection (3) of this section, for steel pipe in Class 1 locations that:

1. Cross the right-of-way of an unimproved public road, without a casing;

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

3. Are supported by a vehicular, pedestrian, railroad, or pipeline bridge; or

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

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

(d) For Class 1 and Class 2 locations, a design factor of five-tenths (0.50) or less shall be used in the design formula in subsection (3) of this section for:

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

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

(7) Longitudinal joint factor (E) for steel pipe. Longitudinal joint factor to be used in the design formula in subsection (3) of this section is determined in accordance with the following table:

Specification	Pipe Class	Longitudinal Joint Factor (E)
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 333	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric fusion welded	1.00
ASTM A 672	Electric fusion welded	1.00
ASTM A 691	Electric fusion welded	1.00
API 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
Other	Pipe over 4 inches	.80
Other	Pipe 4 inches or less	.60

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

(8) Temperature derating factor (T) for steel pipe. Temperature derating factor to be used in the design formula in subsection (3) of this section is determined as follows:

Gas temperature in degrees Fahrenheit	Temperature derating factor (T)
250 or less	1.000
300	0.967
350	0.933

400	0.900
450	0.867

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

(9) Design of plastic pipe. Design pressure for plastic pipe is determined in accordance with the following formula, subject to the limitations of subsection (10) of this section:

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

P = Design pressure, gauge, kPa (psi).

S = For thermoplastic pipe the long-term hydrostatic strength determined in accordance with the listed specification at a temperature equal to twenty-three (23) degrees Centigrade (seventy-three (73) degrees Fahrenheit), thirty-eight (38) degrees Centigrade (100 degrees Fahrenheit), forty-nine (49) degrees Centigrade (120 degrees Fahrenheit), or sixty (60) degrees Centigrade (140 degrees Fahrenheit): for reinforced thermosetting plastic pipe, 75,800 kPa (11,000 psig).

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

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

(10) Design limitations for plastic pipe.

(a) Design pressure shall not exceed gauge pressure of 689 kPa (100 psig) for plastic pipe used in:

1. Distribution systems; or

2. Classes 3 and 4 locations.

(b) Plastic pipe shall not be used where operating temperature of pipe will be:

1. Below minus twenty-nine (29) degrees Centigrade (minus twenty (20) degrees Fahrenheit); or

2. In the case of thermoplastic pipe, above the temperature at which the long-term hydrostatic strength used in the design formula under subsection (9) of this section is determined, except that pipe manufactured before May 18, 1978, may be used at temperatures up to thirty-eight (38) degrees Centigrade (100°F); or in the case of reinforced thermosetting plastic pipe, above sixty-six (66) degrees Centigrade (150°F).

(c) Wall thickness for thermoplastic pipe shall not be less than 1.57 millimeters (0.062 in.).

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

Nominal size in inches:	Minimum wall thickness millimeters (inches)
2	1.52 (0.060)
3	1.52 (0.060)
4	1.78 (0.070)
5	2.54 (0.100)

(11) Design of copper pipe.

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

(b) Copper pipe used in service lines shall have a wall thickness not less than that indicated in the following table:

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

(c) Copper pipe used in mains and service lines shall not be used at pressures in excess of 100 psig.

(d) Copper pipe that does not have an internal corrosion resistant lining shall not be used to carry gas that has an average hydrogen sulfide content of more than three-tenths (0.3) grains per 100 standard cubic feet of gas.

Section 4. Design of Pipeline Components. (1) Scope. This section prescribes minimum requirements for design and installation of pipeline components and facilities, and it prescribes requirements relating to protection against accidental overpressuring.

(2) General requirements. Each component of a pipeline shall withstand operating pressures and other anticipated loadings without impairment of serviceability with unit stresses equivalent to those allowed for

comparable material in pipe in the same location and kind of service. However, if design based upon unit stress is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(3) Qualifying metallic components. Notwithstanding any requirement of this section which incorporates by reference an edition of a document listed in Appendix A of this administrative regulation, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this administrative regulation if:

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

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

1. Pressure testing;

2. Materials; and

3. Pressure and temperature ratings.

(4) Valves.

(a) Except for cast iron and plastic valves, each valve shall meet the minimum requirements, or equivalent, of API 6D. A valve shall not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.

(b) Each cast iron and plastic valve shall comply with the following:

1. The valve shall have a maximum service pressure rating for temperatures that equal or exceed maximum service temperature.

2. The valve shall be tested as part of the manufacturing, as follows:

a. With the valve fully open, the shell shall be tested with no leakage to a pressure at least one and one-half (1.5) times the maximum service rating.

b. After the shell test, the seat shall be tested to a pressure not less than one and one-half (1.5) times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test shall be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.

c. After the last pressure test is completed, the valve shall be operated through its full travel to demonstrate freedom from interference.

(c) Each valve shall be able to meet anticipated operating conditions.

(d) No valve having shell components made of ductile iron may be used at pressures exceeding eighty (80) percent of pressure ratings for comparable steel valves at their listed temperatures. However, a valve having shell components made of ductile iron may be used at pressures up to eighty (80) percent of pressure ratings for comparable steel valves at their listed temperatures, if:

1. Temperature-adjusted service pressure does not exceed 1,000 psig; and

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

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

(5) Flanges and flange accessories.

(a) Each flange or flange accessory (other than cast iron) shall meet the minimum requirements of ANSI B16.5, MSS SP-44, or equivalent.

(b) Each flange assembly shall withstand the maximum pressure at which the pipeline is to be operated and maintain its physical and chemical properties at any anticipated temperature.

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

(6) Standard fittings.

(a) Minimum metal thickness of threaded fittings shall not be less than specified for pressures and temperatures in applicable standards referenced in this administrative regulation, or their equivalent.

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

(7) Tapping.

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

(b) Where ductile iron pipe is tapped, the extent of full-threaded engagement and need for use of outside-sealing

service connections, tapping saddles, or other fixtures shall be determined by service conditions.

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

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

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

However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on six (6) inch or larger pipes.

(8) Components fabricated by welding.

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, design pressure of each component fabricated by welding, whose strength cannot be determined, shall be established in accordance with paragraph UG-101 of Section VIII of the ASME Boiler and Pressure Vessel Code.

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

1. Regularly manufactured butt-welding fittings.

2. Pipe produced and tested under a specification listed in Appendix B to this administrative regulation.

3. Partial assemblies such as split rings or collars.

4. Prefabricated units that the manufacturer certifies have been tested to at least twice the anticipated maximum pressure under operating conditions.

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

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

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

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

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

(12) Supports and anchors.

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

1. Prevent undue strain on connected equipment;

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

3. Prevent or damp out excessive vibration.

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

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

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

2. Provision shall be made for service conditions involved.

3. Movement of the pipeline shall not cause disengagement of support equipment.

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

1. A structural support shall not be welded directly to the pipe.

2. The support shall be provided by a member that completely encircles the pipe.

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

(e) Each underground pipeline connected to a relatively unyielding line or other fixed object shall have enough flexibility to provide for possible movement, or it shall have an anchor that will limit movement of the pipeline.

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

(13) Compressor stations: design and construction.

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

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

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

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

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

(d) Fenced areas. Each fence around a compressor station shall have at least two (2) gates located to provide convenient opportunity for escape to safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet of any compressor plant building shall open outward and, when occupied, shall be of a type that can be readily opened from inside without a key.

(e) Electrical areas. Electrical equipment and wiring installed in compressor stations shall conform to the National Electrical Code, NFPA-70(ANSI), so far as that code is applicable.

(f) Air piping system.

1. All air piping within gas compressing stations shall be constructed in accordance with Section 2 of the USAS B31.1 Code for Pressure Piping.

2. Starting air pressure, storage volume and size of connection piping shall be adequate to rotate the engine at cranking speed and for the number of revolutions necessary to purge fuel gas from the power cylinder and muffler. Recommendations of the engine manufacturer may be used as a guide in determining these factors. Consideration should be given to the number of engines installed and to the possibility of starting several of these engines within a short period of time.

3. A check valve shall be installed in the starting air line near each engine to prevent backflow from the engine into the piping system. A check valve shall also be placed in the main air line on the immediate outlet side of the air tank or tanks. It is recommended that equipment for cooling air and removing moisture and entrained oil be installed between the starting air compressor and air storage tanks.

4. Suitable provision shall be made to prevent starting air from entering power cylinders of an engine and activating moving parts while work is in progress on the engine or on equipment driven by the engines. Acceptable means of accomplishing this are installation of a blind flange, removal of a portion of the air supply piping or locking closed a stop valve and locking open a vent downstream from it.

(g) Air receivers. Air receivers or air storage bottles, for use in compressor stations, shall be constructed and equipped in accordance with Section VII, Unfired Pressure Vessels, of the ASME Boiler and Pressure Vessel Code.

(h) Lubricating oil piping. All lubricating oil piping with gas compressing stations shall be constructed in accordance with USA Standard Code for Pressure Piping, Petroleum Refinery Piping, USAS B 31.3.

(i) Water and steam piping. All water and steam piping within gas compressing stations shall be constructed in accordance with USA Standard Code for Pressure Piping, Power Piping, USAS B31.0.0.

(j) Hydraulic piping. All hydraulic power piping within gas compressing stations shall be constructed in accordance with USA Standard Code for Pressure Piping, Petroleum Refinery Piping, USAS B31.3.

(14) Compressor stations; liquid removal.

(a) Where entrained vapors in gas may liquefy under anticipated pressure and temperature conditions, the compressor shall be protected against introduction of those liquids in damaging quantities.

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

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

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

3. Be manufactured in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code, except that liquid separators constructed of pipe and fittings without internal welding shall be fabricated with a design factor of four-tenths (0.4) or less.

(15) Compressor stations: emergency shutdowns.

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

1. Block gas out of the station and blow down the station piping.

2. Discharge gas from the blowdown piping at a location where gas will not create a hazard.

3. Provide means for shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except, that:

a. Electric circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers shall remain energized; and

b. Electrical circuits needed to protect equipment from damage may remain energized.

4. It shall be operable from at least two (2) locations, each of which is:

a. Outside the gas area of the station;

b. Near the exit gates, if station is fenced; or near emergency exits, if not fenced; and

c. Not more than 500 feet from the limits of the stations.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system shall be designed to prevent function at the wrong time and unintended outage on the distribution system.

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

1. In the case of an unattended compressor station:

a. When gas pressure equals maximum allowable operating pressure plus fifteen (15) percent; or

b. When uncontrolled fire occurs on the platform; and

2. In the case of a compressor station in a building:

a. When uncontrolled fire occurs in the building; or

b. When the concentration of gas in air reaches fifty (50) percent or more of the lower explosive limit in a building which has a source of ignition.

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

3. All emergency valves and controls shall be identified by signs. All important gas pressure piping shall be identified by signs or color codes as to their function.

(16) Compressor stations: pressure limiting devices.

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

(b) Each vent line that exhausts gas from the pressure relief valve of a compressor station shall extend to a location where gas may be discharged without hazard.

(17) Compressor stations: additional safety equipment.

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

(b) Each compressor station prime mover, other than an electrical induction or synchronous motor, shall have an automatic device to shut down the unit before the speed of either the prime mover or driven unit exceeds maximum safe speed.

(c) Each compressor unit in a compressor station shall have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.

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

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

(f) Fuel gas lines within a compressor station, serving various buildings and residential areas, shall be provided with master shutoff valves located outside of any building or residential area.

(18) Compressor stations: ventilation. Each compressor station building shall be ventilated to ensure that employees are not endangered by accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

(19) Pipe-type and bottle-type holders.

(a) Each pipe-type and bottle-type holder shall be designed to prevent accumulation of liquids in the holder, connecting pipe, or auxiliary equipment, that might cause corrosion or interfere with safe operation of the holder.

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

$$C = (D \times P \times F)/1{,}000$$

in which:

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

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

P = Maximum allowable operating pressure, psig.

F = Design factor as set forth in Section 3(6) of this administrative regulation.

(20) Additional provisions for bottle-type holders.

(a) Each bottle-type holder shall be:

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

Maximum allowable operating pressure	Minimum clearance (feet)
Less than 1,000 psig	25
1,000 psig or more	100

2. Designed using the design factors set forth in Section 3(6) of this administrative regulation; and

3. Buried with minimum cover in accordance with Section 7(13) of this administrative regulation.

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

1. A bottle-type holder made from alloy steel shall meet the chemical and tensile requirements for various grades of steel in ASTM A 372.

2. Actual yield-tensile ratio of steel shall not exceed 0.85.

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

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

5. The holder, connection pipe, and components shall be leak tested after installation as required by Section 11 of this administrative regulation.

(21) Transmission line valves.

(a) Each transmission line shall have sectionalizing block valves spaced as follows:

1. Each point on the pipeline in a Class 4 location shall be within two and one-half (2 1/2) miles of a valve.

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

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

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

(b) Each sectionalizing block valve on a transmission line shall comply with the following:

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

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

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

(22) Distribution line valves.

(a) Each high-pressure distribution system shall have valves spaced to reduce the time to shut down a section of main in an emergency. Valve spacing is determined by operating pressure, size of mains, and local physical conditions.

