SUBCHAPTER C, Safety

PART 255
TRANSMISSION AND DISTRIBUTION OF GAS

§255.179 Valves on pipelines to operate at 125 PSIG (862 kPa) or more.

§255.243 Nondestructive testing-Pipeline to operate at 125 PSIG (862 kPa) or more.

§255.383 Excess flow valve customer [notification]installation.

§255.475 Internal corrosion control: General.
§255.476 Internal corrosion control: Design and construction of transmission line.
§255.477 Internal corrosion control: Monitoring.

§255.505 Strength test requirements for steel pipelines to operate at 125 PSIG (862 kPa) or more.
§255.507 Test requirements for pipelines to operate at less than 125 PSIG (862 kPa).

§255.555 Upgrading to a pressure of 125 PSIG (862 kPa) or more in steel pipelines.
§255.557 Upgrading to a pressure less than 125 PSIG (862 kPa).

§255.629 Purging of pipelines.
§255.631 Control room management.

§255.831 Reporting safety-related conditions.
Transmission Pipeline Integrity Management
§255.901 Scope.

§255.1 Scope.
(d) This Part does not apply to:
(2) piping with metal temperatures above 450 degrees Fahrenheit (232°C) or below minus 20 degrees Fahrenheit (-29°C);
(6) wellhead assemblies, including traps or separators, heaters, control valves, and flow lines of less than 100 foot (30.5 meters)in length between the wellhead and trap or separator, or casing and tubing in gas or oil wells (flowlines of greater than 100 feet (30.5 meters) in

length between the wellhead and trap or separator are considered to be gathering lines);

§255.3 Definitions.

(a) As used in this Part:

(1) Approved means prior approval must be granted by the, [Gas and Water Division of the Department of Public Service]Department, except in emergency situations.

(44) Department. For this Part, Department shall mean the Department of Public Service, Office of Electric, Gas and Water, Safety Section, or its successor, 3 Empire State Plaza, Albany, New York 12223-1350, 518-474-5453, Safety@dps.state.ny.us.

(45) Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

(46) Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

(47) Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

(48) Supervisory Control and Data Acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

§255.4 Notifications and reports.

Unless otherwise indicated in this Part, submission of any notification, program, plan, letter of intent, procedure, or written or telephonic report as required by any provision of this Part shall be to the [Albany office of the Gas and Water Division of the Department of Public Service, 3 Empire State Plaza, Albany, NY 12223-1350, 518-474-5453]Department.

§255.5 Class locations.

(a) Except as provided in paragraphs (d)(2) and (e)(2) of this section, the class location is determined by the number of buildings intended for human occupancy in the class location unit. The class location unit is an area that extends 220 yards (201.17 meters) on either side of the centerline of any continuous 1-mile (1.61 kilometers) length of pipeline. For the purposes of this section, each separate dwelling unit in a multiple dwelling building is counted as a separate building intended for human occupancy.

(d) A Class 3 location is:
   (2) an area where the pipeline lies within 100 yards (91.44 meters) of either a building or 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).

(f) The boundaries of the class location unit determined in accordance with paragraphs (a) through (e) of this section may be extended according to the following.
   (1) When a cluster of buildings intended for human occupancy otherwise requires a Class 2, 3, or 4 location, the class location unit ends 220 yards (201.17 meters) from the nearest building in the cluster.
   (2) When the number of buildings with four or more stories requires a Class 4 location, the class location unit ends 220 yards (201.17 meters) from the nearest building with four or more stories.

§255.7 Incorporation by reference.

(b) All incorporated documents are available for inspection [in the Albany office of the Gas and Water Division, 3 Empire State Plaza, Department of Public Service, Building 3, Empire State Plaza, Albany, New York]at the Department. In addition, the documents are available at the addresses provided in Section 10.3 of Title 16 of the official Compilation of Codes, Rules and Regulations of the State of New York (16 NYCRR).

§255.9 Gathering lines.

(b) Gathering lines or any portion thereof located within the following areas shall be designed, constructed, tested, operated and maintained in accordance with the provisions of this Part applicable to steel transmission lines:
   (1) within 150 feet (45.72 meters) of an existing residence or place of public assembly;

(c) Prior to the start of construction of any gathering line, notification in compliance with the following paragraphs shall be filed.
   (1) At least 30 days prior to the start of construction for any gathering line intended to operate at a pressure of 125 PSIG (862 kPa) or more, the notice must be a letter

of intent and a report of specifications similar in format to Appendix 7-G of this Part.

(2) At least 48 hours prior to the start of construction for any gathering line intended to operate at a pressure of less than 125 PSIG (862 kPa), the notice is to be a letter of intent giving the company name, address, and specific location of the intended construction.

(e) Any person operating a gathering line (regardless of the pipeline material) which was originally constructed to operate at a pressure of less than 125 PSIG (862 kPa) who proposes to increase the operating pressure of such line to 125 PSIG (862 kPa) or more shall comply with the requirements of sections 255.552, 255.553, and 255.555.

(f) Any gathering line, except as specified in subdivision 255.9(b), shall be designed, constructed, tested, operated and maintained in conformance with sound engineering practices, including the following criteria.

(2) Except as provided in paragraph 255.9(f)(3), all pipe shall be installed with a minimum of 24 inches (610 millimeters) of cover. Where solid rock is encountered, the minimum cover may be reduced to 12 inches (305 millimeters). In areas subject to erosion or in locations where future grading is likely, such as at road, highway, railroad and ditch crossings, additional protection shall be provided.

