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*Sections of the Code of Federal Regulations to which additions have been made.

* (Italics) New sections that have been added.

Subpart A—General

192.1 Scope of part.

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

(b) This part does not apply to:

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

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

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

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

192.3 Definitions.

As used in this part—

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"Service line" means a distribution line that transports gas from a common source of supply to (1) a customer meter or the connection to a customer's piping, whichever is farther downstream, or (2) the connection to a customer's piping if there is no customer meter. A customer meter is the meter that measures the transfer of gas from an operator to a consumer.

"SMYS" means specified minimum yield strength is—

(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 192.107 (b).

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

"Transmission line" means a pipeline, other than a gathering line, that—

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

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

(3) Transports gas within a storage field.

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

192.5 Class locations.

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

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

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

(d) A Class 3 location is—

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

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

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

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

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

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

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

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

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

192.7 Incorporation by reference.

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

(b) All incorporated documents are available for inspection in the Office of Pipeline Safety, Room 107, 400 Sixth Street SW., Washington, D.C. In addition, the documents are available at the addresses provided in Appendix A to this part.

(c) The full titles for the publications incorporated by reference in this part are provided in Appendix A to this part.

192.9 Gathering lines.

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

192.11 Petroleum gas systems.

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

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

(1) Aboveground structures must have open vents near the floor level.

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

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

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

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

192.12 Liquefied natural gas facilities.

(a) Except for a pipeline facility in operation or under construction before January 1, 1973, no operator may store, treat or transfer liquefied natural gas in a pipeline facility unless that pipeline facility meets the applicable requirements of this part and of NFPA Standard No. 59A.

(b) No operator may store, treat, or transfer liquefied natural gas in a pipeline facility in operation or under construction before January 1, 1973, unless—

(1) The facility is operated in accordance with the applicable operating requirements of this part and of NFPA Standard 59A; and

(2) Each modification or repair made to the facility after December 31, 1972, conforms to the applicable requirements of this part and NFPA Standard 59A, insofar as is practicable.

192.13 General

(a) No person may operate a segment of pipeline that is readied for service after March 12, 1971, or in the case of an offshore gathering line, after July 31, 1977, unless that pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part.

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

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

192.15 Rules of regulatory construction.

(a) As used in this part—

"Includes" means including but not limited to.

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

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

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

(b) In this part—

(1) Words importing the singular include the plural;

(2) Words importing the plural include the singular; and

(3) Words importing the masculine gender include the feminine.

192.17 Filing of inspection and maintenance plans.

(a) Except as provided in paragraph (b) of this section, each operator shall file with the secretary not later than February 1, 1971, a plan for inspection and maintenance of each pipeline facility which he owns or operates. In addition, each change to an inspection and maintenance plan must be filed with the secretary within 20 days after the change is made.

(b) The provisions of paragraph (a) of this section do not apply to pipeline facilities—

(1) That are subject to the jurisdiction of a state agency that has submitted a certification or agreement with respect to those facilities under section 5 of the Natural Gas Pipeline Safety Act (49 U.S.C. 1675); and

(2) For which an inspection and maintenance plan is required to be filed with that state agency.

(c) Plans filed with the secretary must be sent to the office of Pipeline Safety, Department of Transportation, Washington, D.C. 20590.

Subpart B—Materials

192.51 Scope.

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

192.53 General.

Materials for pipe and components must be—

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

PSC 192.53 (a) Some of the materials conforming to specifications approved for use under this code may not have properties suitable for the lower portion of the temperature band covered by this code. Engineers are cautioned to give attention to the low-temperature properties of the materials used for facilities to be exposed to unusually low ground temperatures or low atmospheric temperatures. Twenty (20) inch steel pipe and larger, with a specified minimum yield strength of 52,000 p.s.i. or higher, shall be tested for fracture toughness in accordance with the applicable section of respective API standard under which it was produced, except for small lot purchases of pipe where testing for fracture toughness is impractical.

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

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

PSC 192.53 (d) When substantial quantities of pipe are acquired certified reports of chemical composition and physical properties shall be obtained; when the quantity of pipe involved is so limited that this requirement would be impractical, a certified statement shall be obtained setting forth the specification under which the pipe was manufactured.

192.55 Steel pipe.

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

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

(2) It meets the requirements of—

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

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

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

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

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

(2) It meets the requirements of—

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

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

(3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B to this part; or

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

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

(d) Steel pipe that has not been previously used may be used as replacement pipe in a segment of pipeline if it has been manufactured prior to November 12, 1970, in accordance with the same specification as the pipe used in constructing that segment of pipeline.

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

PSC 192.55 (f) Pipe manufactured from steel made by the Bessemer process shall not be used.

192.57 Cast iron or ductile iron pipe.

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

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

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

(2) It was manufactured in accordance with a listed specification.

PSC 192.57 (c) Cast iron pipe shall not be used as a permanent part of any piping system constructed under this code except where it is used as a temporary installation or replacement of short sections of existing cast iron pipe because of maintenance or relocation. In those cases where cast iron pipe is used it shall be designed, *installed, and operated in accordance with the applicable sections of this code.*

192.59 Plastic pipe.

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

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

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

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

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

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

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

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

(5) It is free of visible defects.

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

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

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

PSC 192.59 (c) *Plastic pipe and tubing shall be adequately supported during storage. Thermoplastic pipe, tubing and fittings shall be protected from long term exposure to direct sunlight.*

192.61 Copper pipe.

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

192.63 Marking of materials.

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

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

(2) MSS standard practice, SP-25.

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

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

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

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

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

192.65 Transportation of pipe.

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

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

(b) In the case of pipe transported before November 12, 1970, the pipe is tested in accordance with Subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location.

Notwithstanding any shorter time period permitted under Subpart J of this part, the test pressure must be maintained for at least 8 hours.

Subpart C—Pipe Design

192.101 Scope.

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

192.103 General.

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

192.105 Design formula for steel pipe.

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

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

P = Design pressure in pounds per square inch gage.

S = Yield strength in pounds per square inch determined in accordance with 192.107.

D = Nominal outside diameter of the pipe in inches.

t = Nominal wall thickness of the pipe in inches. If this is unknown, it is determined in accordance with 192.109.

Additional wall thickness required for concurrent external loads in accordance with 192.103 may not be included in computing design pressure.

F = Design factor determined in accordance with 192.111.

E = Longitudinal joint factor determined in accordance with 192.113.

T = Temperature derating factor determined in accordance with 192.115.

(b) If steel pipe that has been cold worked to meet the SMYS is heated, other than by welding, to 600° F. or more, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section.

192.107 Yield strength (*S*) for steel pipe.

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

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

(1) If the pipe is tensile tested in accordance with section 11-D of Appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

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

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

192.109 Nominal wall thickness (*t*) for steel pipe.

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

(b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gage set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in 192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

192.111 Design factor (*F*) for steel pipe.

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in 192.105 is determined in accordance with the following table:

Class location	*Design factor (F)*
1	0.72
2	0.60
3	0.50
4	0.40

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

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

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

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

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

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

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

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

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

192.113 Longitudinal joint factor (E) for steel pipe.

The longitudinal joint factor to be used in the design formula in 192.105 is determined in accordance with the following table:

Specification	Pipe class	Longitudinal joint factor (E)
ASTM A 53	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	.60
ASTM A 106	Seamless	1.00
ASTM A 134	Electric fusion arc welded	.80
ASTM A 135	Electric resistance welded	1.00

ASTM A 139	Electric fusion welded	.80
ASTM A 155	Electric fusion arc welded	1.00
ASTM A 211	Spiral welded steel pipe	.80
ASTM A 333	Seamless	1.00
	Electric resistance welded	1.00
ASTM A 381	Double submerged arc welded	1.00
API 5 L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	.60
	Furnace lap-welded	.80
API 5 LX	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
API 5 LS	Electric resistance welded	1.00
	Submerged arc welded	1.00
Other	Pipe over 4 inches	.80
Other	Pipe 4 inches or less	.60

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

192.115 Temperature derating factor (T) for steel pipe.

The temperature derating factor to be used in the design formula in 192.105 is determined as follows:

Gas temperature in degrees Fahrenheit	*Temperature derating factor (T)*
250 or less	1.000
300	0.967
350	0.933
400	0.900
450	0.867

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

192.117 Design of cast iron pipe.

Cast iron pipe must be designed in accordance with ANSI A 21.1 using the following values for *S* (bursting tensile strength) and *R* (modulus of rupture) in the design equations:

Specification	Type of pipe	S	R
		psi	psi
ANSI A 21.3	Pit cast	11,000	31,000
ANSI A 21.7	Centrifugal (metal mold)	18,000	40,000
ANSI A 21.9	Centrifugal (sand-lined mold)	18,000	40,000

192.119 Design of ductile iron pipe.

(a) Ductile iron pipe must be designed in accordance with ANSI A21.50 using the following values in the design equations:
s (design hoop stress) = 16,800 p.s.i.
f (design bending stress) = 36,000 p.s.i.

(b) Ductile iron pipe must be grade (60-42-10) and must conform to the requirements of ANSI A21.52.