(b) Each valve on a main installed for operating or emergency purposes shall be placed in a readily accessible location to facilitate its operation in an emergency, and its operating stem or mechanism shall be readily accessible. If the valve is installed in a buried box or enclosure, the box or enclosure shall be installed to avoid transmitting external loads to the main.

(23) Valves at regulator stations.

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

(b) Exterior shutoff valves shall be installed on all lines entering and leaving regulator stations for use in an emergency to stop gas flow. Such valves shall be installed at an accessible location where they can be operated in

an emergency.

1. Exterior shutoff valves shall be located a minimum of forty (40) feet from the regulator station if inlet pressure to the station is 100 psig or less. Valves shall be located a minimum of 100 feet from the regulator station if inlet pressure is more than 100 psig.

2. A check valve may be used in lieu of an exterior shutoff valve on downstream piping if located a minimum of forty (40) feet from the regulator station.

3. The exterior shutoff valve may be a sectionalizing valve.

4. All exterior shutoff valves shall be inspected and partially operated at least once each calendar year at intervals not to exceed fifteen (15) months.

(24) Vaults: structural design requirements.

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

(b) There shall be enough working space so that all equipment required in the vault or pit can be properly installed, operated, and maintained.

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

(d) Vault or pit openings shall be located to minimize hazards of tools or other objects falling upon the regulator, piping or other equipment. The control piping and operating parts of equipment installed shall not be located under a vault or pit opening where workmen can step on them when entering or leaving the vault or pit, unless such parts are suitably protected.

(e) Whenever a vault or pit opening is to be located above equipment which could be damaged by a falling cover, a circular cover shall be installed or other suitable precautions taken.

(25) Vaults: accessibility. Each vault shall be located in an accessible location, so far as practical, away from:

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

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

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

(26) Vaults: sealing, venting, and ventilation. Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, shall be sealed, vented or ventilated, as follows:

(a) When internal volume exceeds 200 cubic feet:

1. The vault or pit shall be ventilated with two (2) ducts, each having at least the ventilating effect of a pipe four (4) inches in diameter;

2. Ventilation shall be enough to minimize formation of combustible atmosphere in the vault or pit; and

3. Ducts shall be high enough above grade to disperse any gas-air mixtures that might be discharged.

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

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

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

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

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

(27) Vaults: drainage and waterproofing.

(a) Each vault shall be designed to minimize entrance of water.

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

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

(28) Design pressure of plastic fittings.

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

(b) Thermoplastic fittings for plastic pipe shall conform to ASTM D 2513.

(29) Valve installation in plastic pipe. Each valve installation in plastic pipe shall be designed to protect plastic

material against excessive torsional or shearing loads when the valve or shutoff is operated, and from any other secondary stresses that might be exerted through the valve or its enclosures.

(30) Protection against accidental overpressuring:

(a) General requirements. Except as provided in subsection (31) of this section, each pipeline connected to a gas source so that maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, shall have pressure relieving or pressure limiting devices that meet the requirements of subsections (32) and (33) of this section.

(b) Additional requirements for distribution systems. Each distribution system supplied from a source of gas at higher pressure than maximum allowable operating pressure for the system shall:

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

2. Be designed to prevent accidental overpressuring.

(31) Control of pressure of gas delivered from high-pressure distribution systems.

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

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

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

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

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

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

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

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

(c) If maximum actual operating pressure of the distribution system exceeds sixty (60) psig, one (1) of the following methods shall be used to regulate and limit, to maximum safe value, the pressure of gas delivered to the customer:

1. A service regulator having the characteristics listed in paragraph (a) of this subsection, and another regulator located upstream from the service regulator. The upstream regulator shall not be set to maintain a pressure higher than sixty (60) psig. A device shall be installed between the upstream regulator and the service regulator to limit pressure on the inlet of the service regulator to sixty (60) psig or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff that shuts, if pressure on the inlet of the service regulator exceeds the set pressure (sixty (60) psig or less), and remains closed until manually reset.

2. A service regulator and a monitoring regulator set to limit, to a maximum safe value, pressure of gas delivered to the customer.

3. A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and shall not be used where inlet pressure on the service regulator exceeds 125 psig. For higher inlet pressure, the methods in paragraph (c)1 or 2 of this subsection shall be used.

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

(32) Requirements for design of pressure relief and limiting devices. Except for rupture discs, each pressure relief or pressure limiting device shall:

(a) Be constructed of materials to prevent operation impairment by corrosion;

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

(c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine operational pressure and can be tested for leakage when closed;

(d) Have support made of noncombustible material;

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

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

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

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

(33) Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect pipeline shall have enough capacity, and shall be set to operate, to insure the following:

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

2. In pipelines other than a low pressure distribution system:

a. If maximum allowable operating pressure is sixty (60) psig or more, pressure shall not exceed maximum allowable operating pressure plus ten (10) percent, or the pressure that produces hoop stress of seventy-five (75) percent of SMYS, whichever is lower.

b. If maximum allowable operating pressure is twelve (12) psig or more, but less than sixty (60) psig, pressure shall not exceed maximum allowable operating pressure plus six (6) psig; or

c. If maximum allowable pressure is less than twelve (12) psig, pressure shall not exceed maximum allowable operating pressure plus fifty (50) percent.

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

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

(34) Instrument, control and sampling pipe and components.

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

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

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

2. A shutoff valve shall be installed in each takeoff line as near as practicable to point of takeoff. Blowdown valves shall be installed where necessary.

3. Brass or copper material shall not be used for metal temperatures greater than 400 degrees Fahrenheit.

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

5. Pipe or components in which liquids may accumulate shall have drains or drips.

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

7. Arrangement of pipe, components, and supports shall provide safety under anticipated operating stresses.

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

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

Section 5. Welding of Steel in Pipelines. (1) Scope.

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

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

(2) Qualification of welding procedures.

(a) Welding shall be performed by a qualified welder in accordance with established, written, and tested welding procedures; and quality of test welds determined by destructive testing to meet acceptability standards of this section.

(b) Each welding procedure shall be recorded in detail, including results of qualifying tests. This record shall be retained and followed whenever the procedure is used.

(3) Qualification of welders.

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

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

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

2. Within the preceding seven and one-half (7 1/2) calendar months, but at least twice each calendar year, the welder has had:

a. A production weld cut out, tested and found acceptable in accordance with the qualifying test; or

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

(4) Limitations on welders.

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

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

(c) A welder qualified under subsection (3)(a) of this section shall not weld unless, within the preceding six (6) calendar months, the welder has had one (1) weld tested and found acceptable under Section 3 or 6 of API Standard 1104, except that a welder qualified under an earlier edition previously listed in Appendix A may weld but shall not requalify under that earlier edition.

(5) Protection from weather. The welding operation shall be protected from weather conditions that would impair the quality of the completed weld.

(6) Miter joints.

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

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

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

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

(8) Inspection and test of welds.

(a) Visual inspection of welding shall be conducted to insure that:

1. Welding is performed in accordance with welding procedure; and

2. Weld is acceptable under paragraph (c) of this subsection.

(b) Welds on a pipeline to be operated at pressure that produces hoop stress of twenty (20) percent or more of SMYS shall be nondestructively tested in accordance with subsection (9) of this section, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if:

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

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

(c) Acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 6 of API Standard 1104.

(9) Nondestructive testing.

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

(b) Nondestructive testing of welds shall be performed:

1. In accordance with written procedures; and

2. By persons trained and qualified in established procedures and with equipment employed in testing.

(c) Procedures shall be established for proper interpretation of each nondestructive test of a weld to ensure acceptability of the weld under subsection (8)(c) of this section.

(d) When nondestructive testing is required under subsection (8)(b) of this section, the following percentages of each day's field butt welds, selected at random by the operator, shall be nondestructively tested over their entire circumference:

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

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

3. In Class 3 and Class 4 locations, at crossings of major or navigable rivers, and offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, then at least ninety (90) percent. Nondestructive testing shall be impracticable for each girth weld not tested.

4. At pipeline tie-ins 100 percent.

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day shall be nondestructively tested, when nondestructive testing is required under subsection (8)(b) of this section.

(f) When nondestructive testing is required under subsection (8)(b) of this section, each operator shall retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, number nondestructively tested, number rejected, and disposition of rejects.

(10) Repair or removal of defects.

(a) Each weld that is unacceptable under subsection (8)(c) of this section shall be removed or repaired. A weld shall be removed if it has a crack that is more than eight (8) percent of the weld length.

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

(c) Repair of a crack or any defect in a previously repaired area shall be in accordance with written weld repair procedures qualified under subsection (2) of this section. Repair procedures shall provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

Section 6. Joining of Materials other than by Welding. (1) Scope.

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

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

(2) General.

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

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

(c) Each joint shall be inspected to insure compliance with this subsection.

(3) Cast iron pipe.

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

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

(c) Cast iron pipe shall not be joined by threaded joints or by brazing.

(4) Ductile iron pipe. Ductile iron pipe shall not be jointed by threaded joints or by brazing.

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

(6) Plastic pipe.

(a) General. A plastic pipe joint joined by solvent cement, adhesive, or heat fusion shall not be disturbed until it has properly set. Plastic pipe shall not be joined by a threaded joint or miter joint.

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

1. Mating surfaces of the joint shall be clean, dry, and free of material which might be detrimental to the joint.

2. Solvent cement shall conform with ASTM Specification D 2513.

3. Joint shall not be heated to accelerate setting of the cement.

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

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

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

3. Heat shall not be applied with a torch or other open flame.

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

1. Adhesive shall conform to ASTM Specification D 2517.

2. Materials and adhesive shall be compatible with each other.

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

1. Gasket material in the coupling shall be compatible with the plastic.

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

(7) Plastic pipe; qualifying joining procedures.

(a) Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under subsection (2)(b) of this section is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, that procedure shall be qualified by subjecting specimen joints made according to the procedure to the following tests:

1. Burst test requirements of:

a. If thermoplastic pipe, Paragraph 8.6 (Sustained Pressure Test) or Paragraph 8.7 (Minimum Hydrostatic Burst Pressure) of ASTM D 2513; or

b. If thermosetting plastic pipe, Paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or Paragraph 8.9 (Sustained Static Pressure Test) of ASTM D 2517;

2. For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use; and

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

(b) Mechanical joints. Before any written procedure established under subsection (2)(b) of this section is used for making mechanical plastic pipe joints designed to withstand tensile forces, the procedure shall be qualified by subjecting five (5) specimen joints made according to the procedure to the following tensile test:

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

2. Specimen shall be of such length that distance between the grips of the apparatus and the end of the stiffener does not affect joint strength.

3. Speed of testing is five (5) millimeters (two-tenths (.20) inches) per minute, plus or minus twenty-five (25) percent.

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

5. Pipe specimens 102 millimeters (four (4) inches) and larger in diameter shall be pulled until the pipe is subjected to tensile stress equal to or greater than maximum thermal stress that would be produced by a temperature change of fifty-five (55) degrees Centigrade (100°F) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five (5) test results or the manufacturer's rating, whichever is lower, shall be used in design calculations for stress.

6. Each specimen that fails at the grips shall be retested using new pipe.

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

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

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

(8) Plastic pipe; qualifying persons to make joints.

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

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

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

(b) Specimen joint shall be:

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

2. If a heat fusion, solvent cement, or adhesive joint:

a. Tested under any one (1) of the test methods listed in subsection (7)(a) of this section applicable to the type of joint and material being tested;

b. Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

c. Cut into at least three (3) longitudinal straps, each of which is:

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

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

(iii) A person shall be requalified under an applicable procedure, if during any twelve (12) month period that person:

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

B. Has made three (3) joints or three (3) percent of the joints, whichever is greater, under that procedure, that are found unacceptable by testing under Section 11(7) of this administrative regulation.

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

(9) Plastic pipe; inspection of joints. No person shall carry out the inspection of joints in plastic pipes required by subsections (2)(c) and (8)(b) of this section unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.

Section 7. General Construction Requirements for Transmission Lines and Mains. (1) Scope. This section prescribes minimum requirements for constructing transmission lines and mains.

(2) Compliance with specifications or standards. Each transmission line or main shall be constructed in accordance with comprehensive written specifications or standards consistent with this section.

(3) Reports and records of proposed construction:

(a) At least thirty (30) days prior to construction or major reconstruction of any gas pipeline intended to be subjected to pressure in excess of 100 psig, or twenty (20) percent of minimum yield strength, whichever is lower, and after receipt from the commission of a certificate of public convenience and necessity for such construction if required, the utility shall file a report with the commission setting forth the specifications for such pipeline and the maximum allowable operating pressure.

(b) Before any gas pipeline or main is placed in operation intended to be subjected to pressures in excess of 100 psig, or twenty (20) percent of specified minimum yield strength, whichever is lower, a report shall be filed with the commission certifying the maximum pressure to which the line is intended to be subject and also certifying that the pipeline has been constructed and testing in accordance with the requirements of this administrative regulation. A further report shall be filed within sixty (60) days thereafter including the results of all tests made pursuant to this section. No gas pipeline or main shall be operated at pressures in excess of the pressure for which it was certified to the commission.