(3) Notwithstanding paragraph 255.9(f)(2), in areas actively cultivated for commercial farm purposes in at least two out of the last five years, as identified by the farmland operator, all pipe shall be installed with a minimum 40 inches (1016 millimeters) of cover. The farmland operator can also designate such support land areas, not under active cultivation but subject to land management practices such as, but not limited to, drainage and soil erosion control systems. The farmland operator may allow less than 40 inches (1016 millimeters) of cover if less conforms with normal agricultural practices, including land fitting (e.g., plowing, subsoiling, disking, etc.) and prospective agricultural engineering projects taking into account and the recommended practices and standards of the United States Department of Agriculture, Soil Conservation Service contained in its National Handbook of Conservation Practices and its National Engineering Manual. The farmland operator may require a depth-of-cover greater than 40 inches (1016 millimeters) as a condition of permitting a right-of-way across his or her land where necessary to safely accommodate such practices and projects. Information about soil types and applicable

agricultural engineering standards and practices may be obtained from the U.S. Department of Agriculture, Soil Conservation Service office, located in the county in which the gathering line is to be installed.

(8) The pipeline shall be subjected to a minimum pressure test of 100 PSIG (689 kPa) or 1 1/2 MAOP, whichever is greater, for two hours. However, the maximum test pressure for plastic pipe may not be more than three times the design pressure of the pipe. Where reservoir pressure of the field is less than these pressures, the reservoir pressure may be the test pressure.

§255.13 General.

(b) In complying with this Part, operators shall use methods that are reasonable and proper for the anticipated operating conditions and that can reasonably be expected to provide a level of safety equivalent to or greater than that which would result from following the generally accepted standards of the gas industry. The [guidelines of the American Society of Mechanical Engineers Guide for Gas Transmission and Distribution Piping System]Gas Piping Technology Committee Guide (GPTC) for Gas Transmission and Distribution Piping Systems is[are], except where in conflict with provisions of this Part, representative of this level of practice.

§255.17 Preservation of records.

(b) All records pertaining to any pipeline designed to operate at 125 PSIG (862 kPa) or more shall be kept in files reserved for that pipeline only and retained for as long as the line remains in service.

§255.55 Steel pipe.

(c) New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 psi (41 MPa) where no close coiling or close bending is to be done,

§255.105 Design formula for steel pipe.

P = Design pressure in pounds per square inch (kPa) gauge.

S = Yield strength in pounds per square inch (kPa) determined in accordance with section 255.107.

D = Nominal outside diameter of the pipe in inches (millimeters).

t = Nominal wall thickness of the pipe in inches (millimeters).

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

§255.107 Yield strength (S) for steel pipe.

(2) if the pipe is not tensile tested as provided in paragraph (b) (1) of this section, 24,000 psi (165 MPa).

§255.109 Nominal wall thickness (t) for steel pipe.

(b) However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

§255.113 Longitudinal joint factor (E) for steel pipe.

(a) The longitudinal joint factor to be used in the design formula in section 255.105 is determined in accordance with the following table:

Other	Pipe over 4 inches (102 millimeters)	80
	Pipe 4 inches (102 millimeters) or less	..60

§255.115 Temperature derating factor (T) for steel pipe.

(a) The temperature derating factor to be used in the design formula in section 255.105 is determined as follows:

Gas Temp. in degrees Fahrenheit (Celsius)	Temperature derating factor (T)
250 (121) or less	l.000
300 (149)	0.967
350 (177)	0.933
400 (204)	0.900
450 (232)	0.867

§255.121 Design of plastic pipe.

The design pressure for plastic pipe is determined [in accordance with]by either of the following formulas, subject to the limitations of section 255.123:

$$P = \frac{2St \times DF[0.32]}{(D-t)} \qquad P = \frac{2S \times DF[0.32]}{(SDR-1)}$$

P = Design pressure, PSIG (kPa).

S = For thermoplastic pipe the Hydrostatic Design Basis (HDB) determined in accordance with the listed specification at a temperature equal to 73°F (23°C), 100°F (38°C), 120°F (49°C), or 140°F (60°C). In the absence an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part E of PPI TR–3[/2000] entitled, Policy for Determining Long-Term Strength (LTHS) by Temperature Interpolation, as published in the technical Report TR–3[/2000] ''HDB/PDB/MRS Policies'' (as described in section 10.3 of this Title). For reinforced thermosetting plastic pipe, 11,000 psi (75.8 MPa). [Note: Arithmetic interpolation is not allowed for PA-11 pipe.]

t = Specified wall thickness, [in]inches (millimeters).

D = Specified outside diameter, [in]inches (millimeters).

SDR = Standard Dimension Ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.

DF = 0.32 or

0.40 for PA-11 pipe produced after January 23, 2009 with nominal size (IPS or CTS) 4-inch or less, and a SDR of 11 or greater (i.e. thicker pipe wall)

§255.123 Design limitations for plastic pipe.

(a) Except as provided for in paragraph (e) and paragraph (f) of this section and in paragraph 255.9(f)(6) for gathering lines, the design pressure may not exceed a gauge pressure of 100 PSIG (689kPa).

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

(1) below -20 degrees F (-29°C), or -40 degrees F (-40°C) if all pipe and pipeline components whose operating temperature will be below -20 degrees F (-29°C) have a temperature rating by the manufacturer consistent with that operating temperature; or

(2) in the case of thermoplastic pipe, above the temperature at which the long-term hydrostatic strength used in the

design formula under section 255.121 is determined, except that thermoplastic pipe manufactured before May 18, 1978, may be used at temperatures up to 100 degrees F (38°C); or

(3) in the case of reinforced thermosetting plastic pipe up to 150 degrees F (66°C).