192.121 Design of plastic pipe.

(a) The design pressure for plastic pipe is determined in accordance with the following formula and is subject to the limitations of 192.123:

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

P = Design pressure in pounds per square inch gage.
S = For thermoplastic pipe, the long-term hydrostatic strength in pounds per square inch as stated in the listed specification; for thermosetting plastic pipe, 11,000 p.s.i.
t = Specified wall thickness in inches.
D = Specified outside diameter in inches.
F = Design factor for plastic pipe.

(b) The design factor for plastic pipe is determined as follows:

Class location	*Design factor*
1	*0.32*
2	*0.25*
3	*0.25*
4	*0.20*

192.123 Design limitation for plastic pipe.

(a) The design pressure may not exceed 100 p.s.i.g. for plastic pipe used in—

(1) Distribution systems; or

(2) Classes 3 and 4 locations.

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

(1) Below minus 20° F.; or

(2) Above 100° F. for thermoplastic pipe or above 150° F. for reinforced thermosetting plastic pipe.

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

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

Nominal size in inches	*Minimal wall thickness in inches*
2	0.060
3	0.060
4	0.070
6	0.100

192.125 Design of copper pipe.

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

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

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

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

PSC 192.125 (e) Fittings in copper piping. It is recommended that fittings in copper piping and exposed to the soil, such as service tees, pressure control fittings, etc., be made of bronze, copper or brass.

Subpart D—Design of Pipeline Components

192.141 Scope.

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

192.143 General Requirements.

Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service.

192.145 Valves.

(a) Each valve must meet the minimum requirements, or the equivalent, of API 6A, API 6D, MSS SP-70, MSS SP-71, or MSS SP-78, except that a valve designed before July 1, 1976, may meet the minimum requirements of MSS SP-52. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those standards.

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

(c) No valve having shell components made of ductile iron may be used at pressures exceeding 80% of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80% of the pressure ratings for comparable steel valves at their listed temperature, if—

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

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

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

192.147 Flanges and flange accessories.

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

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

192.149 Standard fittings.

(a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.

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

192.151 Tapping.

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

(b) Where a ductile iron pipe is tapped, the extent of full-thread engagement and the need for the use of outside-sealing service connections, tapping saddles, or other fixtures must be determined by service conditions.

(c) Where a threaded tap is made in cast iron or ductile iron pipe, the diameter of the tapped hole may not be more that 25% 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 1¼-inch tap may be made in a 4-inch cast iron or ductile iron pipe, without reinforcement.

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

192.153 Components fabricated by welding.

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

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

(1) Regularly manufactured butt-welding fittings.

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

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

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

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

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

192.155 Welded branch connections.

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

192.157 Extruded outlets.

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

192.159 Flexibility.

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

192.161 Supports and anchors.

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

(1) Prevent undue strain on connected equipment;

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

(3) Prevent or damp out excessive vibration.

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

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

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

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

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

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

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

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

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

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

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

192.163 Compressor stations: design and construction.

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

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

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

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

PSC 192.163 *(b) All compressor station buildings shall be constructed of non-combustible materials as defined by the Wisconsin state building code administered by the department of industry, labor and human relations.*

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

PSC 192.163 *(c) Exits shall be provided in compliance with the requirements of the Wisconsin state building code administered by* *the department of industry, labor and human relations. Ladders shall not be used for exits.*

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

(e) *Electrical facilities.* Electrical equipment and wiring installed in compressor stations must conform to the National Electrical Code, ANSI Standard C1, so far as that code is applicable.

PSC 192.163 *(e) All electrical equipment and wiring installed in gas transmission and distribution compressor stations shall conform to the requirements of the Wisconsin state electrical code.*

192.165 Compressor stations: liquid removal.

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

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

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

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

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

192.167 Compressor stations: emergency shutdown.

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

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

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

(3) It must provide means for the shutdown of gas compressing equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except, that—

(i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and

(ii) Electrical circuits needed to protect equipment from damage may remain energized.

(4) It must be operable from at least 2 locations, each of which is—

(i) Outside the gas area of the station;

(ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and

(iii) Not more than 500 feet from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

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

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

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

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

(2) In the case of compressor station in a building—

(i) When an uncontrolled fire occurs in the building; or

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

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

192.169 Compressor stations: pressure limiting devices.

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

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

192.171 Compressor stations: additional safety equipment.

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

PSC 192.171 (a) Fire protection. *Fire-protection facilities shall be provided as specifically directed by the department of industry, labor and human relations and the local fire department. The operation of fire-protection facilities, such as pumps, shall not be affected by an emergency shutdown.*

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

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

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

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

192.173 Compressor stations: ventilation.

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

PSC 192.173 *There shall be compliance with the department of industry, labor and human relations' heating, ventilation, and air conditioning code.*

192.175 Pipe-type and bottle-type holders.

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

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

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

in which:

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

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

P=Maximum allowable operating pressure, p.s.i.g.

F=Design factor as set forth in 192.111 of this part.

192.177 Additional provisions for bottle-type holders.

(a) Each bottle-type holder must be—

(1) Located on a storage site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	*Minimum clearance (feet)*
Less than 1,000 p.s.i.g.	25

1,000 p.s.i.g. or more	100

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

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

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

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

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

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

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

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

192.179 Transmission line valves.

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

(1) Each point on the pipeline in a Class 4 location must be within 2½ miles of a valve.

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

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles of a valve.

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

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

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

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

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

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

192.181 Distribution line valves.

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

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

PSC 192.181 *(b) It is intended that the distance between the valve and the regulator or regulators shall be sufficient to permit the operation of the valve during an emergency such as a large gas leak or a fire in the station. These valves shall be in accessible locations not closer than 25 feet and preferably not more than 1,500 feet distant from each regulator station.*

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

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

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

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

192.183 Vaults: structural design requirements.

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

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

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

PSC 192.183 *(d) In the design of vaults and pits for pressure limiting, pressure relieving and pressure regulating equipment, consideration shall be given to the protection of the installed equipment from damage, such as that resulting from an explosion within the vault or pit, which may cause portions of the roof or cover to fall into the vault.*

PSC 192.183 *(e) Vault or pit openings shall be located so as to minimize the hazards of tools or other objects falling upon the regulator, piping, or other equipment. The control piping and the operating parts of the equipment installed shall not be located under* *a vault or pit opening where workmen can step on them when entering or leaving*

192.203 Instrument, control, and sampling pipe and components.

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

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

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

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

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

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

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

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

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

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

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

PSC 192.204 Pipelines on private right-of-way of electric transmission lines.

Where gas pipelines parallel overhead electric transmission lines on the same right-of-way, the company operating the pipelines shall take the following precautions:

(a) Employ blow-down connections that will direct the gas away from the electric conductors.

(b) Install a bonding conductor across points where the main is to be separated and maintain this connection while the pipeline is separated. The current carrying capacity of the bonding conductor should be at least one-half of the capacity of the overhead line conductors.

(c) Make a study in collaboration with the electric company on the common problems of corrosion and electrolysis, taking the following factors into consideration:

(1) The possibility of the pipeline carrying either unbalanced line currents or fault currents.

(2) The 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 the buried ground facilities or the ground-wire of the overhead electric system.

(d) Investigate the necessity of protecting insulating joints in the pipeline against induced voltages or currents resulting from lightning strokes. Such protection can be obtained by connecting buried sacrificial anodes to the pipe near the insulating joints or by bridging the pipeline insulator with a spark-gap or by other effective means.

Subpart E—Welding of Steel in Pipelines

192.221 Scope.

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

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

192.223 General.

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

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

PSC 192.223 (c) *Prior to welding in or around a structure or area containing gas facilities, a thorough check shall be made to determine the possible presence of a combustible gas mixture. Welding shall begin only when safe conditions are indicated.*

192.225 Qualifications of welding procedures.

(a) Each welding procedure must be qualified under section IX of the 1974 edition of the ASME Boiler and Pressure Vessel Code or section 2 of the 1973 edition of API Standard 1104, whichever is appropriate to the function of the weld, except that a welding procedure qualified under section IX of the 1963 edition of the ASME Boiler and Pressure Vessel Code before July 1, 1976, or section 2 of the 1968 edition of API Standard 1104 before March 20, 1975, may continue to be used but may not be requalified under that edition.

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

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

(2) Carbon steels that have a carbon equivalent (C+¼ Mn) of 0.65 percent (ladle analysis) or less.

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

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

192.227 Qualification of welders.

(a) Except as provided in paragraph (c) of this section, each welder must be qualified in accordance with one of the following:

(1) Section IX of the 1974 edition of the ASME Boiler and Pressure Vessel Code or, if qualified before July 1, 1976, the 1968 edition, except that a welder may not requalify under the 1968 edition.

(2) The following editions of Section 3 of API Standard 1104:

(i) The 1973 edition, except, that a welder may be qualified by radiography under subsection 3.51 without regard for the standards in subsection 6.9 for depth of undercutting adjacent to the root bead unless that depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld, or

(ii) If a welder is qualified before March 20, 1975, the 1968 edition, except that a welder may not requalify under the 1968 edition.

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

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

(2) Carbon steels that have a carbon equivalent (C+¼ Mn) of 0.65 percent (ladle analysis) or less.