(d) Responsibility for maintenance of necessary records to establish that compliance with rules and administrative regulations has been accomplished rests with the utility. Such records shall be available for inspection at all times by commission staff.

(4) Inspection: general. Each transmission line or main shall be inspected to ensure that it is constructed in accordance with this section. The inspector shall have authority to order removal and replacement of any section of pipe and fittings that fail to meet the standards of this administrative regulation.

(5) Inspection of materials. Each length of pipe and each other component shall be visually inspected at site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability. Plastic pipe and tubing shall be adequately supported during storage. Thermoplastic pipe, tubing and fittings shall be protected from exposure to direct sun rays if the pipe is to remain exposed for twelve (12) months or longer unless written warranty of the manufacturer states that such protection is not necessary. However, if the manufacturer specifies that the pipe has been manufactured with a minimum of two (2) percent or more carbon black content to prevent ultraviolet degradation, the pipe may be exposed to sun rays for up to thirty-six (36) months.

(6) Repair of steel pipe.

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

1. Minimum thickness required by the tolerance in the specification to which the pipe was manufactured; or

2. Nominal wall thickness required for the design pressure of the pipeline.

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

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

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

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

a. More than one-quarter (1/4) inch in pipe twelve and three-fourths (12 3/4) inches or less in outer diameter; or

b. More than two (2) percent of the nominal pipe diameter in pipe over twelve and three-fourths (12 3/4) inches is outer diameter.

For purposes of this subsection a "dent" is a depression that produces gross disturbance in curvature of the pipe wall without reducing pipe-wall thickness. Depth of a dent is measured as the gap between the lowest point of the dent and a promulgation of the pipe's original contour.

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

1. Minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or

2. Nominal wall thickness required for the design pressure of the pipeline.

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

(e) Each gouge, groove, arc burn, or dent removed from a length of pipe shall be removed by cutting out the damaged portion as a cylinder.

(7) Repair of plastic pipe. Each imperfection or damage that would impair serviceability of plastic pipe shall be repaired by a patching saddle or removed.

(8) Bends and elbows.

(a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with subsection (9) of this section shall comply with the following:

1. A bend shall not impair serviceability of the pipe.

2. Each bend shall have a smooth contour and be free from buckling, cracks, or any other mechanical damage.

3. On pipe containing a longitudinal weld, the longitudinal weld shall be as near as practicable to the neutral axis of the bend unless:

a. The bend is made with an internal bending mandrel; or

b. The pipe is twelve (12) inches or less in outside diameter or has a diameter to wall thickness ratio less than seventy (70).

(b) Each circumferential weld of steel pipe located where stress during bending caused permanent deformation in the pipe shall be nondestructively tested either before or after the bending process.

(c) Wrought-steel welding elbows and transverse segments of these elbows shall not be used for changes in direction on steel pipe two (2) inches or more in diameter unless the arc length, as measured along the crotch, is at least one (1) inch.

(9) Wrinkle bends in steel pipe.

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

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

1. The bend shall not have any sharp kinks.

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

3. On pipe sixteen (16) inches or larger in diameter, the bend shall not have a deflection of more than one and

one-half (1 1/2) degrees for each wrinkle.

4. On pipe containing a longitudinal weld, the longitudinal seam shall be as near as practicable to the neutral axis of the bend.

(10) Protection from hazards.

(a) Each transmission line or main shall be protected from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads.

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

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

(11) Installation of pipe in a ditch.

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

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

1. Provides firm support under the pipe; and

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

(12) Installation of plastic main.

(a) Plastic pipe shall be installed below ground level and shall conform to applicable provisions of subsection (15) of this section except that plastic mains shall be installed with minimum cover of twenty-four (24) inches at all stress levels unless encased or otherwise protected.

(b) Plastic pipe installed in a vault or any other below grade enclosure shall be completely encased in gastight metal pipe and fittings adequately protected from corrosion.

(c) Plastic pipe shall be installed to minimize shear or tensile stresses.

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

(e) Plastic pipe not encased shall have an electrically conductive wire or other means of located the pipe while it is underground.

(f) Plastic pipe being encased shall be inserted into casing pipe in a manner that will protect the plastic. The leading end of the plastic shall be closed before insertion.

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

(a) Casing shall be designed to withstand superimposed loads.

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

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

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

(14) Underground clearance.

(a) Each transmission line shall be installed with at least twelve (12) inches of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, The transmission line shall be protected from damage that might result from proximity to other structures.

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

(c) In addition to meeting the requirements of paragraph (a) or (b) of this subsection, each plastic transmission line or main shall be installed with sufficient clearance, or shall be insulated, from any source of heat to prevent heat from impairing serviceability of the pipe.

(d) Each pipe-type or bottle type holder shall be installed with minimum clearance from any other holder as prescribed in Section 4(19)(b) of this administrative regulation.

(15) Cover.

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

Location	Normal Soil (inches)	Consolidated Rock (inches)

Class 1 locations	30	18
Class 2, 3 and 4 locations	36	24
Drainage ditches of public roads and railroad crossings	36	24

(b) Except as provided in paragraphs (c) and (d) of this subsection, each buried main shall be installed with at least twenty-four (24) inches of cover.

(c) Where an underground structure prevents installation of a transmission line or main with minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) All pipe installed in a navigable river or stream shall have minimum cover of forty-eight (48) inches in soil or twenty-four (24) inches in consolidated rock. However, less than minimum cover is permitted in accordance with paragraph (c) of this subsection.

Section 8. Gas Measurement. (1) Scope. This section prescribes minimum requirements for measurement of gas, accuracy of measuring instruments (meters), meter testing facilities and periodic testing of meters.

(2) Method of measuring service.

(a) All gas sold by a utility and all gas consumed by a utility in the State of Kentucky shall be metered through approved type meters except in cases of emergency or when otherwise authorized by the commission. Each meter shall bear an identifying number. When gas is sold at high pressures or large volumes, the contract or rate schedule shall specify standards used to calculate gas volume. Prepayment meters shall not be used unless there is no other satisfactory method of collecting payment for services rendered.

(b) All gas delivered as compensation for leases, rights-of-way, or for other reasons, not charged at the utility's regular schedule of charges, shall be metered and a record kept of each transaction. All meters and regulators installed to measure gas and to regulate pressure of gas shall be under the control of the utility and subject to the rules of the utility and of the commission.

(c) The utility shall make no charge for furnishing and installing any meter or appurtenance necessary to measure gas furnished, except by mutual agreement as approved by the commission in special cases or except where duplicate or check meters are requested by the customer.

(d) Each gas utility shall adopt a standard method of meter and service line installation insofar as practicable. These methods shall be set out with a written description and with drawings as necessary for clear understanding of the requirements, all of which shall be filed with the commission. Copies of these standard methods shall be made available to prospective customers, contractors or others engaged in installing pipe for gas utilization. All meters shall be set in place by the utility.

(e) Each customer shall be metered separately except in cases of multioccupants under the same roof sharing a common entrance or an enclosure where it is unreasonable or uneconomical to measure each unit separately.

(f) The utility may render temporary service to a customer and may require the customer to bear all costs of installing and removing service in excess of any salvage realized. In this respect, temporary service shall be considered to be service that is not required or used for more than one (1) year.

(3) Accuracy requirements for meters. All tests to determine accuracy of registration of any gas meters shall be made by a qualified meter tester and with suitable facilities.

(a) Diaphragm displacement meters:

1. Before being installed for use by any customer, every diaphragm displacement gas meter, whether new, repaired or removed from service for any cause shall be in good working condition and shall be adjusted to be correct to within one-half (1/2) of one (1) percent, plus or minus when passing gas at approximately twenty (20) percent and 100 percent of the rated capacity of the meter as specified by the manufacturer based on five-tenths (0.5) inch water column differential. A pilot test or quartering test to determine that the meter will register at one-half (1/2) of one (1) percent of the rated capacity shall be made before placing meters in service.

2. Meters removed from service for periodic testing shall be tested for accuracy as soon as practical after removal. An "as found" test shall be made at a flow-rate of approximately twenty (20) percent and 100 percent of the rated capacity of the meter based on five-tenths (0.5) inch water column differential and results of these tests algebraically averaged to determine accuracy. If error is less than two (2) percent this shall be reported as the "as found" test. If error is more than two (2) percent, two (2) additional tests shall be made at twenty (20) percent and 100 percent, and the average of these three (3) tests shall be reported as the "as found" test. The three (3) test procedures shall apply to any customer request test, complaint test, or bill adjustment made on the basis of the meter.

3. Meters of good working condition that are removed from service for reasons other than periodic, customer or

commission request tests shall be tested as soon as practicable after removal if elapsed time since the last test exceeds fifty (50) percent of the periodic test period for those meters.

(b) Other than diaphragm displacement meters.

1. All meters other than diaphragm displacement meters shall be tested at approved intervals by the utility meter tester using flow provers or other approved methods either in the shop or at the location of use at the utility's option and with the commission's approval of facilities and methods used. Accuracy of these meters shall be maintained as near 100 percent as possible. Test ranges and procedures shall be as prescribed in adopted standards or approved by the commission.

2. All meter installations shall be inspected for proper design and construction and all instruments, regulators and valves used in conjunction with installation shall be tested for desired operation and accuracy before being placed in service. This inspection shall be made by a qualified person. Test data as to conditions found, corrected if in error, and conditions as left shall be made available for inspection by commission staff. Subsequent test results shall be a portion of regular meter test reports submitted to the commission by the utility.

(4) Meter testing facilities and equipment.

(a) Meter shop.

1. Each utility, unless specifically excepted by the commission, shall maintain a meter shop to inspect, test and repair meters. The shop shall be open for inspection by commission staff at all reasonable times. Facilities and equipment, as well as methods of measurement and testing employed, shall be subject to approval of the commission.

2. The meter shop shall consist of a repair room or shop proper and a proving room. The proving room shall be designed so that meters and meter testing apparatus are protected from excessive changes in temperature and other disturbing factors. The proving room or the entire meter shop shall be air conditioned if necessary to achieve satisfactory temperature control.

3. The proving room shall be well lighted and preferably not on an outside wall of the building. Temperatures within the proving room shall not vary more than two (2) degrees Fahrenheit per hour nor more than five (5) degrees Fahrenheit over a twenty-four (24) hour period.

(b) Working standards.

1. Each utility, unless specifically excepted by the commission, shall own and make proper provision to operate at least one (1) approved belltype meter prover, preferably of ten (10) cubic feet capacity, but in no case of less than five (5) cubic feet capacity. The prover shall be equipped with suitable thermometers and other necessary accessories. This equipment shall be maintained in proper condition and adjustment so that it shall be capable of determining the accuracy of any service meter, practical to test by it, to within one-half (1/2) of one (1) percent plus or minus.

2. The prover shall be accurate to within three-tenths (0.3) of one (1) percent at each point used in testing meters.

3. The prover shall not be located near any radiator, heater, steam pipe, or hot or cold air duct. Direct sunlight shall not be allowed to fall on the prover or the meters under test.

4. During conditions of satisfactory operation air temperature in the prover shall be within one (1) degree Fahrenheit of the ambient temperature, and oil temperature in the prover shall not differ from the temperature of ambient air by more than one (1) degree Fahrenheit.

5. Meters to be tested shall be stored in such manner that temperature of the meters is substantially the same as temperature of the prover. To achieve this, meters shall be placed in the environment of the prover for a minimum of five (5) hours.

(c) All testing instruments and other equipment certified by the commission shall be accompanied at all times by a certificate showing the date when it was last tested and adjusted. The certificate must be signed by a proper authority designated by the commission. A tag referring to such certificate may be attached to the instruments when practicable. These certificates, when superseded, shall be kept on file by the utility.

(d) Sixty (60) days after the effective date of a commission order granting convenience and necessity for a new utility, that utility shall advise the commission in writing as to kind and amount of testing equipment available.

(5) Periodic tests.

(a) Periodic tests of all meters shall be made according to the following schedule based on rated capacities. Rated meter capacity is defined as the capacity of the meter at five-tenths (0.5) of one (1) inch water column differential for diaphragm meters and as specified by the manufacturer for all other meters.

1. Positive-displacement meters, with rated capacity up to and including 500 cubic feet per hour, shall be tested at least once every ten (10) years.

2. Positive-displacement meters, with rated capacity above 500 cubic feet per hour, up to and including 1,500

cubic feet per hour, shall be tested at least once every five (5) years.

3. Positive-displacement meters above 1,500 cubic feet per hour shall be tested at least once every year.

4. Orifice meters shall have their recording gauges tested at least once every six (6) months. Orifice size and condition shall be checked at the required meter test interval.

5. Auxiliary measurement devices such as pressure, temperature, volume, load demand and remote reading devices shall be tested at the required meter test interval.

(b) Whenever the number of meters of any type which register in error beyond the limits specified in these rules is deemed excessive, this type shall be tested with such additional frequency as the commission may direct.

(c) A utility desiring to adopt a scientific sample meter test plan for positive displacement meters in accordance with parameters established by the commission shall submit its application to the commission for approval. Upon approval, the sample testing plan may be followed in lieu of tests prescribed in subsections (3) and (5) of this section and 807 KAR 5:006, Section 13(1).