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

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

Nominal Diameter [(in inches)] inches (millimeters)	Minimum wall thickness [(in inches)] inches (millimeters)
2 (51)	0.060 (1.52)
3 (76)	0.060 (1.52)
4 (102)	0.070 (1.78)
6 (152)	0.100 (2.54)

(f) The design pressure for polyamide-11 (PA-11) pipe produced after January 23, 2009 may exceed a gauge pressure of 100 PSIG (689 kPa) provided that:

(1) The design pressure does not exceed 200 PSIG (1379 kPa);

(2) The pipe size is nominal pipe size (IPS or CTS) 4-inch or less; and

(3) The pipe has a standard dimension ratio of SDR-11 or greater (i.e., thicker pipe wall).

§255.125 Design of copper pipe.

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.

(c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 PSIG (689 kPa).

(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 (2.83 cubic meters) of gas.

§255.143 General requirements.

(a) Each component of a pipeline must be able to withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

(b) The design and installation of pipeline components and facilities must meet applicable requirements for corrosion control found in this Part.

§255.145 Valves.

(1) the temperature-adjusted service pressure does not exceed 1,000 PSIG (6.9 MPa); and

§255.151 Tapping.

(c) Where the diameter of a threaded tap in cast iron or ductile iron pipe exceeds 25 percent of the nominal diameter of the pipe, the pipe must be reinforced, except that a 1¼-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement. In cast iron pipe of a nominal diameter of six inches (152 millimeters) or less, all threaded taps for service line connections must be reinforced.

§255.153 Components fabricated by welding.

(c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a pressure of 125 PSIG (862 kPa) or more.

(d) Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code (as described in Section 10.3 of this Title), flat closures and fish tails may not be used on pipe that either operates at 100 PSIG (689 kPa) or more, or is more than 3 inches (76 millimeters) nominal diameter.

§255.163 Compressor stations: Design and construction.

(b) Each building on a compressor station site must be made of noncombustible materials if it contains either:
   (1) pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure; or

(d) Each fence around a compressor station must have at least two gates located so as to provide a convenient opportunity for escape to a place of safety, or have other facilities affording a similarly convenient exit from the area. Each gate located within 200 feet (61 meters) of any compressor plant building must open outward and, when occupied, must be openable from the inside without a key.

§255.167 Compressor stations: Emergency shutdown.
Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following.
(d) It must be operable from at least two locations, each of which is:
   (3) not more than 500 feet (152.4 meters) from the limits of the station.

§255.179 Valves on pipelines to operate at 125 PSIG (862 kPa) or more.
(a) Each pipeline to operate at 125 PSIG (862 kPa) or more must have sectionalizing block valves spaced according to the following.
   (1) Each point on the pipeline in a Class 4 location must be within 1/2 mile (0.805 kilometer) of a valve.
   (2) Each point on the pipeline in a Class 3 location must be within 2 miles (3.22 kilometers) of a valve.
   (3) Each point on the pipeline in a Class 2 location must be within 3 1/2 miles (5.63 kilometers) of a valve.
   (4) Each point on the pipeline in a Class 1 location must be within 5 miles (8.05 kilometers) of a valve
(b) Each sectionalizing block valve and operating device on a pipeline to operate at 125 PSIG (862 kPa) or more must:
   (1) be readily accessible and protected from tampering and damage; and
(c) Each section of a pipeline to operate at 125 PSIG (862 kPa) or more must have a blow-down valve with enough capacity to allow the line to be blown down as rapidly as practicable or other approved means to reduce the pressure.

§255.181 Distribution line valves.
(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.
   (1) Such distance must be at least 50 feet (15.2 meters) but no more than 1,000 feet (304.8 meters) from the regulator.

(2) Under unique circumstances which make it impractical to locate the valve at least 50 feet (15.2 meters) from the regulator, a lesser, approved spacing may be used.

§255.183 Vaults Structural design requirements.

(c) Each pipe entering, or within, a regulator vault or pit must be steel for sizes 10 inches (254 millimeters) and less, except that control and gauge piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gasses or liquids through the opening and to avert strains in the pipe.

§255.187 Vaults: Sealing, venting, and ventilation.

(b) When the internal volume exceeds 200 cubic feet (5.66 cubic meters), each of the following apply.

(1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter.

(c) When the internal volume is more than 75 cubic feet (2.12 cubic meters) but less than 200 cubic feet (5.66 cubic meters), the following apply.

§255.197 Control of the pressure of gas delivered from high pressure distribution systems.

(4) The pipe connections to the regulator do not exceed 2 inches (51 millimeters) in diameter.

(5) Any service line operating at 125 PSIG (862 kPa) or more serving customers requiring regulation of the line pressure is to be equipped with either an excess flow valve or must have the first stage regulator located at least 50 feet (15.2 meters) from the building or, if 50 feet (15.2 meters) cannot be attained without entering the roadway, located at the property line.

§255.199 Requirements for design of pressure relief and limiting devices.

(b) For new installations, and for existing above ground stations supplying low pressure pipelines, the minimum separation distance between the overpressure protection device and the regulator or between stages of regulation shall be:

(1) 50 feet (15.2 meters); or

(2) where it is impracticable because of interfering subsurface structures, not less than 25 feet (7.6 meters)

upon approval of the [Gas and Water Division, New York State Department of Public Service]Department.

§255.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief or pressure limiting station or group of stations installed in a low pressure distribution system must have enough capacity, and must be set to operate, to [insure]ensure that the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(b) Each pressure relief or pressure limiting station or group of stations installed in pipelines other than low pressure distribution systems must have enough capacity, and must be set to operate to limit the pressure according to the following paragraphs.