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

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

(1) Within the preceding 12 calendar months, he has requalified; or

(2) Within the preceding 6 calendar months he has had—

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

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

192.229 Limitations on welders.

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

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

(c) A welder qualified under section 192.227 (a) may not weld unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under—

(1) Section 3 or 6 of the 1973 edition of API Standard 1104, except for the standards in subsection 6.9 for depth of undercutting adjacent to the root bead unless that depth is visually determined by use of a depth measuring device on all undercutting along the entire circumference of the weld; or

(2) In the case of tests conducted before March 20, 1975, section 3 or 6 of the 1968 edition of API Standard 1104.

192.231 Protection from weather.

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

192.233 Miter joints.

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

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30%, but more than 10%, of SMYS may not deflect the pipe more than 12½° and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

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

192.235 Preparation for welding.

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

192.237 Preheating.

(a) Carbon steel that has a carbon content in excess of 0.32 percent (ladle analysis) or a carbon equivalent (C+¼ Mn) in excess of 0.65 percent (ladle analysis) must be preheated for welding.

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

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

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

192.239 Stress relieving.

(a) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content in excess of 0.32 percent (ladle analysis) or a carbon equivalent (C+¼ Mn) in excess of 0.65 percent (ladle analysis) must be stress relieved as prescribed in section VIII of the ASME Boiler and Pressure Vessel Code.

(b) Except as provided in paragraph (f) of this section, each weld on carbon steel that has a carbon content of less than 0.32 percent (ladle analysis) or a carbon equivalent (C+¼ Mn) of less than 0.65 percent (ladle analysis) must be thermally stress relieved when conditions exist which cool the weld at a rate detrimental to the quality of the weld.

(c) Except as provided in paragraph (f) of this section, each weld on carbon steel pipe with a wall thickness of more than 1¼ inches must be stress relieved.

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

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

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

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

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

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

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

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

(h) When stress relieving, the temperature must be monitored to ensure that a uniform temperature is maintained and that the proper stress relieving cycle is accomplished.

192.241 Inspection and test of welds.

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

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

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

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

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

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

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in Section 6 of the 1973 edition of API Standard 1104. However, the standards in subsection 6.9 for depth of undercutting adjacent to the root bead apply only if—

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

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

192.243 Nondestructive testing.

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

(b) Nondestructive testing of welds must be performed—

(1) In accordance with written procedures; and

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

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

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

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

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

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

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

PSC 192.243 *(d) (5) In addition, all welds within 500 feet of buildings intended for human occupancy shall be tested.*

PSC 192.243 *(d) (6) If one weld in any random sample is found to be unacceptable then the minimum percentage of welds selected for examination will be that of the next higher class location. If a second weld is found to be unacceptable or if 2 or more welds are found to be unacceptable in the original random sample, then 100% of the welds shall be inspected if practicable, but in no case less than 90% of the welds in that day's construction.*

(e) Except for a welder whose work is isolated from the principal welding activity, a sample of each welder's work for each day must be nondestructively tested, when nondestructive testing is required under 192.241 (b).

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

192.245 Repair or removal of defects.

(a) Each weld that is unacceptable under 192.241 (c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipelay vessel, a weld must be removed if it has a crack that is more than 2 inches long or that penetrates either the root or second bead.

(b) Each weld that is repaired must have the defect removed down to clean metal and the segment to be repaired must be preheated. After repair, the segment of the weld that was repaired must be inspected to insure its acceptability. If the repair is not acceptable, the weld must be removed, except that additional repairs made in accordance with written welding procedures qualified under 192.225 are permitted for welds on an offshore pipeline being installed from a pipelay vessel.

PSC 192.246 Precautions to avoid explosions of gas-air mixtures or uncontrolled fires during construction operations.

(a) Operations such as gas or electric welding and cutting with cutting torches can be safely performed on pipelines and mains and auxiliary equipment, provided that they are completely full of gas, or air that is free from combustible material. Steps shall be taken to prevent a mixture of gas and air at all points where such operations are to be performed.

(b) When a pipeline or main can be kept full of gas during a welding or cutting operation, the following procedures are recommended:

(1) Keep a slight flow of gas moving toward the point where cutting or welding is being done.

(2) The gas pressure at the site of the work shall be controlled by suitable means.

(3) Close all slots or open ends immediately after they are cut with tape, and/or tightly fitting canvas or other suitable material.

(4) Do not permit two openings to remain uncovered at the same time. This is doubly important if the two openings are at different elevations.

(c) 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 the leakage of gas into the pipeline or mains.

(d) In situations where welding or cutting must be done on facilities which are filled with air and connected to a source of gas and the precautions recommended above cannot be taken, one or more of the following precautions, depending upon the circumstances at the job are required:

(1) Purging of the 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 the work is started and at intervals as the work progresses, with a combustible gas indicator or by other suitable means.

(3) Careful verification before the work starts that the valves that isolate the work from a source of gas do not leak.

Subpart F—Joining of Materials Other Than by Welding

192.271 Scope.

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

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

192.273 General.

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

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

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

192.275 Cast iron pipe.

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

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

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

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

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

192.277 Ductile iron pipe.

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

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

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

192.279 Copper pipe.

Copper pipe may not be threaded, except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of standard wall pipe, as defined in ANSI Standard B36.10.

PSC 192.279

Copper pipe shall be joined by using either a compression type coupling or a brazed or soldered lap joint. The filler material used for brazing shall be a copper-phosphorous alloy or silver base alloy. Butt welds are not permissible for joining copper pipe or tubing.

192.281 Plastic pipe.

(a) *General.* Each plastic pipe joint must be made in accordance with written procedures that have been proven by destructive burst test to produce joints at least as strong as the pipe being joined. A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

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

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

(2) The solvent cement must conform to ASTM Specification D 2513.

(3) The safety requirements of Appendix A of ASTM Specification D 2513 must be met.

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

PSC 192.281 (b) (5) *Proper fit between the pipe or tubing and mating socket or sleeve is essential to a good joint. Sound joints cannot normally be made between loose fitting parts.*

PSC 192.281 (b) (6) *A uniform coating of the solvent cement is required on both mating surfaces. After the joint is made, excess cement shall be removed from the outside of the joint. The joint shall not be disturbed until it has properly set.*

PSC 192.281 (b) (7) *This type joint shall not be made between different kinds of plastics.*

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

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

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

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

PSC 192.281 (c) (4) *Care must be used in the heating operation to prevent damage to the plastic material from overheating or having the material not sufficiently heated to assure a sound joint.*

PSC 192.281 (c) (5) *This type joint shall not be made between different kinds of plastics.*

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

(1) The adhesive must conform to ASTM Specification D 2517.

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

PSC 192.281 (d) (3) *An adhesive bonded joint may be heated in accordance with the pipe manufacturer's recommendation in order to accelerate cure.*

PSC 192.281 (d) (4) *Provision shall be made to clamp or otherwise prevent the joined materials from moving until the adhesive is properly set.*

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

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

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

PSC 192.281 (e) (2) *The tubular stiffener should be flush with end of pipe or tubing and project at least 1/2 in. beyond the outside end of the compression fitting when installed. The stiffener shall be free of rough or sharp edges and shall not be a force fit in the plastic.*

Subpart G—General Construction Requirements for Transmission Lines and Mains

192.301 Scope.

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

192.303 Compliance with specifications or standards.

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

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

192.307 Inspection of materials.

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

PSC 192.307 Detection of gouges and grooves.

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

192.309 Repair of steel pipe.

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

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

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

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

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

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

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

(i) More than one-quarter inch in pipe 12 ¾ inches or less in outer diameter; or

(ii) More than 2% of the nominal pipe diameter in pipe over 12 ¾ inches in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

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

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

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

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

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

PSC 192.309 (f) *Due primarily to climate conditions, gouges, grooves, notches, and dents have been found to be an important cause of steel pipe failures and an attempt shall be made to prevent or eliminate harmful defects of this nature. Subsection 192.309 (b) pertains to transmission lines and mains intended to operate at hoop stresses of 20% or 40% or more of the specified minimum yield strength. However, applicable portions of these paragraphs should also be applied to facilities intended to operate below this hoop stress level.*

192.311 Repair of plastic pipe.

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

192.313 Bends and elbows.

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

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

(2) For pipe more than 4 inches in nominal diameter, the difference between the maximum and minimum diameter at a bend must not be more than 2½ percent of the nominal diameter.

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

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

(b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be non-destructively tested either before or after the bending process.

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

(Sec. 3, Pub. L. 90-481, 82 Stat. 721, 49 USC 1672; 40 FR 43901, 49 CFR 1.53).

PSC 192.313 *(a) (5) Smooth bends on pipe 4 inches in size and smaller shall have a difference between the maximum and minimum diameter of not more than 12.5 percent of the nominal diameter.*

(b) Each circumferential weld of steel pipe that is subjected to stress during bending must be nondestructively tested.

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

(d) Each bend, other than a wrinkle bend made in accordance with 192.315, must have a smooth contour and be free of mechanical damage.

192.315 Wrinkle bends in steel pipe.

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

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

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

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

(3) On pipe 16 inches or larger in diameter, the bend may not have a deflection of more than 1½° for each wrinkle.