(6) Measuring production and shipment into and out of the state.

(a) The utility shall measure and record the quantity of all gas produced and purchased by it in Kentucky.

(b) The utility shall measure and record the quantity of all gas piped out of or brought into the state of Kentucky.

Section 9. Customer Meters, Service Regulators, and Service Lines. (1) Scope. This section prescribes minimum requirements for installing customer meters, service regulators, service lines, service line valves, and service line connections to mains.

(2) Customer meters and regulators: location.

(a) Each meter and service regulator, whether inside or outside of a building, shall be installed in a readily accessible location and protected from corrosion and other damage.

(b) Meters shall be easily accessible for reading, testing and making necessary adjustments and repairs, and where indoor type meters are necessary they shall be installed in a clean, dry, safe, convenient place. Unless absolutely unavoidable, meters shall not be installed in any location where visits of the meter reader or tester will cause annoyance to the customer or severe inconvenience to the utility. Existing meters located in places not permitted by rule shall be relocated by the customer or owner to an approved position.

(c) Proper provision shall be made by the customer for installation of the utility's meter. At least six (6) inches clear space shall be available, if possible, on all sides of the meter and not less than thirty (30) inches in front of it. When installed within a building, a meter shall be located in a ventilated place and not less than three (3) feet from any source of ignition or any source of heat which might damage the meter.

(d) When a number of meters are placed in the same location, each meter shall be tagged or marked to indicate the customer served by it and such identification shall be preserved and maintained by the owner of the premises served.

(e) When the distance between the utility's main and nearest point of consumption is more than 150 feet, the meter shall be located as near to the utility's main as may be practicable. This provision shall apply when any part of the service line has been constructed by either the customer or utility.

(f) When a customer is served from a pipeline operating in excess of sixty (60) psig the meters, regulators and safety devices shall be located as near to the utility's pipeline as practicable.

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

(h) Where feasible, the upstream regulator in a series shall be located outside the building unless it is located in a separate metering or regulating building.

(3) Customer meters and regulators: protection from damage.

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

(b) Service regulator vents and relief vents. Service regulator vents and relief vents shall terminate outdoors, and the outdoor terminal shall be:

1. Rain and insect resistant;

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

3. Protected from damage caused by submergence in areas where flooding may occur.

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

(4) Customer meter and regulators: installation.

(a) Each meter and each regulator shall be installed to minimize anticipated stresses upon the connecting piping

and the meter.

(b) Use of all thread (close) nipples is prohibited.

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

(d) Each regulator that might release gas in its operation shall be vented to the outside atmosphere and shall have a vent pipe sized no smaller than the manufacturer's vent connection built into the regulator.

(5) Customer meter installation: operation pressure.

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

(b) Each newly installed meter manufactured after November 12, 1970, shall have been tested to a minimum of ten (10) psig.

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

(6) Service lines: installation.

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

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

(c) Grading for drainage. Where condensation in the gas might cause interruption in gas supply to the customer, the service line shall be graded to drain into the main or into drips at low points in the service line.

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

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

1. If a metal service line, be protected against corrosion;

2. If a plastic service line, be protected from shearing action and backfill settlement; and

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

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

1. It shall be encased in a gastight conduit;

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

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

(g) Joining of service lines. All underground steel service lines shall be joined by threaded and coupled joints, compression type fittings, or by qualified welding procedures and operators.

(h) When coated steel pipe is to be installed as a service line in a bore, care shall be exercised to prevent damage to the coating during installation. For all installations to be made by boring, driving or similar methods or in a rocky type soil, the following practices or their equivalents are recommended:

1. Coated pipe should not be used as the bore pipe or drive pipe and left in the ground as part of the service line. It is preferable to make such installations by first making an average bore, removing the pipe used for boring and then inserting the coated pipe.

2. Coated steel pipe preferably should not be inserted through a bore in exceptionally rocky soil when there is a likelihood of damage to the coating resulting from insertion.

3. Recommendations in subparagraphs 1 and 2 of this subsection do not apply where coated pipe is installed under conditions where the coating is not likely to be damaged, such as in sandy soil.

(7) Service line: valve requirements.

(a) Each service line shall have a service-line valve that meets applicable requirements of Sections 2 and 4 of this administrative regulation. A valve incorporated in a meter bar, that allows the meter to be bypassed, shall not be used as a service-line valve.

(b) A soft seal service-line valve shall not be used if its ability to control flow of gas could be adversely affected by exposure to anticipated heat.

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

(8) Service lines: location of valves.

(a) Relation to regulator or meter. Each service-line valve shall be installed upstream of the regulator or, if there is not regulator, upstream of the meter.

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

(c) Underground valves. Each underground service-line valve shall be located in a covered, durable curb box or standpipe that allows ready operation of the valve. The curb box shall be supported independently of the service lines.

(9) Service lines general requirements for connections to main piping.

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

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

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

2. If gaskets are used in connecting the service line to the main connection fitting, gaskets shall be compatible with the kind of gas in the system.

(10) Service lines: connection to cast iron or ductile iron mains.

(a) Each service line connected to a cast iron or ductile iron main shall be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting requirements of Section 6(2) of this administrative regulation.

(b) If a threaded tap is being inserted, the requirements of Section 4(6)(b) and (c) of this administrative regulation shall also be met.

(11) Service lines: steel. Each steel service line to be operated at less than 100 psig shall be constructed of pipe designed for a minimum of 100 psig.

(12) Service lines: cast iron and ductile iron. Cast or ductile iron pipe shall not be installed for service lines.

(13) Service lines: plastic.

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

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

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

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

(14) Service lines: copper. Each copper service line installed within a building shall be protected against external damage.

(15) New service lines not in use. Each service line not placed in service upon completion of installation shall comply with one (1) of the following until the customer is supplied with gas:

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

(b) A mechanical device or fitting that will prevent 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 sealed.

(16) Extension of services.

(a) Normal extension. An extension of 100 feet or less shall be made by a utility to an existing distribution main without charge for a prospective customer who shall apply for and contract to use service for one (1) year or more and provides guarantee for such service.

(b) Other extensions.

1. When an extension of the utility's main to serve an applicant or group of applicants amounts to more than 100 feet per customer, the utility shall, if not inconsistent with its filed tariff, require the total cost of the excessive footage over 100 feet per customer to be deposited with the utility by the applicant(s), based on average estimated cost per foot of the total extension.

2. Each customer receiving service under such extension will be reimbursed under the following plan: each year for a refund period of not less than ten (10) years, the utility shall refund to the customer(s) who paid for the excessive footage, the cost of 100 feet of extension in place for each additional customer connected during the year whose service line is directly connected to the extension installed, and not to extensions or laterals therefrom. Total amount refunded shall not exceed the amount paid to the utility. After the end of the refund period, no refund shall be required.

(c) An applicant desiring an extension to a proposed real estate subdivision may be required to pay all costs of the extension. Each year for a refund period of not less than ten (10) years, the utility shall refund to the applicant who paid for the extension a sum equivalent to the cost of 100 feet of extension installed for each additional customer connected during the year. Total amount refunded shall not exceed the amount paid to the utility. After the end of the refund period from the completion of the extension, no refund shall be required.

(d) Nothing contained herein shall be construed to prohibit the utility from making extensions under different arrangements provided such arrangements have been approved by the commission.

(e) Nothing contained herein shall be construed to prohibit a utility from making, at its expense, greater extensions than herein prescribed, provided the same free extensions are made to other customers under similar conditions.

(f) Upon complaint to and investigation by the commission, a utility may be required to construct extensions greater than 100 feet upon a finding by the commission that such extension is reasonable.

(17) Service connections.

(a) Ownership of service lines.

1. Utility's responsibility. In urban areas with well defined streets, the utility shall furnish and install at its own expense, for the purpose of connecting its distribution system to customer premises, that portion of service pipe from its main to the property line or to and including the curb stop and curb box if used. The curb stop may be installed at a convenient place between property line and curb. If meters are located outdoors, the curb box and curb stop may be omitted if meter installation is provided with a stopcock and connection to the distribution main is made with a service tee that incorporates a positive shutoff device that can be operated with ordinary, readily available tools and the service tee is not located under pavement.

2. Customer's responsibility. The customer, or the company at its option and with commission approval, shall furnish and lay necessary pipe to make the connection from curb stop to place of consumption and shall keep the service line in good repair and in accordance with reasonable requirements of the utility's rules and the commission's administrative regulations.

3. Inspection. In the installation of a service line, the customer shall not install any tees or branch connections and shall leave the trench open and pipe uncovered until it is examined by an inspector of the utility and shown to be free from any irregularity or defect. The utility shall test all piping downstream from the meter for gas leaks, each time gas is turned on by the utility, by observing that no gas passes through the meter when all appliances are turned off. The utility shall refuse to serve until all gas leaks so disclosed have been properly repaired.

4. Location of service. The customer's service line shall extend to that point on the curb line easiest of access to the utility from its distribution system. When a reasonable doubt exists as to the proper location of the service line, the utility shall be consulted and its approval of the location secured.

(b) All services shall be equipped with a stopcock near the meter. If the service is not equipped with an outside shutoff, the inside shutoff shall be of a type which can be sealed in the off position.

Section 10. Requirements for Corrosion Control. (1) Scope. This subsection prescribes minimum requirements for protection of metallic pipelines from external, internal, and atmospheric corrosion.

(2) Applicability to converted pipelines. Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this administrative regulation in accordance with Section 1(7) of this administrative regulation shall meet the requirements of this subsection specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within one (1) year after the pipeline is readied for service. However, the requirements of this section specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated, or substantially altered.

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

(4) External corrosion control: buried or submerged pipelines installed after July 31, 1971.

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

1. It shall have an external protective coating meeting the requirements of subsection (7) of this section.

2. It shall have a cathodic protection system designed to protect the pipeline in its entirety in accordance with this subsection, installed and placed in operation within one (1) year after completion of construction.

(b) An operator need not comply with paragraph (a) of this subsection if the operator can demonstrate by tests,

investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within six (6) months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed twenty (20) feet, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests indicate that a corrosive condition exists, the pipeline shall be cathodically protected in accordance with paragraph (a)2 of this subsection.

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

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

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

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

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

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

1. For the size fitting used, an operator can show by tests, investigation, or experience in the area of application that adequate corrosion control is provided by alloyage; and

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

(5) External corrosion control: buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating shall be cathodically protected along the entire area that is effectively coated, in accordance with this section. For the purposes of this section, pipeline does not have effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine cathodic protection current requirements.

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

1. Bare or ineffectively coated transmission lines.

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

3. Bare or coated distribution lines. The operator shall determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by study of corrosion and leak history records, leak detection survey, or other means.

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

(6) External corrosion control: examination of buried pipeline when exposed. Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion shall be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion is found, remedial action shall be taken to the extent required by subsection (18) of this section and applicable paragraphs of subsections (19), (20) or (21) of this section.

(7) External corrosion control: protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for external corrosion control shall:

1. Be applied on a properly prepared surface;

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

3. Be sufficiently ductile to resist cracking;

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

5. Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type shall also have low moisture absorption and high electrical resistance.

(c) Each external protective coating shall be inspected just prior to lowering the pipe into the ditch and backfilling, and any damage to effective corrosion control shall be repaired.

(d) Each external protective coating shall be protected from damage resulting from adverse ditch conditions or supporting blocks.

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

(8) External corrosion control: cathodic protection.

(a) Each cathodic protection system required by this subsection shall provide a level of cathodic protection that complies with one (1) or more of the applicable criteria contained in Appendix D of this administrative regulation. If none of these criteria is applicable, the cathodic protection system shall provide a level of cathodic protection at least equal to that provided by compliance with one (1) or more of these criteria.

(b) If amphoteric metals are included in a buried or submerged pipeline containing a metal of different anodic potential:

1. Amphoteric metals shall be electrically isolated from the remaining pipeline and cathodically protected; or

2. The entire buried or submerged pipeline shall be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this administrative regulation for amphoteric metals.

(c) The amount of cathodic protection shall be controlled to prevent damage to protective coating or pipe.

(9) External corrosion control: monitoring.

(a) Each pipeline that is under cathodic protection shall be tested at least once each calendar year but with intervals not exceeding fifteen (15) months to determine whether the cathodic protection meets the requirements of subsection (8) of this section. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet, or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least ten (10) percent of these protected structures, distributed over the entire system shall be surveyed each calendar year, with a different ten (10) percent checked each subsequent year, so that the entire system is tested in each ten (10) year period.

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

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

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

(e) After the initial evaluation required by subsection (4)(b) and (c) and subsection (5)(b) of this section, each operator shall, at intervals not exceeding three (3) years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subsection in areas in which active corrosion is found. The operator shall determine areas of active corrosion by electrical survey, or where electrical survey is impractical, by study of corrosion and leak history records, leak detection survey, or other means.

(10) External corrosion control: electrical isolation.

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

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

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

(d) Inspection and electrical tests shall be made to assure that electrical isolation is adequate.