(1) If the maximum allowable operating pressure is 60 PSIG (414 kPa) or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower.

(2) If the maximum allowable operating pressure is 12 PSIG (83 kPa) or more, but less than 60 PSIG (414 kPa), the pressure may not exceed the maximum allowable operating pressure plus 6 PSIG (41.4 kPa).

(3) If the maximum allowable operating pressure is less than 12 PSIG (83 kPa), the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

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

(d) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low pressure distribution system, with a capacity to limit the maximum pressure in the main to 2 PSIG (14 kPa).

§255.203 Instrument, control, and sampling piping and components.

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

(3) Brass or copper material may not be used for metal temperatures greater than 400 degrees F (204°C).

§255.227 Qualification of welders.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure of less than 125 PSIG (862 kPa) by performing an acceptable test weld, for the welding process to be used, under the test set forth in section I of Appendix 14-F 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 14-F to this Part as a part of the qualifying test.

§255.229 Limitations on welders.

(iii) for welders who work only on service lines 2 inches (51 millimeters) or smaller in diameter, two sample welds tested and found acceptable in accordance with the test in section III of Appendix 14-F to this Part.

§255.239 Stress relieving.

(c) Except as provided in subdivision (f) of this section, each weld on carbon steel pipe with a wall thickness of more than 1-1/4 inches (32 millimeters) must be stress relieved.

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

(1) a fillet or groove weld one-half inch (13 millimeters), or less, in size (leg) that attaches a connection 2 inches (51 millimeters), or less, in diameter; or

(2) a fillet or groove weld three-eighths inch (9.5 millimeters), 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 1100 degrees F (593 °C) for carbon steels and at least 1200 degrees F (649 °C) for ferritic alloy steels.

§255.241 Inspection and test of welds.

(b) The butt welds on each pipeline with a nominal diameter greater than 2 inches (51 millimeters) to be operated at 125

PSIG (862 kPa) or more must be nondestructively tested in accordance with section 255.243.

§255.243 Nondestructive testing-Pipeline to operate at 125 PSIG (862 kPa) or more.

§255.244 Welding inspector.

(c) When inspecting pipelines to be operated at 125 PSIG (862 kPa) or more, a welder may not inspect his own welds for the purpose of determining the acceptability of the welds as required by section 255.241.

§255.245 Repair or removal of defects.

(a) Each weld that is unacceptable under subdivision 255.241(c) must be removed or repaired. A weld must be removed if it has a crack that:
   (1) is more than 8 percent of the weld length or 2 inches (51 millimeters) in length whichever is less; or

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability. Repairs on pipelines to operate at 125 PSIG (862 kPa) or more must be nondestructively inspected and meet the standards in section 6 of API 1104 (as described in Section 10.3 of this Title).

§255.273 General.

(c) Each joint must be inspected to [insure]ensure compliance with this Part.

§255.283 Plastic pipe: Qualifying joining procedures.

(3) The speed of testing is 0.20 in. (5.1 millimeters) per minute, plus or minus 25 percent.

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

(5) Pipe specimens 4 in. (102 millimeters) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 degrees

F (38°C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower, must be used in the design calculations for stress.

§255.302 Notification requirements.

(a) At least 30 days prior to the start of construction or reconstruction of any transmission line or main designed to operate at 125 PSIG (862 kPa) or more, each operator shall file a letter of intent and a report of specifications identical with Form A of Appendix 7-D. The letter of intent need not include said specifications where the length of the line is less than the following:

Class Location	Length
Class 1	1,000 feet (304.8 meters)
Class 2	500 feet (152.4 meters)
Class 3	250 feet (76.2 meters)
Class 4	100 feet (30.5 meters)

(b) Before any pipeline designed to operate at 125 PSIG (862 kPa) or more is placed in operation, a report shall be filed certifying the maximum allowable operating pressure to which the line is intended to be subjected and also certifying that the line has been constructed and tested in accordance with the requirements of the rules herein prescribed.

§255.303 Compliance with construction standards.

All construction work performed on piping systems in accordance with the requirements of this Part shall be done under construction standards which shall be readily available for inspection by the [Gas and Water Division, New York State Department of Public Service.]Department. The construction standards shall cover all phases of the work and shall be in sufficient detail to cover the requirements of this Part.

§255.309 Repair of steel pipe.

(c) Each of the following dents must be removed from steel pipe to be operated at a pressure of 125 PSIG (862 kPa) or more, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe

(3) a dent that has a depth of more than one-quarter inch (6.4 millimeters) in pipe 12 3/4 inches (324 millimeters) or less in outer diameter; or

(4) a dent that has a depth of more than 2 percent of the nominal pipe diameter in pipe over 12 3/4 inches (324 millimeters) in outer diameter.

(e) Each arc burn on steel pipe to be operated at a pressure of 125 PSIG (862 kPa) or more must be repaired or removed.

(i) Notches or laminations on pipe ends shall not be repaired on pipe to be operated at a pressure of 125 PSIG (862 kPa) or more. The damaged portion shall be removed as a cylinder and the pipe end rebeveled.

§255.313 Bends and elbows.

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

(2) the pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.

(c) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested after the bending process.

(d) 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 (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).

§255.315 Wrinkle bends in steel pipe.

A wrinkle bend may not be made on steel pipe to be operated at a pressure of 125 PSIG (862 kPa) or more.

§255.321 Installation of plastic pipe.

(d) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inches (2.29 millimeters), except that pipe with an outside diameter of 0.875 inches (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inches (1.58 millimeters).