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

192.317 Protection from hazards.

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

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

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

192.319 Installation of pipe in a ditch.

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

PSC 192.319 *(a) This includes grading the ditch so that the pipe has a firm, substantially continuous bearing on the bottom of the ditch. When long sections of pipe that have been welded alongside the ditch are lowered in, care shall be exercised so as not to jerk the pipe or impose any strains that may kink or put a permanent bend in the pipe.*

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

(1) Provides firm support under the pipe; and

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

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

PSC 192.319 *(b) (3) If there are large rocks in the material to be used for backfill, care should be used to prevent damage to the coating or pipe by such means as the use of rock shield material, or by making the initial fill with rock free material to a sufficient depth over the pipe to prevent rock damage.*

PSC 192.319 *(b) (4) Where flooding of the trench is done to consolidate the backfill, care shall be exercised to see that the pipe is not floated from its firm bearing on the trench bottom.*

PSC 192.319 *(c) The provisions of 192.319 (a) shall also apply to mains operating at less than 20% of the SMYS.*

192.321 Installation of plastic pipe.

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

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

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

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

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

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

PSC 192.321 *(f) The casing pipe shall be reamed and cleaned to the extent necessary to remove any sharp edges, projections, or abrasive material which could damage the plastic during and after insertion. That portion of the plastic piping which spans disturbed earth shall be adequately protected by a bridging piece or other means from crushing or shearing from external loading or settling of backfill. Care shall be taken to prevent the plastic piping from bearing on the end of the casing.*

PSC 192.321 *(g) Care shall be exercised to avoid rough handling of plastic pipe and tubing. It shall not be pushed or pulled over sharp projections, dropped or have other objects dropped upon it. Caution shall be taken to prevent kinking or buckling, and any kinks or buckles which occur shall be removed by cutting out as a cylinder.*

PSC 192.321 *(h) Changes in direction of plastic piping may be made with bends, tees or elbows under the following limitations:*

(1) Plastic pipe and tubing may be deflected to a radius not less than the minimum recommended by the manufacturer for the kind, type, grade, wall thickness and diameter of the particular plastic used.

(2) The bends shall be free of buckles, cracks, or other evidence of damage.

(3) Changes in direction that cannot be made in accordance with PSC 192.321 (h) (1) above shall be made with elbow-type fittings.

(4) Miter bends are not permitted.

(5) Branch connections shall be made only with socket-type tees or other suitable fittings specifically designed for the purpose.

PSC 192.321 *(i) Plastic piping shall be laid on undisturbed or well compacted soil. If plastic piping is to be laid in soils which may damage it, the piping shall be protected by suitable rock free materials before back-filling is completed. Plastic piping shall not be supported by blocking. Well tampered earth or other continuous support shall be used.*

192.323 Casing.

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

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

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

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

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

PSC 192.323 *(e) Casing requirements of highway authorities shall be followed; however, construction type shall not be any less than provided by this code.*

192.325 Underground clearance.

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

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

PSC192.325 *(b) If the structure is a public building where people assemble or in areas such as playground, assembly ground, or park, wherever possible the clearance shall be at least 100 feet if the main is operated at more than 100 p.s.i. but less than 500 p.s.i. and shall be at least 150 feet if operated at 500 p.s.i. or more. If these clearances cannot be maintained, then the next higher type of construction shall be used except such construction may be pressure-tested the same as the remainder of the line. No distribution main or transmission line shall be installed under buildings.*

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

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

192.327 Cover.

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

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

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

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

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

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

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

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

(e) All pipe which is installed in a navigable river, stream, or harbor must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock, and all pipe installed in any offshore location under water less than 12 feet deep, as measured from mean low tide, must have a minimum cover of 36 inches in soil or 18 inches in consolidated rock, between the top of the pipe and the natural bottom. However, less than the minimum cover is permitted in accordance with paragraph (c) of this section.

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

192.351 Scope.

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

192.353 Customer meters and regulators: location.

(a) Each meter and service regulator, whether inside or outside of a building, must be installed in a readily accessible location and be protected from corrosion and other damage. However, the upstream regulator in a series may be buried.

Subpart I—Requirements for Corrosion Control

192.451 Scope.

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

(b) Notwithstanding the deadlines for compliance in this subpart, the corrosion control requirements of this subpart do not apply to offshore gathering lines until August 1, 1977.

192.453 General.

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

192.455 External corrosion control: buried or submerged pipelines installed after July 31, 1971.

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

(1) It must have an external protective coating meeting the requirements of 192.46.

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

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion, accelerating bacteria, that a corrosive environment does not exist. However, within 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 20 feet, and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a) (2) of this section.

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

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

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

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

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

192.457 External corrosion control: buried or submerged pipelines installed before August 1, 1971.

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must, not later than August 1, 1974, be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

(b) Except for cast iron or ductile iron, each of the following buried or submerged pipelines installed before August 1, 1971, must, not later than August 1, 1976, be cathodically protected in accordance with this subpart in areas in which active corrosion is found:

(1) Bare or ineffectively coated transmission lines.

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

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

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

PSC 192.457 (d) Notwithstanding the provisions of 192.457 (b) (regarding active corrosion), effectively coated steel distribution pipelines, except for those portions including services and short sections that because of their nature and installation make cathodic protection impractical and uneconomical, must, not later than August 1, 1976, be cathodically protected along the entire area that is effectively coated in accordance with this subpart.

192.459 External corrosion control: examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion is found, remedial action must be taken to the extent required by 192.483 and the applicable paragraphs of 192.485, 192.487, or 192.489.

192.461 External corrosion control: protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must—

(1) Be applied on a properly prepared surface;

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

(3) Be sufficiently ductile to resist cracking;

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

(5) Have properties compatible with any supplemental cathodic protection.

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

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

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

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

192.463 External corrosion control: cathodic protection.

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

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

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

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

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

192.465 External corrosion control: monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for separately protected service lines or short sections of protected mains, not in excess of 100 feet, these service lines and mains may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system, must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) At intervals not exceeding 2 months, each cathodic protection rectifier or other impressed current power source must be inspected to ensure that it is operating.

(c) At intervals not exeeding 2 months, each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection, must be electrically checked for proper performance. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

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

(e) After the initial evaluation required by paragraphs (b) and (c) of 192.455 and paragraph (b) of 192.457, each operator shall, at intervals not exceeding 3 years, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

192.467 External corrosion control: electrical isolation.

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

(b) An insulating device must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

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

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

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

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

192.469 External corrosion control: test stations.

Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurements to determine the adequacy of cathodic protection.

192.471 External corrosion control: test leads.

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

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

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

192.473 External corrosion control: interference currents.

(a) After July 31, 1973, each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

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

192.475 Internal corrosion control: general.

(a) After July 31, 1972, corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion.

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

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion;

(2) Replacement must be made to the extent required by the applicable paragraphs of 192.485, 192.487 or 192.489; and

(3) Steps must be taken to minimize the internal corrosion.

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

192.477 Internal corrosion control: monitoring.

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. After July 31, 1972, each coupon or other means of monitoring internal corrosion must be checked at intervals not exceeding 6 months.

192.479 Atmospheric corrosion control: general.

(a) *Pipelines installed after July 31, 1971.* Each aboveground pipeline or portion of a pipeline installed after July 31, 1971 that is exposed to the atmosphere must be cleaned and either coated or jacketed with a material suitable for the prevention of atmospheric corrosion. An operator need not comply with this paragraph, 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.* Not later than August 1, 1974, each operator having an aboveground pipeline or portion of a pipeline installed before August 1, 1971 that is exposed to the atmosphere, shall—

(1) Determine the areas of atmospheric corrosion on the pipeline;

(2) If atmospheric corrosion is found, take remedial measures to the extent required by the applicable paragraphs of 192.485, 192.487, or 192.489; and

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

§ 192.481 Atmospheric corrosion control: monitoring.

After meeting the requirements of § § 192.479 (a) and (b), each operator shall, at intervals not exceeding 3 years for onshore pipelines and 1 year for offshore pipelines, reevaluate each pipeline that is exposed to the atmosphere and take remedial action whenever necessary to maintain protection against atmospheric corrosion.

192.483 Remedial measures: general.

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

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

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

192.485 Remedial measures: transmission lines.

(a) *General corrosion.* Each segment of transmission line pipe with general corrosion and with a remaining wall thickness less than that required for the maximum allowable operating pressure of the pipeline, must be replaced or the operating pressure reduced commensurate with the actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

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

192.487 Remedial measures: distribution lines other than cast iron or ductile iron lines.

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

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

192.611 Change in class location; confirmation or revision of maximum allowable operating pressure.

If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised as follows:

(a) If the segment involved has been previously tested in place to at least 90% of its SMYS for a period of not less than 8 hours, the maximum allowable operating pressure must be confirmed or reduced so that the corresponding hoop stress will not exceed 72% of SMYS of the pipe in Class 2 locations, 60% of SMYS in Class 3 locations, or 50% of SMYS in Class 4 locations.