(e) An insulating device shall not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located close to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it shall be protected against damage due to fault currents or lightning, and protective measures shall be taken at insulating devices. A study shall be made in collaboration with the electric company on common problems of corrosion and electrolysis and taking the following factors into consideration:

1. Possibility of the pipeline carrying either unbalanced line currents or fault currents.

2. Possibility of lightning or fault currents inducing voltages sufficient to puncture pipe coatings or pipe.

3. Cathodic protection of the pipeline, including location of ground beds, especially if the electric line is carried on steel towers.

4. Bonding connections between the pipeline and either the steel tower footings or buried ground facilities or groundwire of the overhead electric system.

(11) External corrosion control: test stations. Each pipeline under cathodic protection required by this subsection

shall have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

(12) External corrosion control: test leads.

(a) Each test lead wire shall be connected to the pipeline to remain mechanically secure and electrically conductive.

(b) Each test lead wire shall be attached to the pipeline to minimize stress concentration on the pipe.

(c) Each bared test lead wire and bared metallic area at point of connection to the pipeline shall be coated with electrical insulating material compatible with the pipe coating and insulation on the wire.

(13) External corrosion control: interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system shall be designed and installed to minimize any adverse effects on existing adjacent underground metallic structures.

(14) Internal corrosion control: general.

(a) Corrosive gas shall not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface shall be inspected for evidence of corrosion. If internal corrosion is found:

1. Adjacent pipe shall be investigated to determine the extent of internal corrosion;

2. Replacement shall be made to the extent required by applicable paragraphs of subsections (19), (20) and (21) of this section; and

3. Steps shall be taken to minimize the internal corrosion.

(c) Gas containing more than one-tenth (0.1) grain of hydrogen sulfide per 100 standard cubic feet shall not be stored in pipe-type or bottle-type holders.

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

(16) Atmospheric corrosion control: general.

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

(b) Pipelines installed before August 1, 1971. Each operator having an aboveground pipeline or portion of pipeline installed before August 1, 1971, exposed to the atmosphere, shall:

1. Determine areas of atmospheric corrosion on the pipeline;

2. If atmospheric corrosion is found, take remedial measures to the extent required by applicable paragraphs of subsections (19), (20), or (21) of this section; and

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

(17) Atmospheric corrosion control: monitoring. After meeting the requirements of subsection (16)(a) and (b) of this section, each operator shall, at intervals not exceeding three (3) years, reevaluate each pipeline exposed to the atmosphere and take protective action whenever necessary against atmospheric corrosion.

(18) Remedial measures: general.

(a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion shall have a properly prepared surface and shall be provided with an external protective coating that meets the requirements of subsection (7) of this section.

(b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion shall be cathodically protected in accordance with this section.

(c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe required to be repaired because of external corrosion shall be cathodically protected in accordance with this section.

(19) Remedial measures: transmission lines.

(a) General corrosion. Each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for maximum allowable operating pressure of the pipeline shall be replaced or operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness.

However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result shall be replaced or repaired, or operating pressure shall be reduced commensurate with the strength of the pipe, based on actual remaining wall thickness in the pits.

(20) Remedial measures: distribution lines other than cast iron or ductile iron lines.

(a) General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with remaining wall thickness less than that required for maximum allowable operating pressure of the pipeline, or remaining wall thickness less than thirty (30) percent of the nominal wall thickness, shall be replaced. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped so as to affect overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

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

(21) Remedial measures: cast iron and ductile iron pipelines.

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

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

(22) Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, other than unrecorded galvanic anodes installed before August 1, 1971, and neighboring structures bonded to the cathodic protection system.

(b) Each of the following records shall be retained for as long as the pipeline remains in service:

1. Each record or map required by paragraph (a) of this subsection.

2. Records of each test, survey, or inspection required by this subsection, in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist.

Section 11. Test Requirements. (1) Scope. This section prescribes minimum leak-test and strength-test requirements for pipelines.

(2) General requirements.

(a) No person shall operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until:

1. It has been tested in accordance with this section and Section 13(11) of this administrative regulation to substantiate maximum allowable operating pressure; and

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

(b) The test medium shall be liquid, air, natural gas or inert gas that is:

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

2. Relatively free of sedimentary materials; and

3. Except for natural gas, nonflammable.

(c) Except as provided in subsection (3)(a) of this section, if air, natural gas or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Maximum Hoop Stress Permissible During Test				
	% of Specified Minimum Yield			
Class Location	1	2	3	4
Test Medium Air or Inert Gas	80	75	50	40
Natural Gas	80	30	30	30

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

(3) Strength test requirements for steel pipeline to operate at hoop stress of thirty (30) percent or more of SMYS:

(a) Except for service lines, each segment of steel pipeline that is to operate at hoop stress of thirty (30) percent or more of SMYS shall be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet of a pipeline, a hydrostatic test shall be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of pipeline within 300 feet of that building, but in no event

may the test section be less than 600 feet unless the length of the newly installed or relocated pipe is less than 600 feet. However, if the buildings are evacuated while hoop stress exceeds fifty (50) percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station, regulator station and measuring station shall be tested to Class 3 location test requirements.

(c) Except as provided in paragraph (e) of this subsection, strength test shall be conducted by maintaining pressure at or above the test pressure for at least eight (8) hours.

(d) If a component other than pipe is the only item being replaced or added to pipeline, a strength test after installation is not required, if the manufacturer of the component certifies that:

1. The component was tested to at least the pressure required for the pipeline to which it is being added; or

2. The component was manufactured under a quality control system that ensures that each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added.

(e) For fabricated units and short sections of pipe, for which a postinstallation test is impractical, a preinstallation strength test shall be conducted by maintaining pressure at or above test pressure for at least four (4) hours.

(4) Test requirements for pipelines to operate at hoop stress less than thirty (30) percent of SMYS and at or above 100 psig. Except for service lines and plastic pipelines, each segment of pipeline to be operated at hoop stress less than thirty (30) percent of SMYS and at or above 100 psig shall be tested in accordance with the following:

(a) The pipeline operator shall use a test procedure that will insure discovery of all potentially hazardous leaks in the segment being tested.

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

1. A leak test shall be made at pressure between 100 psig and the pressure required to produce hoop stress of twenty (20) percent of SMYS; or

2. The line shall be walked to check for leaks while hoop stress is held at approximately twenty (20) percent of SMYS.

(c) Pressure shall be maintained at or above test pressure for at least one (1) hour.

(5) Test requirements for pipelines to operate below 100 psig. Except for service lines and plastic pipelines, each segment of pipeline to be operated below 100 psig shall be leak tested in accordance with the following:

(a) The test procedure used shall ensure discovery of all potentially hazardous leaks in the segment being tested.

(b) Each main to be operated at less than one (1) psig shall be tested to at least ten (10) psig and each main to be operated at or above one (1) psig shall be tested to at least ninety (90) psig.

(6) Test requirements for service lines.

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

(b) Each segment of service line (other than plastic) intended to be operated at a pressure of at least one (1) psig but not more than forty (40) psig shall be given a leak test at pressure of not less than fifty (50) psig.

(c) Each segment of service line (other than plastic) to be operated at pressures of more than forty (40) psig shall be tested to the maximum operating pressure or ninety (90) psig, whichever is greater, except that each segment of steel service line stressed to twenty (20) percent or more of SMYS shall be tested in accordance with subsection (4) of this section.

(7) Test requirements for plastic pipelines.

(a) Each segment of plastic pipeline shall be tested in accordance with this subsection.

(b) The test procedure shall insure discovery of all potentially hazardous leaks in the segment being tested.

(c) The test pressure shall be at least 150 percent of maximum operating pressure or fifty (50) psig, whichever is greater. However, maximum test pressure shall not be more than three (3) times the design pressure of the pipe.

(d) Temperature of thermoplastic material shall be no more than 100 degrees Fahrenheit during the test.

(8) Environmental protection and safety requirements.

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

(b) The operator shall insure that the test medium is disposed of in a manner that will minimize damage to the environment.

(9) Records. Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under subsections (3) and (4) of this section. The record shall contain at least the following information:

(a) Operator's name, name of operator's employee responsible for making the test, and name of any test company used.

(b) Test medium used.

(c) Test pressure.

(d) Test duration.

(e) Pressure recording charts, or other record of pressure readings.

(f) Elevation variations, whenever significant for the particular test.

(g) Leaks and failures noted and their disposition.

Section 12. Uprating. (1) Scope. This subsection prescribes minimum requirements for increasing maximum allowable operation pressures (uprating) for pipelines.

(2) General requirements.

(a) Pressure increases. Whenever provisions of this subsection require that an increase in operating pressure be made in increments, pressure shall be increased gradually, at a rate that can be controlled, and in accordance with the following:

1. At the end of each incremental increase, pressure shall be held constant while the entire segment of pipeline affected is checked for leaks.

2. Each leak detected shall be repaired before a further pressure increase is made, except that a leak deemed nonhazardous need not be repaired, if it is monitored during pressure increase and it does not become hazardous.

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

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

(d) Limitation on increase in maximum allowable operating pressure. Except as provided in subsection (3) of this section, a new maximum allowable operating pressure established under this subsection shall not exceed the maximum that would be allowed under this part for a new segment of pipeline constructed of the same materials in the same location.

(3) Uprating to a pressure that will produce hoop stress of thirty (30) percent or more of SMYS in steel pipeline.

(a) Unless the requirements of this section have been met, no person shall subject any segment of steel pipeline to operating pressure that will produce hoop stress of thirty (30) percent or more of SMYS and that is above the established maximum allowable operating pressure.

(b) Before increasing operating pressure above previously established maximum allowable operating pressure the operator shall:

1. Review the design, operation, and maintenance history, and previous testing of the segment of pipeline to determine if the proposed increase is safe and consistent with the requirements of this part; and

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

(c) After complying with paragraph (b) of this subsection, an operator may increase maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under Section 13(11) of this administrative regulation, using as test pressure the highest pressure subjected (either in a strength test or in actual operation).

(d) After complying with paragraph (b) of this subsection, an operator that does not qualify under paragraph (c) of this subsection may increase the previously established maximum allowable operating pressure if at least one (1) of the following requirements is met:

1. The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location.

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

a. It is impractical to test it in accordance with the requirements of this part;

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

c. The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this administrative regulation.

(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d) of this subsection, the increase in pressure shall be made in increments that are equal to:

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

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

(4) Uprating: Steel pipelines to a pressure that will produce hoop stress less than thirty (30) percent of SMYS; plastic, cast iron, and ductile iron pipelines.

(a) Unless requirements of this subsection have been met, no person shall subject:

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

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

(b) Before increasing operation pressure above the previously established maximum allowable operating pressure, the operator shall:

1. Review the design, operation, and maintenance history of the segment of pipeline;

2. Make a leakage survey (if it has been more than one (1) year since the last survey) and repair any leaks that are found, except that a leak deemed nonhazardous need not be repaired, if it is monitored during the pressure increase and it does not become hazardous;

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

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

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

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

(c) After complying with paragraph (b) of this subsection, the increase in maximum allowable operating pressure shall be made in increments equal to ten (10) psig or twenty-five (25) percent of total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)6 of this subsection apply, there shall be at least two (2) approximately equal incremental increases.

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

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

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

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

	Allowance (inches)		
	Cast iron pipe		
Pipe size (inches)	Pit cast pipe	Centrifugally cast pipe	Ductile iron pipe
3-8	0.075	0.065	0.065
10-12	0.08	0.07	0.07
14-24	0.08	0.08	0.075
30-42	0.09	0.09	0.075
48	0.09	0.09	0.08
54-60	0.09		

4. For cast iron pipe, unless the pipe manufacturing process is known, the operator shall assume that the pipe is pit cast pipe with bursting tensile strength of 11,000 psig and modulus of rupture of 31,000 psig.

Section 13. Operations. (1) Scope. This section prescribes minimum requirements for operation of pipeline facilities.

(2) General provisions.

(a) No person shall operate a segment of pipeline unless it is operated in accordance with this section.

(b) Each operator shall establish a written operating and maintenance plan meeting the requirements of this administrative regulation and keep records necessary to administer the plan.

(3) Essentials of operating and maintenance plan. Each operator shall include the following in its operating and maintenance plan:

(a) Instructions for employees covering operating and maintenance procedures during normal operations and repairs.

(b) Items required to be included by the provisions of Section 14 of this administrative regulation.

(c) Specific programs relating to facilities presenting the greatest hazard to public safety either in an emergency or because of extraordinary construction or maintenance requirements.

(d) A program for conversion procedures, if conversion of a low-pressure distribution system to higher pressure is contemplated.

(e) Provision for periodic inspections to ensure that operating pressures are appropriate for class location.

(f) Instructions enabling personnel who perform operation and maintenance activities to recognize conditions that are potentially safety-related conditions subject to reporting requirements of 807 KAR 5:027, Section 12.

(4) Initial determination of class location and confirmation or establishment of maximum allowable operating pressure.

(a) Before April 15, 1971, each operator shall complete a study to determine for each segment of pipeline with maximum allowable operating pressure that will produce hoop stress that is more than forty (40) percent of SMYS:

1. The present class location of all such pipelines in its system; and

2. Whether hoop stress corresponding to maximum allowable operating pressure for each segment of pipeline is commensurate with the present class location.