§255.325 Underground clearance.

(a) Each transmission line shall be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, a minimum clearance of 2 inches (51 millimeters) must be attained provided the transmission line is protected from damage that might result from the proximity of the other structure.

(b) Each distribution main shall be installed with at least 6 inches (152 millimeters) of clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures. If this clearance cannot be attained, the main may be installed with a minimum clearance of 2 inches (51 millimeters), provided the main is suitably protected from damage that might result from the proximity of the other structure.

§255.353 Customer meters and regulators: Location.

(d) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.

§255.355 Customer meters and regulators: Protection from damage.

(2) be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building (a minimum of 18 inches (457 millimeters), where practical); and

§255.359 Customer meter installations: Operating pressure.

(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 PSIG (69 kPa).

§255.361 Service lines: Installation.

(a) Each buried service line shall be installed with at least 18 inches (457 millimeters) of cover. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load and suitable protection must be provided. Also, if service inserts of existing service lines are installed this requirement is not applicable.

(g) All service lines shall be constructed with a clearance of not less than 4 inches (102 millimeters), whenever practical, from any subsurface structures not directly associated with the pipeline. If it is not practicable to achieve this clearance, a minimum clearance of 2 inches (51 millimeters) shall be maintained and the pipeline shall be protected from damage that might result from the proximity of the other structure.

§255.363 Service lines: valve requirements.

(d) On service lines designed to operate at pressures in excess of 60 PSIG (414 kPa), the service line valve shall be the equivalent of a pressure lubricated valve or a needle type valve. Other types of valves may be used where tests by the manufacturer or by the user indicate that they are suitable for this kind of service.

§255.365 Service lines: Location of valves.

(b) Each service line must have a shut off valve in a readily accessible location that, if feasible, is outside of the building. The valve must be located outside the building:
   (3) on service lines 2 inches (51 millimeters) or greater in diameter.

§255.371 Service lines: Steel.

Each steel service line to be operated at less than 100 PSIG (689 kPa) must be constructed of pipe designed for a minimum of 100 PSIG (689 kPa).

§255.381 Service lines: excess flow valve performance standards.

(a) Excess flow valves to be used on single residence service lines that operate continuously throughout the year at a pressure not less than 10 [psig]PSIG (69 kPa) must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to [insure]ensure that each valve will:
   (3) at 10 [psig]PSIG (69 kPa) close at, or not more than 50% above, the rated closure flow rate specified by the manufacturer and upon closure, reduce the gas flow to the level indicated:
      (i) for an excess flow valve designed to allow pressure to equalize across the valve, no more than 5% of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet (0.566 cubic meters) per hour; or
      (ii) for an excess flow valve designed to prevent equalization of pressure across the valve, no more

than 0.4 cubic foot (0.011 cubic meters) per hour; and

§255.383 Excess flow valve customer [notification]installation.

(a) Definitions. As used in this section:

[(1) Costs associated with installation means the costs directly connected with installing an excess flow valve, for example, costs of parts, labor, inventory and procurement. It does not include maintenance and replacement costs until such costs are incurred.]

([2]1) Replaced service line means a [natural]gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

(2) Service line serving single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

(b) Installation required. An excess flow valve (EFV) installation must comply with the performance standards in section 255.381. The operator must install an EFV on any new or replaced service line serving a single-family residence unless one or more of the following conditions is present:

(1) The service line does not operate at a pressure of 10 PSIG (69 kPa) or greater throughout the year;

(2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV operation or cause loss of service to a residence;

(3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or

(4) An EFV meeting performance standards in section 255.381 is not commercially available to the operator.

(c) Reporting. Each operator must, on an annual basis, report the number of EFVs installed pursuant to section 255.383 as part of the annual report required by 49 CFR 191.11.

[(3) Service line customer means the person who pays the gas bill, or where service has not yet been established, the person requesting service.

(b) An operator of a natural gas distribution system must notify each customer of a newly installed or replaced service line that operates continuously throughout the year at a pressure not less than 68.9 kPa (10 psig) and that serves a single residence that an excess flow valve may be installed.

(c) The written notice must include:
- (1) an explanation that an excess flow valve meeting the performance standards prescribed under section 255.381 of this Part is available for the operator to install if the customer bears the costs associated with installation;
- (2) an explanation of the potential safety benefits that may be derived from installing an excess flow valve. The explanation must include that an excess flow valve is designated to shut off the flow of natural gas automatically if the service line breaks;
- (3) a description of installation, maintenance, and replacement costs. The notice must explain that if the customer requests the operator to install an excess flow valve, the customer bears all costs associated with installation and what those costs are. The notice must alert the customer that costs for maintaining and replacing an excess flow valve may later be incurred, and what those costs will be, to the extend known.

(d) If a service line customer requests installation of an excess flow valve, an operator must install the excess flow valve at a mutually agreeable date.

(e) An operator must make the following records available for inspection by the Office of Gas and Water of the Department of Public Service:
- (1) a copy of the notice currently in use; and
- (2) evidence that notice has been sent to the service line customers set forth in subdivision (b) of this section, within the previous three years.

(f) Notification requirements do not apply if the operator can demonstrate that:
- (1) the operator will voluntarily install an excess flow valve or that the State or local jurisdiction requires installation;
- (2) excess flow valves meeting the performance standards in section 255.381 of this Part are not available to the operator;
- (3) the operator has prior experience with containments in the gas stream that could interfere with the operation of an excess flow valve, cause loss of service to a residence, or interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or
- (4) an emergency or short time notice replacement situation made it impractical for the operator to notify a service line customer before replacing a service line.]