(b) If the segment involved has not been previously tested in place as described in paragraph (a) of this section, the maximum allowable operating pressure must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(c) If the segment of pipeline involved has not been qualified for operation under paragraph (a) or (b) of this section, it must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established so as to be equal to or less than the following:

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

(2) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision.

(3) The corresponding hoop stress may not exceed 72% of the SMYS of the pipe in Class 2 locations, 60% of SMYS in Class 3 locations, or 50% of the SMYS in Class 4 locations.

(d) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of 192.553 and 192.555.

(e) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under 192.609 must be completed as follows:

(1) Confirmation or revision due to changes in class location that occur before July 1, 1973, must be completed not later than December 31, 1974.

(2) Confirmation or revision due to changes in class location that occur on or after July 1, 1973, must be completed within 18 months of the change in class location.

192.613 Continuing surveillance.

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

(b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with 192.619 (a) and (b).

PSC 192.613 *(c) When street is paved or repaved. Whenever a road or street is paved or repaved with permanent pavement, the operator shall:*

(1) Check for leaks along all mains and services in the streets and abutting property. The check shall be conducted by testing with a combustible gas indicator air samples taken from holes placed near the pipes. The utility may substitute for bar hole tests a ground surface survey with a continuous-sampling instrument capable of detecting combustible gas in air concentrations of 100 parts per million.

(2) Determine condition of pipe and joints by sample visual examination.

(3) Place clamps on, reconstruct, or repair joints if they are likely to dry out or are leaking.

(4) Replace pipe if existing pipe is corroded to such an extent that it is likely to require replacement before the street is again resurfaced.

PSC 192.613 (d) Underground pipes. Whenever underground pipes are exposed in order to repair leaks, the utility shall record on the repair order the nature of the leak and possible cause from observation.

PSC 192.615 Emergency plans. (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

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

(9) Safely restoring any service outage.

(10) Beginning action under 192.617, if applicable, as soon after the end of the emergency as possible.

(b) Each operator shall—

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

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to—

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and

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

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

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

192.619 Maximum allowable operating pressure: steel or plastic pipelines.

(a) Except as provided in paragraph (c) of this section, no person may operate a segment of steel or plastic pipeline at a pressure that exceeds the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

PSC 192.619 *(a) (2) (i) For plastic pipe used as a gas service, the maximum allowable operating pressure in any class location shall not exceed 60 p.s.i.g.*

(ii) For steel pipe, operated at 100 p.s.i.g. or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors*	
	Segment installed before (Nov. 12, 1970)	Segment installed after (Nov. 11, 1970)
1	1.1	1.1
2	1.25	1.25
3	1.4	1.5
4	1.4	1.5

* For offshore segments installed or uprated after July 31, 1977, that are not located on a platform the factor is 1.25. For segments installed or uprated after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe risor, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, (or in the case of offshore gathering lines, July 1, 1976) unless the segment was tested in accordance with paragraph (a) (2) of this section after July 1, 1965, (or in the case of offshore gathering lines, July 1, 1976) or the segment was uprated in accordance with Subpart K of this part.

(4) For furnace butt welded steel pipe, a pressure equal to 60% of the mill test pressure to which the pipe was subjected.

(5) For steel pipe other than furnace butt welded pipe, a pressure equal to 85% of the highest test pressure to which the pipe has been subjected, whether by mill test or by the post installation test.

(6) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a) (6) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with 192.195.

(c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, or in the case of offshore gathering lines, July 1, 1976, subject to the requirements of 192.611.

192.621 Maximum allowable operating pressure: high-pressure distribution systems.

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.

(2) Sixty p.s.i.g., for a segment of a distribution system otherwise designed to operate at over 60 p.s.i.g., unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of 192.197 (c).

(3) Twenty-five p.s.i.g. in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

PSC 192.621 *(a) (3) No person may operate a segment of a cast iron pipe in which there are unreinforced bell and spigot joints at a pressure higher than low pressure unless it can be proven to the commission that they can be operated at a higher pressure. However, the maximum allowable operating pressure under any circumstances shall not exceed 15 p.s.i.g.*

(4) The pressure limits to which a joint could be subjected without the possibility of its parting.

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a) (5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with 192.195.

PSC 192.621 *(c) Sixty p.s.i.g. in individual distribution systems or portions thereof. The intercity or supply mains for these distribution systems may be operated at higher pressures provided by this code if the number of services supplied from these mains are limited and these mains are not an integral part of the distribution system. The pressure and the services supplied from these higher pressure intercity and supply mains shall be limited to 60 p.s.i.g. unless the service lines are equipped with series regulators or other pressure limiting devices as prescribed in 192.197 (c)*

192.623 Maximum and minimum allowable operating pressure: low-pressure distribution systems.

(a) No person may operate a low-pressure distribution system at a pressure high enough to make unsafe the operation of any connected and properly adjusted low-pressure gas burning equipment.

(b) No person may operate a low pressure distribution system at a pressure lower than the minimum pressure at which the safe and continuing operation of any connected and properly adjusted low-pressure gas burning equipment can be assured.

PSC 192.623 *(c) No person may operate a low pressure distribution system at a pressure in excess of that provided by section PSC 134.23 (1).*

192.625 Odorization of gas.

(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.

(b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless—

(1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;

(2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;

(i) An underground storage field;

(ii) A gas processing plant;

(iii) A gas dehydration plant; or

(iv) An industrial plant using gas in a process where the presence of an odorant—

(A) Makes the end product unfit for the purpose of which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction; or

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location.

(c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

(1) The odorant may not be deleterious to persons, materials, or pipe.

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

(d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) Each operator shall conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section.

(g) The odorization requirements of Part 190 of this chapter, as in effect on August 12, 1970, must be complied with, in each State in which odorization of gas in transmission lines is required by that part, until the earlier of the following dates:

(1) January 1, 1977; or

(2) The date upon which the distribution companies in that State are odorizing gas in accordance with paragraphs (a) through (f) of this section.

192.627 Tapping pipelines under pressure.

Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

192.629 Purging of pipelines.

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

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

PSC 192.629 (c) No pipeline, main, or service shall be purged into any building or confined space.

Subpart M—Maintenance

192.701 Scope.

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

192.703 General.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.

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

(c) Hazardous leaks must be repaired promptly.

192.705 Transmission lines: patrolling.

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

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

Class location of line	Maximum intervals between patrols	
	At highway and railroad crossings	At all other places
1, 2	6 months	1 year
3	3 months	6 months
4	do	3 months

192.706 Transmission lines; leakage surveys.

(a) Each operator of a transmission line shall provide for periodic leakage surveys of the line in its operating and maintenance plan.

(b) Leakage surveys of a transmission line must be conducted at intervals not exceeding 1 year. However, in the case of a transmission line which transports gas in conformity with section 192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted—

(1) In Class 3 locations, at intervals not exceeding 6 months; and

(2) In Class 4 locations, at intervals not exceeding 3 months.

192.707 Line markers for mains and transmission lines.

(a) *Buried pipelines.* Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line—

(1) At each crossing of a public road, railroad, and navigable waterway; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

However, until January 1, 1978, paragraphs (a) (l) and (a) (2) of this section do not apply to mains installed before April 21, 1975, and until January 1, 1978, paragraph (a) (l) of this section does not apply to transmission lines installed before April 21, 1975.

(b) *Exceptions for buried pipelines.* Line markers are not required for buried mains and transmission lines—

(1) Located offshore or under inland navigable waters;

(2) In Class 3 or Class 4 locations—

(i) Where placement of a marker is impractical; or

(ii) Where a program for preventing interference with underground pipelines is established by law; 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 aboveground.* Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) *Markers other than at navigable waterways.* The following must 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 Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least one inch high with one-quarter inch stroke.

(2) The name of the operator and the 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 must have the following characteristics:

(1) A sign, rectangular in shape, 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—

(i) The word "Warning," "Caution," or "Danger" followed by the words "Do Not Anchor or Dredge" and the words "Gas Pipeline Crossing"; and

(ii) The name of the operator and the 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) (2) (i) of this section is legible, from approaching or passing vessels that may damage or interfere with the pipeline.

(f) *Existing markers.* Line markers installed before April 21, 1975, which do not comply with paragraph (d) or (e) of this section may be used until January 1, 1980.

PSC 192.707

When transmission lines are located outside urban areas, their location shall be marked (recognizable to the public) at each fence line, road crossing, railroad crossing, river, lake, stream, or drainage ditch crossing and wherever it is considered necessary to identify the location of a pipeline to reduce the possibility of damage or interference.

192.709 Transmission lines: record-keeping.

Each operator shall keep records covering each leak discovered, repair made, transmission line break, leakage survey, line patrol, and inspection, for as long as the segment of transmission line involved remains in service.

192.711 Transmission lines: general requirements for repair procedures.

(a) Each operator shall take immediate temporary measures to protect the public whenever—

(1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40% of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery. As soon as feasible, the operator shall make permanent repairs.

(b) Except as provided in 192.717 (c), no operator may use a welded patch as a means of repair.

192.713 Transmission lines: permanent field repair of imperfections and damages.

(a) Except as provided in paragraph (b) of this section each imperfection or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40% of SMYS must be repaired as follows:

(1) If it is feasible, to take the segment out of service, the imperfection or damage must be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment out of service, a full encirclement welded split sleeve of appropriate design must be applied over the imperfection or damage.