(b) Each segment of pipeline that has been determined under paragraph (a) of this subsection to have an established maximum allowable operating pressure producing hoop stress not commensurate with the class location of the segment of pipeline and that is found in satisfactory condition, shall have the maximum allowable operating pressure confirmed or revised in accordance with subsection (6) of this section. Confirmation or revision shall be completed not later than December 31, 1974.

(c) Each operator required to confirm or revise an established maximum allowable operating pressure under paragraph (b) of this subsection shall, not later than December 31, 1971, prepare a comprehensive plan, including a schedule, for carrying out the confirmations or revisions. The comprehensive plan must also provide for confirmations or revisions determined to be necessary under subsection (5) of this section, to the extent that they are caused by changes in class locations taking place before July 1, 1973.

(5) Change in class location: required study. Whenever increase in population density indicates a change in class location for a segment of existing steel pipeline operating at hoop stress that is more than forty (40) percent of SMYS, or indicates that hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) Present class location for the segment involved;

(b) Design, construction, and testing procedures followed in original construction, and a comparison of these procedures with those required for the present class location by applicable provisions of this part;

(c) Physical condition of the segment to the extent it can be ascertained from available records;

(d) Operating and maintenance history of the segment;

(e) Maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and

(f) Actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

(6) Change in class location: confirmation or revision of maximum allowable operating pressure. If hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline shall be confirmed or revised according to one (1) of the

following requirements:

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

(b) The maximum allowable operating pressure shall be reduced so that corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(c) The segment involved shall be tested in accordance with applicable requirements of Section 11 of this administrative regulation, and its maximum allowable operating pressure shall then be established according to the following criteria:

1. Maximum allowable operating pressure after the requalification test is eight-tenths (0.8) times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

2. Maximum allowable operating pressure confirmed or revised in accordance with this subsection, shall not exceed maximum allowable operating pressure established before confirmation or revision.

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

(d) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of Section 12(2) and (3) of this administrative regulation.

(e) Confirmation or revision of maximum allowable operating pressure that is required as a result of subsection (5) of this section shall be completed within eighteen (18) months of the change in class location. Pressure reduction under paragraphs (a) and (b) of this subsection within the eighteen (18) month period does not preclude establishing a maximum allowable operating pressure under paragraph (c) of this subsection at a later date.

(7) Continuing surveillance.

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

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with subsection (11)(a) and (b) of this section.

(8) Damage prevention program.

(a) Except for pipelines listed in paragraph (c) of this subsection, each operator of a buried pipeline shall carry out in accordance with this subsection a written program to prevent damage to that pipeline by excavation activities. For the purpose of this subsection, "excavating activities" include excavation, blasting, boring, tunneling, backfilling, removal of aboveground structures by either explosive or mechanical means, and other earth moving operations. An operator may perform any duties required by paragraph (b) of this subsection through participation in a public service program, such as a "one-call" system, but such participation does not relieve the operator of responsibility for compliance with this subsection.

(b) The damage prevention program required by paragraph (a) of this subsection shall, at a minimum:

1. Include the identity, on a current basis, of persons who normally engage in excavation activities in the vicinity of the pipeline.

2. Provide for notification to the public in the vicinity of the pipeline and actual notification to persons identified in paragraph (b)1 of this subsection as often as needed to make them aware of the existence and purpose of the damage prevention program and how to learn the location of underground pipelines prior to excavation activities.

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

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

5. Provide for temporary marking of buried pipelines near excavation activity before, as far as practical, activity begins.

6. Provide for frequent inspection of pipeline an operator has reason to believe could be damaged by excavation activities to verify the integrity of the pipeline; and in the case of blasting, any inspection shall include leakage surveys.

(c) A damage prevention program under this subsection is not required for the following pipelines:

1. Pipelines in a Class 1 or 2 location.

2. Pipelines in a Class 3 location defined by Section 1(3)(d)2 of this administrative regulation that are marked in accordance with Section 14(5) of this administrative regulation.

3. Pipelines to which access is physically controlled by the operator.

4. Pipelines that are part of a petroleum gas system subject to Section 1(6) of this administrative regulation or part of a distribution system operated by a person in connection with that person's leasing of real property or by a condominium or cooperative association.

(9) Emergency plans.

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

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

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

3. Prompt and effective response to a notice of each type of emergency, including gas, fire, explosion or natural disaster near or involving a building with gas pipeline or pipeline facility.

4. Availability of personnel, equipment, tools, and materials, as needed at the scene of emergency.

5. Actions directed toward protecting people first and then property.

6. Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

7. Making safe any actual or potential hazard to life or property.

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

9. Safely restoring any service outage.

10. Beginning action under subsection (10) of this section, if applicable, as soon after the end of the emergency as possible.

(b) Each operator shall:

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

2. Train appropriate operating personnel in emergency procedures and verify that training is effective.

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

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

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

2. Acquaint officials with the operator's ability to respond to a gas pipeline emergency;

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

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

(d) Each operator shall establish a continuing educational program to enable customers, the public, appropriate governmental organizations, and person engaged in excavation-related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or appropriate public officials. The program and media used shall be as comprehensive as necessary to reach all areas in which the operator transports gas. The program shall be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

(10) Investigation of failures. Each operator shall establish procedures for analyzing accidents and failure, including selection of samples of the failed facility or equipment for laboratory examination, where appropriate, to determine the causes of the failure and to minimize the possibility of recurrence.

(11) Maximum allowable operating pressure: steel or plastic pipelines.

(a) Except as provided in paragraph (c) of this subsection, no person shall operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

1. Design pressure of the weakest element in the segment, determined in accordance with Sections 3 and 4 of this administrative regulation.

2. Pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

a. For plastic pipe in all locations, test pressure is divided by a factor of one and five-tenths (1.5).

b. For steel pipe operated at 100 psig or more, test pressure is divided by a factor determined in accordance with the following table:

Class	Segment	Segment	Converted

Location	Installed Before 11/12/70	Installed After 11/11/70	under Section 1(8)
1	1.10	1.10	1.25
2	1.25	1.25	1.25
3	1.40	1.50	1.50
4	1.40	1.50	1.50

3. Highest actual operating pressure to which the segment was subjected during the five (5) years preceding July 1, 1970, unless the segment was tested in accordance with paragraph (a)2 of this subsection after July 1, 1965, or the segment was uprated in accordance with Section 12 of this administrative regulation.

4. For furnace butt welded steel pipe, pressure equal to sixty (60) percent of the mill test pressure to which the pipe was subjected.

5. For steel pipe other than furnace butt welded pipe, pressure equal to eighty-five (85) percent of the highest test pressure to which the pipe has been subjected, whether by mill test or by post installation test.

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

(b) No person shall operate a segment to which paragraph (a)6 of this subsection is applicable, unless overpressure protective devices are installed on the segment to prevent maximum allowable operating pressure from being exceeded, in accordance with Section 4(30) of this administrative regulation.

(c) Notwithstanding other requirements of this subsection, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the five (5) years preceding July 1, 1970.

(12) Maximum allowable operating pressure: high-pressure distribution systems.

(a) No person shall operate a segment of high-pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

1. Design pressure of the weakest element in the segment, determined in accordance with Sections 3 and 4 of this administrative regulation.

2. Sixty (60) psig, for a segment of a distribution system otherwise designed to operate at over sixty (60) psig, unless service lines in the segment are equipped with service regulators or other pressure limited devices in series that meet the requirements of Section 4(31)(c) of this administrative regulation.

3. Twenty-five (25) psig, in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

4. Pressure limits to which a joint could be subjected without parting.

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

(b) No person shall operate a segment of pipeline to which paragraph (a)5 of this subsection applies, unless overpressure protective devices are installed on the segment to prevent the maximum allowable operating pressure from being exceeded, in accordance with Section 4(30) of this administrative regulation.

(13) Maximum and minimum allowable operating pressure: low-pressure distribution systems.

(a) No person shall operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person shall operate a low-pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

(14) Standard pressure.

(a) All utilities supplying gas for light, heat, power or other purposes shall, subject to approval of the commission, adopt and maintain a standard pressure as measured at the customer's meter outlet. In adopting such standard pressure the utility may divide its distribution system into districts and establish a separate standard pressure for each district, or the utility may establish a single standard pressure for its distribution system as a whole.

(b) The standard pressure to be adopted as provided in this section shall be a part of the utility's schedule of rates and general rules and administrative regulations.

(c) No change shall be made by a utility in standard pressure or pressure adopted except in case of emergency.

(15) Allowable variations of standard service pressure.

(a) Variations of standard pressure as established under the preceding rule shall not exceed the adopted pressure by more than fifty (50) percent plus or minus.

(b) A utility supplying gas shall not be deemed to have violated paragraph (a) of this subsection, if it can be shown that variations from said pressure are due to:

1. Use of gas by the customer in violation of contract under the rules of the utility.

2. Infrequent fluctuations of short duration due to unavoidable conditions of operation.

(c) Allowable variations in standard pressure other than those covered by paragraph (a) of this subsection shall be established by the commission when application is made and good cause shown for allowance.

(d) The gas pressures required above shall be maintained at the outlet of the meter to provide safe and efficient utilization of gas in properly adjusted appliances supplied through adequately sized customer's facilities.

(16) Continuity of service.

(a) The utility shall keep a complete record of all interruptions on its entire system or on major divisions of its system. The record shall show the cause of interruption, date, time, duration, remedy and steps taken to prevent recurrence. The commission shall be notified of major interruptions as soon as they come to the attention of the utility and a complete report made after restoration of service.

(b) Interruption of service, as used here, shall also mean the interval of time during which pressure drops below fifty (50) percent of such adopted standard pressure on the entire system, or on one (1) or more entire major division or divisions for which an average standard pressure has been adopted.

(17) Odorization of gas.

(a) Combustible gas in a distribution line shall contain a natural odorant or be odorized so that at a concentration in air of one-fifth (1/5) of the lower explosive limit (approximately one (1) percent by volume), gas is readily detectable by a person with a normal sense of smell.

(b) Combustible gas in a transmission line in a Class 3 or Class 4 location shall comply with the requirements of paragraph (a) of this subsection unless:

1. At least fifty (50) percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

2. The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975:

a. Underground storage field;

b. Gas processing plant;

c. Gas dehydration plant; or

d. Industrial plant using gas in a process where presence of an odorant makes the end product unfit for the purpose for which it is intended; reduces the activity of a catalyst; or reduces the percentage completion of a chemical reaction.

3. When lateral line transports gas to a distribution center, at least fifty (50) percent of the length of that line is in a Class 1 or Class 2 location.

(c) Odorant shall not be harmful to persons, materials, or pipe.

(d) Products of combustion from the odorant shall not be toxic when breathed nor shall they be corrosive or harmful to those materials to which the products of combustion will be exposed.

(e) Odorant shall not be soluble in water to an extent greater than two and one-half (2.5) parts to 100 parts by weight.

(f) Equipment for odorization shall introduce odorant without wide variations in the level of odorant.

(g) Each utility shall conduct sampling of combustible gases to assure proper concentration of odorant in accordance with this section unless otherwise approved by the commission.

1. The utility shall sample gases in each separately odorized system at approximate furthest point from injection of odorant.

2. Sampling shall be conducted with equipment designed to detect and verify proper level of odorant.

3. Separately odorized systems with ten (10) or fewer customers shall be sampled for proper odorant level at least once each ninety-five (95) days.

4. Separately odorized systems with more than ten (10) customers shall be sampled for proper odorant level at least once each week.

(18) Tapping pipelines under pressure. Each tap made on a pipeline under pressure shall be performed by a crew qualified to make hot taps.

(19) Purging of pipelines.

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

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

Section 14. Maintenance. (1) Scope. This section prescribes minimum requirements for maintenance of pipeline facilities.

(2) General.

(a) No person shall operate a segment of pipeline, unless it is maintained in accordance with this section.

(b) Each segment of pipeline that becomes unsafe shall be replaced, repaired, or removed from service.

(c) Hazardous leaks must be repaired promptly.

(3) Transmission lines: patrolling.

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

(b) Frequency of patrols is determined by size of line, operating pressures, class location, terrain, weather, and other relevant factors, but intervals between patrols shall not be longer than prescribed in the following table:

Class Location of Line	Maximum Interval Between Periods	
	At Highway and Railroad Crossings	At All Other Places
1 & 2	7 1/2 months; but at least twice each calendar year	15 months; but at least once each calendar year
3	4 1/2 months; but at least four times each calendar year	7 1/2 months; but at least twice each calendar year
4	4 1/2 months; but at least four times each calendar year	4 1/2 months; but at least four times each calendar year

(4) Transmission lines: leakage surveys.

(a) Each operator of a transmission line shall provide for periodic leakage surveys of line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line shall be conducted at intervals not exceeding fifteen (15) months; but at least once each calendar year. However, if a transmission line transports gas in conformity with Section 13(17) of this administrative regulation without an odor or odorant, leakage surveys using leak detector equipment shall be conducted;

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

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

(5) Line markers for mains and transmission lines.