§255.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(b) An operator need not comply with subdivision (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.

(1) 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 (6.1 meters), and soil resistivity measurement at all potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline.

§255.457 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, or distribution main to be operated at a pressure of 125 PSIG (862 kPa) or more in a Class 3 or 4 location, installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated. For the purposes of this Part, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

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

(3) bare or coated distribution lines, except coated distribution mains to be operated at a pressure of 125 PSIG (862 kPa) or more in a Class 3 or 4 location.

§255.461 External corrosion control: Protective coating.

(d) Electrical tests appropriate for the type of coating shall be used on pipelines to operate at 125 PSIG (862 kPa) or more to detect defects in the coating which may not be revealed by a visual inspection. Where such tests are not practical, electrical tests, after installation, shall be conducted.

§255.465 External corrosion control: Monitoring.

(a) Pipe-to-soil electrical potential tests or other acceptable electrical tests shall be conducted over each pipeline 100 feet (30.5 meters), or longer that is under cathodic protection at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of section 255.463. These should also be conducted for pipelines shorter than 100 feet (30.5 meters). However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30.5 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis.

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but at intervals not exceeding 2 1/2 months, to [insure]ensure that it is operating.

§255.467 External corrosion control: Electrical isolation.

(g) For any pipeline constructed after December 1, 1993, that is located parallel and in close proximity to or crosses underneath an overhead high-voltage (69 kV or higher) electric transmission facility, the step and touch voltages induced by magnetic fields of overhead electric lines under steady state conditions shall be limited to 15 volts or less at all points where a person could normally touch the pipeline or a pipeline appurtenance. This does not apply to buried pipelines or to locations where access is limited by use of fences or barriers to personnel that are trained in safe practices regarding step and touch voltages. The short term emergency loading condition of the circuit as defined by the [New York Power Pool]New York Independent System Operator for the electric facility shall be used in determining the magnitude of the step and touch voltages.

§255.476 Internal corrosion control: Design and construction of transmission line.

(a) Design and construction. Except as provided in paragraph (b) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must have features incorporated into its design and construction to reduce the risk of internal corrosion. At a minimum, unless it is impracticable or unnecessary to do so, each new transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line must:

(1) Be configured to reduce the risk that liquids will collect in the line;

(2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and

(3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) Exceptions to applicability. The design and construction requirements of paragraph (a) of this section do not apply to pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

(c) Change to existing transmission line. When an operator changes the configuration of a transmission line, the operator must evaluate the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

(d) Records. An operator must maintain records demonstrating compliance with this section. Provided the records show why incorporating design features addressing paragraph (a)(1), (a)(2), or (a)(3) of this section is impracticable or unnecessary, an operator may fulfill this requirement through written procedures supported by as-built drawings or other construction records.

§255.505 Strength test requirements for steel pipelines to operate at 125 PSIG (862 kPa) or more.

(a) Each segment of a steel pipeline that is to operate at a pressure of 125 PSIG (862 kPa) or more must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure.

(c) The test medium may be water, inert gas or air. For facilities to be operated above 20 percent SMYS in any class location or facilities to be operated at 125 PSIG (862 kPa) or more in a Class 4 location the medium may only be water unless there are no buildings intended for human occupancy within 300 feet (91.4 meters) of the pipeline facilities being tested and prior approval is granted by the [Gas and Water Division]Department to use air or inert gas as the test medium.

(e) A calibrated recording pressure gauge that will indicate increments of 5 PSIG (34.5 kPa) or less, where practicable, shall be attached to the test section. The gauge must be calibrated at least hourly for the first and last two hours of the test. Calibration is against a dead-weight tester, or equivalent device, attached to the test section.

(i) Tests under this section are not considered as satisfactorily accomplished unless certified by an inspector of the [Gas and Water Division of the New York State Department of Public Service]Department.

§255.507 Test requirements for pipelines to operate at less than 125 PSIG (862 kPa).

(a) Except for service lines, each segment of a pipeline that is to be operated at less than 125 PSIG (862 kPa) must be tested in accordance with this section.

(b) The test pressure shall be 90 PSIG (621 kPa) or 1.5 times the maximum operating pressure whichever is greater; however, the maximum test pressure for plastic pipelines may not be more than 3 times the design pressure for the pipe determined under section 255.121 of this Part, at a temperature not less than the pipe temperature during the test. During the test, the temperature of thermoplastic material may not be more than 100 degrees F (38 °C), or the temperature at which the material's long term hydrostatic strength has been determined under the listed specification, whichever is greater.

(e) A calibrated pressure gauge that will indicate increments of 2 PSIG (14 kPa) or less shall be attached to the test section.

(f) For tests on short sections (100 feet (30.5 meters) or less) of pipe, and tie-in sections, where all joints, uncoated portions of longitudinal seams, and/or fittings are exposed, a soap test is acceptable at line pressure. For short sections of plastic pipe, the entire pipe length must be soap tested. Gas may be used as the test medium at the maximum pressure available in the distribution system at the time of the test.

(g) For plastic insertions of less than 1500 feet (457.2 meters) length, the test duration may be 30 minutes prior to insertion followed by a 30 minute test after insertion and an inspection of all visible portions of the pipe for damage.

§255.511 Test requirements for service lines.

(a) Except for steel service lines greater than two inches (51 millimeters) in nominal diameter that are to operate at 125

PSIG (862 kPa) or more, each segment of a service line must be leak tested in accordance with this section before being placed into service.

(b) Steel service lines greater than two inches (51 millimeters) in nominal diameter that are to operate at 125 PSIG (862 kPa) or more must be tested in accordance with sections 255.505(a) through (f) of this Part.