(3) If the segment is not taken out of service, the operating pressure must be reduced to a safe level during the repair operations.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the imperfection or damage.

PSC 192.713 (d) Gouges and grooves of lesser depth than 10% of the nominal wall thickness of the pipe may be removed by grinding out to a smooth contour provided the grinding does not reduce the remaining wall thickness to less than the minimum prescribed by this code for the conditions of use.

192.715 Transmission lines: permanent field repair of welds. Each weld that is unacceptable under 192.241 (c) must be repaired as follows:

(a) If is is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of 192.245.

(b) A weld may be repaired in accordance with 192.245 while the segment of transmission line is in service if—

(1) The weld is not leaking;

(2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20% of the SMYS of the pipe; and

(3) Grinding of the defective area can be limited so that at least ⅛-inch thickness in the pipe weld remains.

(c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design.

PSC 192.717 Transmission lines: permanent field repair of leaks.

(a) Except as provided in paragraph (b) of this section, each permanent field repair of a leak on a transmission line must be made as follows:

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

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

(i) Is joined by mechanical couplings; and

(ii) Operates at less than 40 percent of SMYS.

(3) If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp; or, if the leak is due to a corrosion pit and on pipe of not more than 40,000 psi SMYS, the repair may be made by fillet welding over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

(b) Submerged offshore pipelines and submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

192.719 Transmission lines: testing of repairs.

(a) *Testing of replacement pipe.* (1) If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location.

(2) The test required by subparagraph (1) of this paragraph may be made on the pipe before it is installed, but all field girth bolt welds that are not strength tested must be tested after installation by nondestructive tests meeting the requirements of 192.243.

(b) Testing of repairs made by welding. Each repair made by welding in accordance with 192.713, 192.715, and 192.717 must be examined in accordance with 192.241.

PSC 192.720 *Repair of steel pipe operating below 40% of the specified minimum yield strength.*

If inspections at any time reveal an injurious defect, gouge, groove, dent, or leak, immediate temporary measures shall be employed to protect the property and public if it is not feasible to make permanent repair at time of discovery. As soon as feasible, permanent repairs shall be made using recognized methods of repair.

192.721 Distribution systems: patrolling.

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

(b) Mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patroled at intervals not exceeding 3 months.

PSC 192.722 Distribution mains: markers.

When distribution mains are located outside urban areas, their location shall be marked (recognizable to the public) at each fence line, road crossing, railroad crossing, river, lake, stream, or drainage ditch crossing and wherever it is considered necessary to identify the location of a pipeline to reduce the possibility of damage or interference.

192.723 Distribution systems: leakage surveys and procedures.

(a) Each operator of a distribution system shall provide for periodic leakage surveys in its operating and maintenance plan.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A gas detector survey must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 1 year.

(2) Leakage surveys of the distribution system outside of the principal business areas must be made as frequently as necessary, but at intervals not exceeding 5 years.

PSC 192.723

Every operator shall maintain a gas leak-detection program and shall maintain records of operation under the program. The program shall consist of not less than the following:

(a) In principal business districts (as shown by maps filed with the public service commission by each utility) a reasonable street-opening survey shall be conducted twice annually by making tests with combustible gas indicators in street openings such as telephone and electric vaults and manholes, catch basins and sewer system manholes, and gas system openings.

(b) In each principal business district a building survey shall be conducted once a year. The piping from the service entrance to the meter outlet and metering and regulating equipment shall be tested for gas leakage in those buildings that have gas service.

(c) A survey of all buildings used for public gatherings such as schools, churches, hospitals, and theaters shall be conducted once each year. The piping from the service entrance to the meter outlet and metering and regulating equipment shall be tested for gas leakage.

(d) In residential areas, in addition to a survey of public buildings the vegetation shall be checked. At least 3 barhole tests shall be made in each block; at least one street opening shall be checked if one exists in each block or at each intersection; and on streets where system is operating at a pressure of more than 10 p.s.i.g., all street openings shall be checked. (See 192.723 (b) (1) above for types of street openings.) The utility may substitute for the barhole tests a ground surface survey with a hand-operated, continuous-sampling instrument capable of detecting combustible gas in air concentrations of 100 parts per million. The utility may substitute for all the tests required by this section (PSC 192.723 (d)) a survey by mobile flame ionization or infrared gas detection units, provided that a method be included to check individual services. The tests required by this section (PSC 192.723 (d)) shall be made each year.

(e) Along lines in rural areas, the vegetation shall be checked annually.

(f) When a leak complaint is received and the odor of gas indicates that there is a leak in or near the premises, a search shall be carried to conclusion until such leak is found.

PSC 192.724 Further leakage survey after repair of leak.

When a leak is found and repaired, a further check shall be made in the vicinity of the repaired leak to determine if there is any other source of migrant gas in the neighborhood.

192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line must be tested in the same manner as a new service line, before being reinstated.

(b) Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

192.727 Abandonment or inactivation of facilities.

(a) Each operator shall provide in its operating and maintenance plan for abandonment or deactivation of pipelines, including provisions for meeting each of the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of off-shore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

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

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

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

(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

(f) Each abandoned vault must be filled with a suitable compacted material.

PSC 192.727 *(d) Special efforts shall be made to include services which have not been used for two years in a way that will remove gas from the customers' premises. The plan shall include the following provisions:*

(1) If the facilities are abandoned in place, they shall be physically disconnected from the piping system. The open ends of all abandoned facilities shall be capped, plugged, or otherwise effectively sealed.

(2) In cases where a main is abandoned, together with the service lines connected to it, insofar as service lines are concerned, only the customers' end of such service lines need be sealed as stipulated above.

192.729 Compressor stations: procedures for gas compressor units.

Each operator shall establish starting, operating, and shutdown procedures for gas compressor units.

192.731 Compressor stations: inspection and testing of relief devices.

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with 192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested, at intervals not to exceed 1 year, to determine that it functions properly.

192.733 Compressor stations: isolation of equipment for maintenance or alterations.

Each operator shall establish procedures for maintaining compressor stations, including provisions for isolating units or sections of pipe for purging before returning to service.

192.735 Compressor stations: storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30.

PSC 192.735 *(c) All aboveground oil or gasoline storage tanks shall be constructed and protected in accordance with the applicable codes of the department of industry, labor and human relations.*

192.737 Pipe-type and bottle-type holders: plan for inspection and testing.

Each operator having a pipe-type or bottle-type holder shall establish a plan for the systematic, routine inspection and testing of these facilities, including the following:

(a) Provision must be made for detecting external corrosion before the strength of the container has been impaired.

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

(c) The pressure control and pressure limiting equipment must be inspected and tested periodically to determine that it is in a safe operating condition and has adequate capacity.

192.739 Pressure limiting and regulating stations: inspection and testing.

Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected, at intervals not exceeding 1 year, to inspections and tests to determine that it is—

(a) In good mechanical condition;

(b) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(c) Set to function at the correct pressure; and

(d) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

192.741 Pressure limiting and regulating stations: telemetering or recording gages.

(a) Each distribution system supplied by more than one district pressure regulating station must be equipped with telemetering or recording pressure gages to indicate the gas pressure in the district.

(b) On distribution systems supplied by a single district pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gages in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) If there are indications of abnormally high- or low-pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures employed to correct any unsatisfactory operating conditions.

PSC 192.741 *(d) Each low pressure distribution system must be equipped with telemetering or recording pressure gage or gages as may be required to properly indicate the gas pressure in the system at all times. At least once each year the pressure variation shall be determined throughout each system.*

192.743 Pressure limiting and regulating stations: testing of relief devices.

(a) If feasible, pressure relief devices (except rupture discs) must be tested in place, at intervals not exceeding 1 year, to determine that they have enough capacity to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

(b) If a test is not feasible, review and calculation of the required capacity of the relieving device at each station must be made, at intervals not exceeding one year, and these required capacities compared with the rated or experimentally determined relieving capacity of the device for the operating conditions under which it works.

(c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the additional capacity required.

PSC 192.744 Service regulators and associated safety devices: inspection and testing.

Company service regulators and associated safety devices on customers' premises shall be inspected and tested periodically to determine whether they are in proper operating condition. The above shall include testing of the set pressure of the regulator at a specific flow rate, determination of the lock-up pressure, and determine as to whether there are any leaks, internal or external, associated with the regulator. The test interval shall be the same as the interval between meter changes in the meter rotation program. (See section PSC 134.30.)

192.745 Valve maintenance: transmission lines.

Each transmission line valve that might be required during any emergency must be inspected and partially operated, at intervals not exceeding 1 year.

192.747 Valve maintenance: distribution systems.

Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced, at intervals not exceeding 1 year.

PSC 192.747

(a) Inspection shall include checking of alignment to permit use of a key or wrench and clearing from the valve box or vault any

debris which would interfere or delay the operation of the valve. Records shall be maintained to show specific valve location and such records shall be made continuously accessible to authorized personnel for use under emergency conditions.

(b) Existing connections in the form of inline valves between low pressure gas distribution systems and high pressure gas distribution systems shall be physically severed by January 1, 1974.