(a) Buried pipelines. Except as provided in paragraph (b) of this subsection, a line marker shall be placed and maintained as close as practical over each buried main and transmission line:

1. At each crossing of a public road or railroad; and

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

(b) Exceptions for buried pipelines. Line markers are not required for buried mains and transmission lines:

1. Located under inland navigable waters;

2. In Class 3 or Class 4 locations:

a. Where placement of a marker is impractical; or

b. Where a damage prevention program is in effect under Section 13(8) of this administrative regulation; or

3. In the case of navigable waterway crossings, within 100 feet of a line marker placed and maintained at that waterway in accordance with this section.

(c) Pipelines above ground. Line markers shall be placed and maintained along each section of a main and transmission line located above ground in an area accessible to the public.

(d) Markers other than at navigable waterways. The following shall be written legibly on a background of sharply contrasting color on each line marker not placed at a navigable waterway:

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

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

all times.

(e) Markers at navigable waterways. Each line marker at a navigable waterway shall have the following characteristics:

1. A rectangular sign with a narrow strip along each edge, colored international orange, and the area between lettering on the sign and boundary strips colored white.

2. Written on the sign in block style, black letters:

a. The word "Warning," "Caution," or "Danger," followed by the words, "Do Not Anchor or Dredge" and the words, "Gas (or name of gas transported Pipeline Crossing;" and

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

3. In overcast daylight, the sign is visible and the writing required by paragraph (e)2a of this subsection is legible, from approaching or passing vessels that may damage or interfere with the pipeline.

(6) Transmission lines: recordkeeping. Each utility shall keep records covering each leak discovered, repair made, transmission line break, leakage survey, line patrol, and inspection, for as long as the segment of transmission line involved remains in service.

(7) Transmission lines: general requirements for repair procedures.

(a) Each utility shall take immediate temporary measures to protect the public whenever:

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

2. It is not feasible to make a permanent repair at the time of discovery. As soon as feasible, the utility shall make permanent repairs. Except as provided in subsection (10)(a)3 of this section, no utility shall use a welded patch as a means of repair.

(8) Transmission lines: permanent field repair of imperfections and damages.

(a) Except as provided in paragraph (b) of this subsection, each imperfection or damage that impairs serviceability of a segment of steel transmission line operating at or above forty (40) percent of SMYS must be repaired as follows:

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

2. If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design shall be applied over the imperfection or damage.

3. If the segment is not taken out of service, operating pressure shall be reduced to a safe level during repairs.

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

(9) Transmission lines: permanent field repair of welds. Each weld that is unacceptable under Section 5(11)(c) of this administrative regulation shall be repaired as follows:

(a) If it is feasible to take the segment of transmission line out of service, the weld shall be repaired in accordance with applicable requirements of Section 5(13) of this administrative regulation.

(b) A weld may be repaired in accordance with Section 5(13) of this administrative regulation while the segment of transmission line is in service if:

1. The weld is not leaking;

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

3. Grinding of the defective area can be limited so that at least one-eighth (1/8) inch thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this subsection shall be repaired by installing a full encirclement welded split sleeve of appropriate design.

(10) Transmission lines: permanent field repair of leaks.

(a) Except as provided in paragraph (b) of this subsection, each permanent field repair of a leak on a transmission line shall be made as follows:

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

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

a. Is joined by mechanical couplings; and

b. Operates at less than forty (40) percent of SMYS.

3. If the leak is due to a corrosion pit, repair may be made by installing properly designed bolt-on leak clamp. If

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

(b) Submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

(11) Transmission lines: testing of repairs.

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

(b) Testing of repairs made by welding. Each repair made by welding in accordance with subsections (8), (9) and (10) of this section shall be examined in accordance with Section 5(11) of this administrative regulation.

(12) Distribution systems: patrolling.

(a) The frequency of patrolling mains shall be determined by the severity of conditions which could cause failure or leakage, and the consequent hazards to public safety.

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage shall be patrolled at intervals not exceeding four and one-half (4 1/2) months, but at least four (4) times each calendar year.

(13) Distribution systems: leakage surveys and procedures.

(a) Each utility shall provide for periodic leakage surveys in its operating and maintenance plan.

(b) The type and scope of the leakage control program shall be determined by the nature of the operations and local conditions; but it shall meet the following minimum requirements:

1. At least once each calendar year, but at intervals not exceeding fifteen (15) months, a gas detector survey shall be conducted in business districts, involving tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, and where access is not denied at inside basement walls of public and commercial buildings located adjacent to gas mains and service lines, at cracks in pavement and sidewalks and at other locations providing an opportunity for finding gas leaks.

2. Leakage surveys of the distribution system outside of principal business areas shall be made as frequently as necessary, but at intervals not exceeding five (5) years.

(c) Each gas utility shall maintain a record for five (5) years of gas leaks reported by the public, utility employees, or detected by leak surveys.

(d) Each leak detected shall be graded according to the following standard:

1. Grade 1 - hazardous leaks. A leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until conditions are no longer hazardous.

2. Grade 2 - nonhazardous leaks. A leak that is recognized as being nonhazardous at time of detection but justifies scheduled repair based on probable future hazard.

3. Grade 3 - nuisance leaks. A leak that is nonhazardous at time of detection and can be reasonably expected to remain nonhazardous. Grade 3 leaks shall be monitored and reevaluated until the leak is regraded or no longer results in a reading.

(14) Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this subsection, each disconnected service line shall be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main shall be tested from point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

(15) Abandonment or inactivation of facilities.

(a) Each utility shall provide in its operating and maintenance plan for abandonment or deactivation of pipelines, including provisions for meeting each requirement of this subsection.

(b) Each pipeline abandoned in place shall be disconnected from all sources and supplies of gas, purged of gas, and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is not potential hazard.

(c) Except for service lines, each inactive pipeline not being maintained under this section shall be disconnected from all sources and supplies of gas, purged of gas, and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is not potential hazard.

(d) Whenever service to a customer is discontinued, one (1) of the following steps shall be taken:

1. The valve that is closed to prevent flow of gas to the customer shall be provided with a locking device or other

means designed to prevent opening of the valve by persons other than those authorized by the utility.

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

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

(e) If air is used for purging, the utility shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault shall be filled with suitable compacted material.

(16) Compressor stations: procedures for gas compressor units. Each utility shall establish starting, operating, and shutdown procedures for gas compressor units.

(17) Compressor stations: inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station shall be inspected and tested in accordance with subsections (21) and (23) of this section, and shall be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found shall be promptly repaired or replaced.

(c) Each remote control shutdown device shall be inspected and tested at intervals not to exceed fifteen (15) months, but at least once each calendar year to determine that it functions properly.

(18) Compressor stations: isolation of equipment for maintenance or alterations. Each utility shall establish procedures for maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(19) Compressor stations: storage of combustible materials.

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

(b) Above ground oil or gasoline storage tanks shall be protected in accordance with National Fire Protection Association Standard No. 30.

(20) Pipe-type and bottle-type holders: plan for inspection and testing. Each utility having a pipe-type or bottle-type holder shall establish a plan for systematic, routine inspection and testing of these facilities, including the following:

(a) Provision shall be made for detecting external corrosion before strength of the container has been impaired.

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

(c) Pressure control and pressure limiting equipment shall be inspected and tested periodically to determine that it is in a safe operating condition and has adequate capacity.

(21) Pressure limiting and regulating stations: inspection and testing. Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment shall be subjected, at intervals not exceeding fifteen (15) months, but at least once each calendar year, to inspections and tests to determine that it is:

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the correct pressure; and

(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(22) Pressure limiting and regulating stations: telemetering or recording gauges.

(a) Each utility shall keep in continual use one (1) or more accurate recording pressure gauges on its distribution systems. These gauges shall be located at such points and in such manner sufficient to reflect a continuous record of gas pressure and character of service being furnished throughout the entire system.

(b) In addition to the recording pressure gauges required in paragraph (a) of this subsection, all utilities distributing gas shall maintain one (1) or more portable recording pressure gauges with which pressure surveys shall be made in sufficient number to indicate the service furnished and to satisfy the commission of the utility's compliance with pressure requirements.

(c) All recording pressure charts or records shall be preserved and filed in a systematic manner and each chart shall show date and location when the record was made. All charts or records shall be kept on file by the utility for at least two (2) years.

(d) If there are indications of abnormally high or low-pressure, the regulator and auxiliary equipment shall be inspected and necessary measures employed to correct any satisfactory operating conditions.

(23) Pressure limiting and regulating stations: testing of relief devices.

(a) If feasible, pressure relief devices (except rupture discs) shall be tested in place, at intervals not exceeding fifteen (15) months, but at least once each calendar year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station shall be made, at intervals not exceeding fifteen (15) months, but at least once each calendar year. These required capacities shall be compared with the rated or experimentally determined relieving capacity of the device for operating conditions under which it works. After initial calculations, subsequent calculations are not required if review documents show that parameters have not changed to cause capacity to be less than required.

(c) If the relieving device is of insufficient capacity, a new or additional device shall be installed to provide the additional capacity required.

(24) Valve maintenance: transmission lines. Each transmission line valve that might be required during any emergency shall be inspected and partially operated, at intervals not exceeding fifteen (15) months, but at least once each calendar year.

(25) Valve maintenance: distribution systems. Each valve, the use of which may be necessary for safe operation of a distribution system, shall be checked and serviced, at intervals not exceeding fifteen (15) months, but at least once each calendar year.

(26) Vault maintenance.

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

(b) Inspection of each vault, its cover, and equipment shall include checks for proper ventilation, function, and safety. Any leaks shall be corrected immediately.

(27) Prevention of accidental ignition. Each utility shall take steps to minimize the danger of accidental gas ignition in any structure or area where presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition shall be removed from the area and a fire extinguisher shall be provided.

(b) Gas or electric welding or cutting shall not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

(d) No welding or acetylene cutting shall be done on a pipeline, main or auxiliary apparatus that contains air if it is connected to a source of gas, unless a suitable means has been provided to prevent leakage of gas into the pipeline or main.

(e) In situations where welding or cutting must be done on facilities which are filled with air and connected to a source of gas and precautions recommended above cannot be taken, one (1) or more of the following precautions, depending upon circumstances at the job, are required:

1. Purging pipe or equipment upon which welding or cutting is to be done, with combustible gas or inert gas.

2. Testing of the atmosphere in the vicinity of the zone to be heated before work is started and at intervals as the work progresses, with a combustible gas indicator or by other suitable means.

3. Careful verification before work starts that valves that isolate the work from a source of gas do not leak.

(f) When the main is to be separated a bonding conductor shall be installed across the point of separation and maintained while the pipeline is separated. If overhead electric transmission lines parallel the pipeline right-of-way, the current carrying capacity of the bonding conductor should be at least one-half (1/2) of the capacity of the overhead line conductors.

(g) For additional purging procedures see A.G.A. publication "Purging Principals and Practices" (1975 Edition.)

(28) Caulked bell and spigot joints.

(a) Each cast iron caulked bell and spigot joint subject to pressures of twenty-five (25) psig or more shall be sealed with:

1. A mechanical leak clamp; or

2. A material or device which:

a. Does not reduce flexibility of the joint;

b. Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

c. Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of Section 2(2)(a) and (b) and Section 4(2) of this administrative regulation.

(b) Each cast iron caulked bell and spigot joint subject to pressures of less than twenty-five (25) psig and exposed for any reason, shall be sealed by means other than caulking.

(29) Protecting cast iron pipelines. When a utility has knowledge that the support for a segment of a buried cast iron pipeline is disturbed:

(a) That segment of pipeline shall be protected against damage during the disturbance by:

1. Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;
2. Impact forces by vehicles;
3. Earth movement;
4. Apparent future excavations near the pipeline; or
5. Other foreseeable outside forces which may subject that segment of pipeline to bending stress.

(b) As soon as feasible, permanent protection shall be provided for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of subsections (10)(a) and (11) of Section 7 and subsection (6)(b) through (d) of Section 9 of this administrative regulation.

Section 15. Purity of Gas. (1) All gas supplied to customers shall contain no more than: a trace of hydrogen sulfide, thirty (30) grains of total sulphur per 100 cubic feet; or five (5) grains of ammonia per 100 cubic feet. No gas shall contain impurities which may cause excessive corrosion of mains or piping or form corrosive or harmful fumes when burned in a properly designed and adjusted burner.

(2) When necessary, tests for the presence of hydrogen sulfide shall be made at least once each day, except Sundays and holidays, with the standard lead acetate paper method. Results of these test papers shall be properly recorded and filed, as specified by the commission.

(3) Manufactured and mixed gas shall be tested at least once each month for the presence of total sulphur and ammonia, except that any gas containing no coal gas need not be tested for ammonia. Approved methods of testing shall be used. Records of all tests shall be preserved as specified by the commission.

Section 16. Heating Value of Gas. (1) Definitions of heating value. The heating value of gas is the number of British Thermal Units (BTUs) produced by the combustion at constant pressure, of that amount of gas which would occupy a volume of one (1) cubic foot at a temperature of sixty (60) degrees Fahrenheit, if saturated with water vapor and under pressure equivalent to thirty (30) inches of mercury at a temperature of thirty-two (32) degrees Fahrenheit and under gravity, with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of the gas and air, and when the water formed by combustion is condensed to liquid stage.