(c) Except for copper service lines, the test pressure shall be 90 PSIG (621 kPa) or 1.5 times the maximum operating pressure, whichever is greater; however, the maximum test pressure and material temperature during the test must be in accordance with section 255.507(b) of this Part.

(d) For copper service lines, the test pressure shall be 50 PSIG (345 kPa) or 1.5 times the maximum operating pressure, whichever is greater; however, the maximum test pressure may not be more than 3 times the design pressure for the pipe

(f) The test duration shall be as follows:
   (1) for service lines 2 inches (51 millimeters) and smaller to operate at less than 125 PSIG (862 kPa), 15 minutes;
   (2) for service lines 2 inches (51 millimeters) and smaller to operate at 125 PSIG (862 kPa) or more, two hours; or
   (3) for service lines greater than 2 inches (51 millimeters), to operate at less than 125 PSIG (862 kPa), 30 minutes.

(i) The test indicator for service line tests shall be a calibrated pressure gauge marked in 5 PSIG (34.5 kPa) increments for service lines to operate at 100 PSIG (689 kPa) or more. For tests on lines to operate at less than 100 PSIG (689 kPa), the test indicator must be such that any loss of pressure can be readily detected.

§255.515 Environmental protection and safety requirements.

(a) In conducting tests under this Part, each operator shall [insure]ensure that every reasonable precaution is taken to protect its employees and the general public during the testing. The operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

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

§255.552 Notification requirements.

(a) The maximum allowable operating pressure of any transmission line, or main operating at a pressure of 125 PSIG (862 kPa) or above, shall not be raised or lowered without submitting a letter of intent at least 60 days prior to any proposed change of said certified pressure. Where the letter of intent indicates a decrease in the maximum allowable operating pressure, a statement of explanation is to be included. All procedures involved in the recertification project shall be in accordance with these requirements. In the event of an emergency, verbal permission may be obtained, but the written application must be filed promptly.

(b) In addition, any operator proposing to increase the maximum allowable operating pressure of a pipeline which was originally constructed to operate at a pressure of less than 125 PSIG (862 kPa) to a pressure of 125 PSIG (862 kPa) or more shall comply with the reporting requirement of subdivision 255.552(a). If the increase in pressure is proposed within three years of the initial operation of a pipeline which, at the higher pressure proposed, would fall within the definition of "major utility transmission facility" as set forth in Section 120(2) of the Public Service Law, a hearing will be held on the proposed increase, unless such hearing is waived by the Commission on the application of staff of the [Gas and Water Division]Department. In addition with respect to any such increase, the operator shall, in addition to the reporting requirements set forth above, provide in writing to staff the basis of the need for the increase, a discussion of how the increase will serve the public interest, convenience and necessity, and such assurance as staff may require, including documentation, that no undue hazard will result from operation of the line at the higher pressure.

(c) At least 60 days prior to increasing the maximum allowable operating pressure of a distribution system above the limits set below, the operator shall submit a letter of intent. In the event of an emergency, verbal permission may be obtained, but the written notification must be filed promptly.

(1) If the maximum allowable operating pressure is between 1/2 PSIG (3.4 kPa) and 60 PSIG (414 kPa), notice is required for an increase in pressure greater than 6 PSIG (41.4 kPa).

(2) If the maximum allowable operating pressure is between 60PSIG (414 kPa) and 124 PSIG (855 kPa), notice is required for an increase in pressure greater than 10% of the maximum allowable operating pressure.

(3) Converting a low pressure distribution system to a high pressure system not to exceed 124 PSIG (855 kPa).

§255.555 Upgrading to a pressure of 125 PSIG (862 kPa) or more in steel pipelines.

(a) Unless the requirements of this section have been met, no person may subject any segment of a steel pipeline to a pressure that is 125 PSIG (862 kPa) or more and that is above the established maximum allowable operating pressure.

(b) Before increasing the operating pressure above the previously established maximum allowable operating pressure the operator shall comply with the following requirements.

(5) Where nondestructive testing is required, the operator shall select welds within 150 feet (45.72 meters) of habitable structures until the minimum percentage is achieved.

§255.557 Upgrading to a pressure less than 125 PSIG (862 kPa).

(a) Unless the requirements of this section have been met, no person may subject a segment of steel or plastic pipeline to a higher maximum allowable operating pressure that is less than 125 PSIG (862 kPa).

(d) After complying with subdivision (c) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 PSIG (69 kPa) or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (c)(8) of this section apply, there must be at least two approximately equal incremental increases

§255.605 Essentials of operating and maintenance plan.

(s) Implementing the applicable control room management procedures required by section 255.631.

§255.615 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:

(11) Actions required to be taken by a controller during an emergency in accordance with section 255.631.

§255.616 Customer education and information program.

(a) Except for an operator of a petroleum gas system covered under paragraph (j) of this section, e[E]ach pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (as described in section 10.3 of the Title).

(h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. As an exception, operators of petroleum gas or petroleum gas/air distribution systems having less than 25 customers must have completed development and documentation of their programs no later than June 20, 2007. The operator of a petroleum gas system covered under paragraph (j) of this section must complete development of its written procedure by June 13, 2008.