(c) The by-pass valves in district regulator stations supplying gas to a low pressure distribution system shall be sealed, locked or otherwise be rendered incapable of operation, except by authorized personnel by January 1, 1974.

192.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet or more, must be inspected, at intervals not exceeding 1 year, to determine that it is in good physical condition and adequately ventilated.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any leaks found must be repaired.

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following:

(a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided.

(b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work.

(c) Post warning signs, where appropriate.

PSC 192.751 *(d) Whenever the accidental ignition in the open air of gas-air mixture might be likely to cause personal injury or property damage, precautions shall be taken as, for example:*

(1) Prohibit smoking and open flames in the area, and

(2) Install a metallic bond around the location of cuts in gas pipes to be made by other means than cutting torches, and

(3) Take precautions to prevent static electricity sparks, and

(4) Provide fire extinguishers of appropriate size and type in accordance with the department of industry, labor and human relations' requirements.

PSC 192.753 Caulked bell and spigot joints.

(a) Each cast-iron caulked bell and spigot joint that is subject to pressures of 25 p.s.i.g. or more must be sealed with:

(1) A mechanical leak clamp; or

(2) A material or device which—

(i) Does not reduce the flexibility of the joint;

(ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of 192.53 (a) and (b) and 192.143.

PSC 192.753

Existing unreinforced bell and spigot jointed cast iron pipe shall be operated at low pressure unless it can be proved to the commission that they can be satisfactorily operated at a higher pressure. However, the operating pressure under any circumstances shall not exceed 15 p.s.i.g.

PSC 192.755 Protecting cast-iron pipelines.

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;

(2) Impact forces by vehicles;

(3) Earth-movement;

(4) Apparent future excavations near the pipeline; or

(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with applicable requirements of 192.317 (a), 192.319, and 192.361 (b) - (d).

APPENDIX A—INCORPORATED BY REFERENCE

I. List of organizations and addresses.

A. American National Standards Institute (ANSI), 1430 Broadway, New York, N. Y. 10018 (formerly the United States of American Standards Institute (USASI)). All current standards issued by USASI and ASA have been redesigned as American National Standards and continued in effect.

B. American Petroleum Institute (API), 1801 K Street NW, Washington, D.C. 20006, or 300 Corrigan Tower Building, Dallas, Texas, 75201.

C. The American Society of Mechanical Engineers (ASME) United Engineering Center, 345 East 47th Street, New York, N. Y. 10017.

D. American Society for Testing and Materials (ASTM), 1916 Race Street, Philadelphia, Pa. 19103.

E. Manufacturers Standardization Society of the Valve and Fittings Industry (MSS), 1815 North Fort Myer Drive, Room 913, Arlington, Va. 22209.

F. National Fire Protection Association (NFPA), 470 Atlantic Avenue, Boston, Mass. 02110.

II. Documents incorporated by reference. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to pipe or components which were manufactured, designed, or installed before July 1, 1976, unless otherwise provided in this part.

A. American Petroleum Institute:

(1) API Standard 5A "API Specifications for Casing, Tubing, and Drill Pipe" (1968, 1971, 1973 plus Supp. 1).

(2) API Standard 6A "API Specification for Wellhead Equipment" (1968, 1974).

(3) API Standard 6D "API Specification for Pipeline Valves" (1968, 1974).

(4) API Standard 5L "API Specification for Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

(5) API Standard 5LS "API Specification for Spiral-Weld Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

(6) API Standard 5LX "API Specification for High-Test Line Pipe" (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

(7) API Recommended Practice 5LI "API Recommended Practice for Railroad Transportation of Line Pipe" (1967, 1972).

(8) API Standard 1104 "Standard for Welding Pipe Lines and Related Facilities" (1968, 1973).

B. The American Society for Testing and Materials:

(1) ASTM Specification A53 "Standard Specification for Welded and Seamless Steel Pipe" (A53-65, A53-68, A53-73).

(2) ASTM Specification A72 "Standard Specification for Welded Wrought-Iron Pipe" (A72-64T, A72-68).

(3) ASTM Specification A106 "Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service" (A106-66, A106-68, A106-72a).

(4) ASTM Specification A134 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Plate Pipe, Sizes 16 in. and over" (A134-64, A134-68, A134-73).

(5) ASTM Specification A135 "Standard Specification for Electric-Resistance-Welded Steel Pipe" (A135-63T, A135-68, A135-73a).

(6) ASTM Specification A139 "Standard Specification for Electric-Fusion (Arc)-Welded Steel Pipe (Sizes 4 in. and over)" (A139-64, A139-68, A139-73).

(7) ASTM Specification A155 "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service" (A155-65, A155-68, A155-72a).

(8) ASTM Specification A211 "Standard Specification for Spiral-Welded Steel or Iron Pipe" (A211-63, A211-68, A211-73).

(9) ASTM Specification A333 "Standard Specification for Seamless and Welded Steel Pipe for Low Temperature Service" (A333-64, A333-67, A333-73).

(10) ASTM Specification A372 "Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessel" (A372-67, A372-71).

(11) ASTM Specification A377 "Standard Specifications for Cast Iron and Ductile Iron Pressure Pipe" (A377-66, A377-73).

(12) ASTM Specification A381 "Standard Specification for Metal-Arc-Welded Steel Pipe for High-Pressure Transmission Systems" (A381-66, A381-68, A381-73).

(13) ASTM Specification A539 "Standard Specification for Electric Resistance-Welded Coiled Steel Tubing for Gas and Fuel Oil Lines" (A539-65, A539-73).

(14) ASTM Specification B42 "Standard Specification for Seamless Copper Pipe, Standard Sizes" (B42-62, B42-66, B42-72).

(15) ASTM Specification B68 "Standard Specification for Seamless Copper Tube, Bright Annealed" (B68-65, B68-68, B68-74).

(16) ASTM Specification B75 "Standard Specification for Seamless Copper Tube" (B75-65, B75-68, B75-74).

(17) ASTM Specification B88 "Standard Specification for Seamless Copper Water Tube" (B88-66, B88-72).

(18) ASTM Specification B251 "Standard Specification for General Requirements for Wrought Seamless Copper and Copper-Alloy Tube" (B251-66, B251-68, B251-72).

(19) ASTM Specification D2513 "Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings" (D2513-66T, D2513-68, D2513-70, D2513-71, D2513-73, D2513-74a).

(20) ASTM Specification D2517 "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (D2517-66T, D2517-67, D2517-73).

C. The American National Standards Institute, Inc.:

(1) ANSI A21.1 "Thickness Design of Cast-Iron Pipe" (A21.1-1967, A21.1-1972).

(2) ANSI A21.3 "Specifications for Cast Iron Pit Cast Pipe for Gas" (A21.3-1953).

(3) ANSI A21.7 "Cast-Iron Pipe Centrifugally Cast in Metal Molds for Gas" (A21.7-1962).

(4) ANSI A21.9 "Cast-Iron Pipe Centrifugally Cast in Sand-Lined Molds for Gas" (A21.9-1962).

(5) ANSI A21.11 "Rubber-Gasket Joints for Cast-Iron and Ductile-Iron Pressure Pipe and Fittings" (A21.11-1964, A21.11-1972).

(6) ANSI A21.50 "Thickness Design of Ductile-Iron Pipe" (A21.50-1965, A21.50-1971).

(7) ANSI A21.52 "Ductile-Iron Pipe, Centrifugally Cast, in Metal Molds or Sand-Lined Molds for Gas" (A21.52-1965, A21.52-1971).

(8) ANSI B16.1 "Cast Iron Pipe Flanges and Flanged Fittings" (B16.1-1967).

(9) ANSI B16.5 "Steel Pipe Flanges, Flanged Valves and Fittings (B16.5-1968, B16.5-1973).

(10) ANSI B16.24 "Bronze Flanges and Flanged Fittings" (B16.24-1962, B16.10-1971).

(11) ANSI B36.10 "Wrought Steel and Wrought Iron Pipe" (B36.10-1959, B36.10-1970).

(12) ANSI C1 "National Electrical Code" (C1-1968, C1-1975).

D. The American Society of Mechanical Engineers:

(1) ASME Boiler and Pressure Vessel Code Section VIII "Pressure Vessels, Division 1" (1968, 1974).

(2) ASME Boiler and Pressure Vessel Code, Section IX "Welding Qualifications" (1968, 1974).

E. Manufacturer's Standardization Society of the Valve and Fittings Industry:

(1) MSP-25 "Standard Marking System for Valves, Fittings, Flanges, and Union" (1964).

(2) MSS SP-44 "Steel Pipe Line Flanges" (1955, 1972, 1975).

(3) MSS SP-52 "Cast Iron Pipe Line Valves" (1957).

(4) MSS SP-70 "Cast Iron Gate Valves, Flanged and Threaded Ends" (1970).

(5) MSS Sp-71 "Cast Iron Swing Check Valves, Flanged and Threaded Ends" (1970).

(6) MSS Sp-78 "Cast Iron Plug Valves" (1972).

F. National Fire Protection Association:

(1) NFPA Standard 30 "Flammable and Combustible Liquids Code" (1969, 1973).

(2) NFPA Standard 58 "Standard for the Storage and Handling of Liquefied Petroleum Gases" (1969, 1972).