(2) Each utility shall establish and maintain a standard heating value for its gas. The heating value standard adopted shall comply with the following:

(a) It shall be consistent with good service.

(b) It shall be that value which the utility determines is most practical and economical to supply to its customers.

(3) Each utility shall file with the commission its standard heating value as part of its schedule of Rates, Rules and Regulations.

(4) The utility shall maintain the heating value of the gas with as little variation as practicable, but this variation shall not be more than five (5) percent above or below the established standard heating value.

(5) The heating value standard shall be the monthly average heating value of gas delivered to customers at any point within one (1) mile of the center of distribution, and shall be obtained in the following manner: results of all tests for heating value made on any day during the calendar month shall be averaged, and the average of all such daily averages shall be used in computing the monthly average.

(6) Each utility, selling more than 300,000,000 cubic feet of gas annually, shall maintain a calorimeter, gas chromatograph, or other equipment for testing the hearing value of gas or shall retain the services of a competent testing laboratory approved by the commission. This testing equipment owned by the utility shall be subject to approval of the commission and be made available for testing certification. Utilities served directly from a transmission line shall be exempt from this rule if there is approved equipment for measuring the heating value of gas maintained by the transmission company and if such equipment is available for testing and certification by the commission.

(7) Each utility shall conduct test and maintain necessary records to document that the requirements of this section are being met. Those utilities which bill on the basis of heating value shall, as part of its schedule of Rates, Rules and Regulations, file with the commission the schedule of tests and test procedure(s) it will conduct to determine the heating value of its gas.

(8) Any change in heating value greater than that allowed in subsection (4) of this section shall not be made without approval of the commission and without adequate notice to affected customers. In such event, the utility shall make any adjustments to the customer's appliances without charge and shall conduct the adjustment program with a minimum of inconvenience to the customer.

Section 17. Waste. All practices in the production, distribution, consumption, or use of natural gas which are wasteful are hereby expressly prohibited.

Section 18. Deviations from Rules. In special cases for good cause shown the commission may permit deviations from these rules. (10 Ky.R. 1029; eff. 3-31-84; Am. 16 Ky.R. 1994; eff. 5-13-90.)

APPENDIX A INCORPORATED BY REFERENCE
I. List of Organizations and Addresses.
A. American National Standards Institute (ANSI), 1430 Broadway, New York, N.Y. 10018.
B. American Petroleum Institute (API), 1801 K Street N.W., Washington, D.C. 20006 or 300 Corrigan Tower Building, Dallas, Texas 75201.
C. American Society of Mechanical Engineers (ASME), United Engineering Center, 345 East 47th Street, New York, N.Y. 10017.
D. American Society for Testing and Material (ASTM), 1916 Race Street, Philadelphia, Pa. 19103.
E. Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 5203 Leesburg Pike, Suite 502, Falls Church, Va. 22041.
F. National Fire Protection Association (NFPA), Batterymarch Park, Quincy, Massachusetts 02269.
II. Documents incorporated by reference. Numbers in parenthesis indicate applicable editions.
A. American Petroleum Institute:
(1) API Specification 6D "API Specification for Pipeline Valves" (1977).
(2) API Specification 5L "API Specification for Line Pipe" (1980).
(3) API Recommended Practice 5L1 "API Recommended Practice for Railroad Transportation of Line Pipe" (1972).
(4) API Standard 1104 "Standard for Welding Pipelines and Related Facilities" (17th Edition, 1988).
B. American Society for Testing and Materials:
(1) ASTM Specification A53 "Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated Welded and Seamless" (A53-79).
(2) ASTM Specification A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-79b).
(3) ASTM Specification A671 "Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures" (A671-77).
(4) ASTM Specification A672 "Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (A672-79).
(5) ASTM Specification A691 "Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures" (A169-79).
(6) ASTM Specification A333 "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (A333-79).
(7) ASTM Specification A372 "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels" (A372-78).
(8) ASTM Specification A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for Use with High-Pressure Transmission Systems" (A381-79).

(9) ASTM Specification D638 "Standard Test Method for Tensile Properties of Plastic" (D368-77a).
(10) ASTM Specification D900 "Standard Method Test for Caloric Value of Gaseous Fuels by the Water Flow Calorimeter" (D900-55-1974 Edition).
(11) ASTM Specification D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (D2513-87).
(12) ASTM Specification D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D2517-73) (Reapproved 1979).
C. American National Standards Institute, Inc.:
(1) ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (1975).
(2) ANSI B16.5 "Steel Pipe Flanges and Flanged Fittings" (1977).
D. American Society of Mechanical Engineers:
(1) ASME Boiler and Pressure Code, Section VIII "Pressure Vessels Division I" (1977).
(2) ASME Boiler and Pressure Vessel Code, Section IX "Welding Qualifications" (1977).
E. Manufacturer's Standardization Society of the Valve and Fittings Industry:
(1) MSS SP-44 "Steel Pipe Line Flanges" (1975).
F. National Fire Protection Association:
(1) NFPA Standard 30 "Flammable and Combustible Liquids Code" (1977).
(2) NFPA Standard 54 "National Fuel Gas Code" (1980).
(3) NFPA Standard 58 "Standard for the Storage and Handling of Liquefied Petroleum Gases" (1979).
(4) NFPA Standard 59 "Standards for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants" (1979).
(5) NFPA Standard 59A "Storage and Handling Liquefied Natural Gas" (1979).
(6) "National Electrical Code" NFPA-70 (ANSI) (1978).
G. National Bureau of Standards:
(1) Circular No. 48 "Standard Methods of Gas Testing" (1916).
(2) Research Paper No. 1741 "Testing Large Capacity Rotary Gas Meters," National Bureau of Standards Journal of Research, September, 1946.

APPENDIX B QUALIFICATION OF PIPE	=
I. Listed Pipe Specifications. Numbers in parentheses indicate applicable editions.	=
API 5L - Steel Pipe (1980).	=
ASTM A53 - Steel Pipe (1979).	=
ASTM A106 - Steel Pipe (1979).	=
ASTM A333 - Steel Pipe (1979).	=
ASTM A381 - Steel Pipe (1979).	=
ASTM Specification A671 - Steel Pipe (1977).	=
ASTM Specification A672 - Steel Pipe (1979).	=
ASTM D2513 - Thermoplastic Pipe and Tubing (1987).	=

ASTM D2517 - Thermoplastic Plastic Pipe and Tubing (1973).		=
II. Steel pipe of unknown or unlisted specification.		=
A. Bending Properties. For pipe two (2) inches or less in diameter, a length of pipe shall be cold bent through at least ninety (90) degrees around a cylindrical mandrel that has a diameter twelve (12) times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld. Pipe more than two (2) inches in diameter shall meet the requirements of the flattening test set forth in ASTM A53, except that the number of tests shall be at least equal to the minimum required in paragraph 11-D of this appendix to determine yield strength.		
B. Weldability. A girth weld shall be made in pipe by a welder who is qualified under Subpart E of this part. The weld shall be made under the most severe conditions under which welding will be allowed in the field and by the same procedure that will be used in the field. On pipe more than four (4) inches in diameter, at least one (1) test weld shall be made for each 100 lengths of pipe. On pipe four (4) inches or less in diameter, at least one (1) test weld shall be made for each 400 lengths of pipe. The weld shall be tested in accordance with API Standard 1104. If requirements of API Standard 1104 cannot be met, weldability may be established by making chemical test for carbon and manganese, and proceeding in accordance with Section IX of the ASME Boiler and Pressure Vessel Code. The same number of chemical tests shall be made as are required for testing a girth weld.		=
C. Inspection. Pipe shall be clean enough to permit adequate inspection. It shall be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair strength or tightness of the pipe.		=
D. Tensile Properties. If the pipe's tensile properties are not known, minimum yield strength may be taken as 24,000 psig or less, or tensile properties may be established by performing tensile tests as set forth in API Standard 5LX. All test specimens shall be selected at random and the following number of tests must be performed:		=
NUMBER OF TENSILE TEST - ALL SIZES		=
10 lengths or less ____	1 set of tests for each length.	=
11 lengths to 100 lengths ____	1 set of tests for each 5 lengths, but not less than 10 tests.	=
Over 100 lengths ____	1 set of tests for each 10 lengths, but not less than 10 tests.	=
If the yield-tensile ratio, based on properties determined by those tests, exceeds 0.85, pipe may be used only as provided in 192.55(c).		=
III. Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications. Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in Section 1 of this appendix, is qualified for use under this part if the following requirements are met:		=
A. Inspection. Pipe shall be clean enough for inspection to ensure that it is reasonably round and straight and that there are no defects which might impair strength or tightness of the pipe.		=
B. Similarity of specification requirements. The edition of the listed specification under which pipe was manufactured shall have substantially the same requirements with respect to the following properties as a later edition of that specification listed in Section I of this appendix:		=

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.	=
(2) Chemical properties of pipe and testing requirements to verify those properties.	=
C. Inspection or test of welded pipe. On pipe with welded seams, one (1) of the following requirements shall be met:	=
(1) The edition of the listed specification to which the pipe was manufactured shall have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in Section I of this appendix.	=
(2) Pipe shall be tested in accordance with Subpart J of this part to at least 1.25 times maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least 1.5 times maximum allowable operating pressure if it is to be installed in a Class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Subpart J of this part, test pressure shall be maintained for at least eight (8) hours.	=

APPENDIX C QUALIFICATION OF WELDERS FOR LOW STRESS LEVEL PIPE
I. Basic test. Test shall be made on pipe twelve (12) inches or less in diameter. The test weld shall be made with pipe in horizontal fixed position so that test weld includes at least one (1) section of overhead position welding. Beveling, root opening, and other details shall conform to the specification of the procedure under which the welder is being qualified. Upon completion, test weld shall be cut into four (4) coupons and subjected to a root bend test. If two (2) or more of the four (4) coupons then develop a crack more than 1/8 inch long in any direction in the weld material, or between weld material and base metal, the weld shall be unacceptable. Cracks that occur on the specimen corner during testing are not considered.
II. Additional tests for welders of service line connections to mains. A service line connection fitting shall be welded to a pipe section with the same diameter as a typical main. The weld shall be made in the same position as it is made in the field. The weld shall be unacceptable if it shows a serious undercutting or if it has rolled edges. The weld shall be tested by attempting to break the fitting off the run pipe. The weld shall be unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at junction of the fitting and run pipe.
III. Periodic tests for welders of small service lines. Two (2) samples of the welder's work, each about eight (8) inches long with the weld approximately centered, shall be cut from steel service line and tested as follows:
(1) One (1) sample shall be centered in a guilded bend testing machine and bent to the die contour for two (2) inches on each side of the weld. If the sample shows any break or cracks after removal from the bending machine, it shall be unacceptable.
(2) The ends of the second sample shall be flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld shall be unacceptable. If a tensile strength testing machine is not available, this sample shall also

pass the bending test prescribed in subparagraph (1) of this paragraph.

APPENDIX D CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS
I. Criteria for cathodic protection:
A. Steel, cast iron, and ductile iron structures.
(1) Negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage shall be made with the protective current applied, and in accordance with Sections II and IV of this appendix.
(2) Negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift shall be made with the protective current applied, and in accordance with Sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metal of different anodic potentials.
(3) Minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift shall be determined in accordance with Sections III and IV of this appendix.
(4) Net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.
B. Aluminum structures.
(1) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift shall be determined in accordance with Sections II and IV of this appendix.
(2) Except as provided in paragraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift shall be determined in accordance with Sections III and IV of this appendix.
(3) Notwithstanding the alternative minimum criteria in paragraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with Section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary may suffer corrosion resulting from the buildup of alkali on the metal surface. A voltage in excess of 1.20 volts shall not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.
(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of cathodic protection tends to increase the pH at the metal surface, careful investigation or testing shall be made before applying cathodic protection to stop pitting attach on aluminum structures in environments with a natural pH in excess of eight (8).
C. Copper structures. Minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift shall be determined in accordance with Sections III and IV of this appendix.

D. Metal of different anodic potentials. Negative (cathodic) voltage, measured in accordance with Section IV of this appendix, equal to that required for the most anodic metal in the system shall be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by paragraphs (3) and (4) of paragraph B of this section, they shall be electrically isolated with insulating flanges or their equivalent.
II. Interpretation of voltage measurement. Voltage (IR) drops other than those across the structure-electrolyte boundary shall be considered for valid interpretation of the voltage measurement in paragraphs A(1) and (2) and paragraph B(1) of Section I of this appendix.
III. Determination of polarization voltage shift. Polarization voltage shift shall be determined by interrupting the protective current and measuring polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift shall be used as the base reading from which to measure polarization decay in paragraphs A(3), B(2), and C of Section I of this appendix.
IV. Reference half cells.
A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage shall be measured between the structive surface and a saturated copper-copper sulfate half cell contacting the electrolyte.
B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two (2) commonly used reference half cells are listed below along with their voltage equivalent to -0.85 volt as referred to a saturated copper-copper sulfate half cell:
(1) Saturated KCl calomel half cell: -0.78 volt.
(2) Silver-silver chloride half cell used in sea water: -0.80 volt.
C. In addition to the standard reference half cell, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.