(3) NFPA Standard 59 "Standard for the Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants" (1968).

(4) NFPA Standard 59A "Storage and Handling Liquefied Natural Gas" (1971, 1972).

Appendix B—Qualification of Pipe

I. Listed Pipe Specifications. Numbers in parentheses indicate applicable editions. Only the latest listed edition applies, except that an earlier listed edition may be followed with respect to pipe or components which were manufactured, designed, or installed before July 1, 1976, unless otherwise provided in this Part.

API 5L—Steel and iron pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

API 5LS—Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

API 5LX—Steel pipe (1967, 1970, 1971 plus Supp. 1, 1973 plus Supp. 1, 1975).

ASTM A53—Steel pipe (1965, 1968, 1973).

ASTM A72—Wrought Iron Pipe (1964T, 1968).

ASTM A106—Steel pipe (1966, 1968, 1972a).

ASTM A134—Steel pipe (1964, 1968, 1973).

ASTM A135—Steel pipe (1963T, 1968, 1973a).

ASTM A139—Steel pipe (1964, 1968, 1973).

ASTM A155—Steel pipe (1965, 1968, 1972a).

ASTM A211—Steel and iron pipe (1963, 1968, 1973).

ASTM A333—Steel pipe (1964, 1967, 1973).

ASTM A377—Cast iron pipe (1966, 1973).

ASTM A381—Steel pipe (1966, 1968, 1973).

ASTM A539—Steel tubing (1965, 1973).

ASTM B42—Copper pipe (1962, 1966, 1972).

ASTM B68—Copper tubing (1965, 1968, 1974).

ASTM B75—Copper tubing (1965, 1968, 1974).

ASTM B88—Copper tubing (1966, 1972).

ASTM B251—Copper pipe and tubing (1966, 1968, 1972).

ASTM D2513—Thermoplastic pipe and tubing (1966T, 1968, 1970, 1971, 1973, 1974a).

ASTM D2517—Thermosetting plastic pipe and tubing (1966T, 1967, 1973).

ANSI A21.3—Cast iron pipe (1953).

ANSI A21.7—Cast iron pipe (1962).

ANSI A21.9—Cast iron pipe (1962).

ANSI A21.52—Ductile iron pipe (1965, 1971).

II. *Steel pipe of unknown or unlisted specification.*

A. *Bending Properties.* For pipe 2 inches or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches in diameter, the pipe must meet the requirements of the flattening test set forth in ASTM A53, except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. *Weldability.* A girth weld must be made in the pipe by a welder who is qualified under Subpart E of this part. The weld must be made under the most severe conditions which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104. If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code. The same number of chemical tests must be made as are required for testing a girth weld.

C. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. *Tensile Properties.* If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i.g. or less, or the tensile properties may be established by performing tensile tests as set forth in API Standard 5LX. All test specimens shall be selected at random and the following number of tests must be performed:

Number of Tensile Tests—All Sizes

10 lengths or less—1 set of tests for each length.

11 to 100 lengths—1 set of tests for each 5 lengths, but not less than 10 tests.

Over 100 lengths—1 set of tests for each 10 lengths, but not less than 20 tests.

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in 192.55 (c).

III. *Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.* Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this appendix, is qualified for use under this part if the following requirements are met:

A. *Inspection.* The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. *Similarity of specification requirements.* The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this appendix:

(1) Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.

(2) Chemical properties of pipe and testing requirements to verify those properties.

C. *Inspection or test of welded pipe.* On pipe with welded seams, one of the following requirements must be met:

(1) The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this appendix.

(2) The pipe must be tested in accordance with Subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under Subpart J of this part, the test pressure must be maintained for at least 8 hours.

APPENDIX C—QUALIFICATION FOR WELDERS OF LOW STRESS LEVEL PIPE

I. *Basic test.* The test is made on pipe 12 inches or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than ⅛-inch long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered.

II. *Additional tests for welders of service line connections to mains.* A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fittings and run pipe.

III. *Periodic tests for welders of small service lines.* Two samples of the welder's work each about 8 inches long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

APPENDIX D—CRITERIA FOR CATHODIC PROTECTION AND DETERMINATION OF MEASUREMENTS

I. *Criteria for cathodic protection—A. Steel, cast iron, and ductile iron structures.*

(1) A negative (cathodic) voltage of at least 0.85 volt, with reference to a saturated copper-copper sulfate half cell. Determination of this voltage must be made with the protective current applied, and in accordance with sections II and IV of this appendix.

(2) A negative (cathodic) voltage shift of at least 300 millivolts. Determination of this voltage shift must be made with the protective current applied, and in accordance with sections II and IV of this appendix. This criterion of voltage shift applies to structures not in contact with metals of different anodic potentials.

(3) A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(4) A voltage at least as negative (cathodic) as that originally established at the beginning of the Tafel segment of the E-log-I curve. This voltage must be measured in accordance with section IV of this appendix.

(5) A net protective current from the electrolyte into the structure surface as measured by an earth current technique applied at predetermined current discharge (anodic) points of the structure.

B. *Aluminum structures.* (1) Except as provided in subparagraph (3) and (4) of this paragraph, a minimum negative (cathodic) voltage shift of 150 millivolts, produced by the application of protective current. The voltage shift must be determined in accordance with sections II and IV of this appendix.

(2) Except as provided in subparagraphs (3) and (4) of this paragraph, a minimum negative (cathodic) polarization voltage shift

of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

(3) Notwithstanding the alternative minimum criteria in subparagraphs (1) and (2) of this paragraph, aluminum, if cathodically protected at voltages in excess of 1.20 volts as measured with reference to a copper-copper sulfate half cell, in accordance with section IV of this appendix, and compensated for the voltage (IR) drops other than those across the structure-electrolyte boundary, may suffer corrosion resulting from the buildup of alkali on the metal surface. A voltage in excess of 1.20 volts may not be used unless previous test results indicate no appreciable corrosion will occur in the particular environment.

(4) Since aluminum may suffer from corrosion under high pH conditions, and since application of the cathodic protection tends to increase the pH at the metal surface, careful investigation or testing must be made before applying cathodic protection to stop pitting attack on aluminum structures in environments with a natural pH in excess of 8.

C. *Copper structures.* A minimum negative (cathodic) polarization voltage shift of 100 millivolts. This polarization voltage shift must be determined in accordance with sections III and IV of this appendix.

D. *Metals of different anodic potentials.* A negative (cathodic) voltage, measured in accordance with section IV of this appendix, equal to that required for the most anodic metal in the system must be maintained. If amphoteric structures are involved that could be damaged by high alkalinity covered by subparagraphs (3) and (4) of paragraph B of this section, they must be electrically isolated with insulating flanges, or the equivalent.

II. *Interpretation of voltage measurement.* Voltage (IR) drops other than those across the structure-electrolyte boundary must be considered for valid interpretation of the voltage measurement in paragraph A (1) and (2) and paragraph B (1) of section I of this appendix.

III. *Determination of polarization voltage shift.* The polarization voltage shift must be determined by interrupting the protective current and measuring the polarization decay. When the current is initially interrupted, an immediate voltage shift occurs. The voltage reading after the immediate shift must be used as the base reading from which to measure polarization decay in paragraphs A (3), B (2), and C of section I of this appendix.

IV. *Reference half cells.* A. Except as provided in paragraphs B and C of this section, negative (cathodic) voltage must be measured between the structure surface and a saturated copper-copper sulfate half cell contacting the electrolyte.

B. Other standard reference half cells may be substituted for the saturated copper-copper sulfate half cell. Two commonly used reference half cells are listed below along with their voltage equivalent to —0.85 volt as referred to a saturated copper-copper sulfate half cell:

(1) Saturated KC1 calomel half cell: —0.78 volt.

(2) Silver-silver chloride half cell used in sea water:—0.80 volt.

C. In addition to the standard reference half cells, an alternate metallic material or structure may be used in place of the saturated copper-copper sulfate half cell if its potential stability is assured and if its voltage equivalent referred to a saturated copper-copper sulfate half cell is established.

History: Cr. Register, May, 1972, No. 197, eff. 6-1-72; cr. 192.12, 192.379, appendix A-II F 4; am. 192.201 (a), 192.625 (g) (1), 192.717 (b), 192.727, Register, February, 1973, No. 206, eff. 3-1-73; am. PSC 192.457 (d), PSC 192.613 (c) (1), Register, June, 1974, No. 222, eff. 7-1-74; am. 192.3, 192.55 (a) (2) and (b) (2), 192.65, 192.197 (a), 192.625 (g) (1), appendix A-I, B, and II A, 1., 2., 3., and 5., appendix B, I, cr. appendix B, III, Register, December, 1974, No. 228, eff. 1-1-75; am. 192.59 (a) (1), (b) (1) and cr. (c), am. 192.65 (a), 192.225 (a), 192.227 (a) (2), 192.229 (c), 192.241 (c), 192.625 (a) and (b), 192.625 (g) (1), 192.705 (a) and (b), r. 192.705 (c), cr. 192.706, am. 192.707, appendix A II and appendix B I, Register, March, 1976, No. 243, eff. 4-1-76.