(j) Unless the operator transports gas as a primary activity, the operator of a petroleum gas system is not required to develop a public awareness program as prescribed in paragraphs (a) through (g) of this section. Instead the operator must develop and implement a written procedure to provide its customers public awareness messages twice annually. If the petroleum gas system is located on property the operator does not control, the operator must provide similar messages twice annually to persons controlling the property. The public awareness message must include:

(1) A description of the purpose and reliability of the pipeline;
(2) An overview of the hazards of the pipeline and prevention measures used;
(3) Information about damage prevention;
(4) How to recognize and respond to a leak; and
(5) How to get additional information

(k) In addition, the program shall include annual distribution of plain language literature, news releases and commercial messages to advise the public of the importance of the inspection and cleaning of flues and chimneys on a periodic basis, regardless of the fuel used (particularly whenever converting to [natural]gas usage), and to provide information on identifying symptoms of carbon monoxide exposure including recommended remedial measures.

§255.619 Maximum allowable operating pressure: Steel or plastic pipelines.

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

(ii) for steel pipe operated at 100 PSIG (689 kPa) or more, the test pressure is divided by a factor determined in accordance with the following table:

§255.621 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:

(2) 60 PSIG (414 kPa), for a segment of a distribution system otherwise designated to operate at over 60 PSIG (414 kPa), unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of subdivision 255.197(c);

(3) 25 PSIG (172 kPa) in segments of cast iron pipe in which there are unreinforced bell and spigot joints;

§255.623 Maximum and minimum allowable operating pressure: Low pressure distribution systems.

(d) The maximum daily pressure variation shall not exceed a total range of 50 percent of the maximum gauge pressure experienced during the day at any point in the low pressure distribution system, as measured at the consumer's end of the service line. Overpressure protection devices may be set at levels above the normal maximum operating pressure. The capacity of overpressure protection devices shall be sufficient to prevent a pressure buildup in excess of 2 PSIG (14 kPa) on the low pressure distribution system.

§255.625 Odorization of gas.

(a) All gas transported in transmission lines, and distribution mains operating at 125 PSIG (862 kPa) or more, except gas in route to storage fields, is to be adequately odorized in compliance with subdivision 255.625(c) so as to render it readily detectable by the public and employees of the operator at all gas concentrations of one fifth of the lower explosive limit and above.

(d) Odorization equipment must be designed and maintained so as to [insure]ensure the required odorant level in the gas under varying conditions. The equipment must be installed so that it does not cause a nuisance to nearby residents by the escape of odorant fumes.

§255.631 Control room management.

(a) General.

(1) This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section, except that for each control room where an operator's activities are limited to either or both of:

(i) Distribution with less than 250,000 services, or

(ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue) and (i) (regarding compliance and deviations) of this section.

(2) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by sections 255.605 and 255.615. An operator must develop the procedures no later than August 1, 2011 and implement the procedures no later than February 1, 2013.

(b) Roles and responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) A controller's authority and responsibility to make decisions and take actions during normal operations;

(2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and to communicate with others; and

(4) A method of recording controller shift-changes and any hand- over of responsibility between controllers.

(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (as described in Section 10.3 of this Title),

whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

(3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;

(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and

(5) Establish and implement procedures for when a different controller assumes responsibility, including the content of information to be exchanged.

(d) Fatigue mitigation. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:

(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;

(2) Educate controllers and supervisors in fatigue mitigation strategies and how off-duty activities contribute to fatigue;

(3) Train controllers and supervisors to recognize the effects of fatigue; and

(4) Establish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility.

(e) Alarm management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:

(1) Review SCADA safety-related alarm operations using a process that ensures alarms are accurate and support safe pipeline operations;

(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for

periods of time exceeding that required for associated maintenance or operating activities;

(3) Verify the correct safety-related alarm set-point values and alarm descriptions at least once each calendar year, but at intervals not to exceed 15 months;

(4) Review the alarm management plan required by this paragraph at least once each calendar year, but at intervals not exceeding 15 months, to determine the effectiveness of the plan;

(5) Monitor the content and volume of general activity being directed to and required of each controller at least once each calendar year, but at intervals not to exceed 15 months, that will assure controllers have sufficient time to analyze and react to incoming alarms; and

(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.

(f) Change management. Each operator must assure that changes that could affect control room operations are coordinated with the control room personnel by performing each of the following:

(1) Establish communications between control room representatives, operator's management, and associated field personnel when planning and implementing physical changes to pipeline equipment or configuration;

(2) Require its field personnel to contact the control room when emergency conditions exist and when making field changes that affect control room operations; and

(3) Seek control room or control room management participation in planning prior to implementation of significant pipeline hydraulic or configuration changes.

(g) Operating experience. Each operator must assure that lessons learned from its operating experience are incorporated, as appropriate, into its control room management procedures by performing each of the following:

(1) Review incidents that must be reported pursuant to 49 CFR part 191 to determine if control room actions contributed to the event and, if so, correct, where necessary, deficiencies related to:

(i) Controller fatigue;

(ii) Field equipment;

(iii) The operation of any relief device;

(iv) Procedures;

(v) SCADA system configuration; and

(vi) SCADA system performance.

(2) Include lessons learned from the operator's experience in the training program required by this section.

(h) Training. Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

(2) Use of a computerized simulator or non-computerized (tabletop) method for training controllers to recognize abnormal operating conditions;

(3) Training controllers on their responsibilities for communication under the operator's emergency response procedures;

(4) Training that will provide a controller a working knowledge of the pipeline system, especially during the development of abnormal operating conditions; and

(5) For pipeline operating setups that are periodically, but infrequently used, providing an opportunity for controllers to review relevant procedures in advance of their application.

(i) Compliance and deviations. An operator must maintain for review during inspection:

(1) Records that demonstrate compliance with the requirements of this section; and

(2) Documentation to demonstrate that any deviation from the procedures required by this section was necessary for the safe operation of a pipeline facility.

§255.703 General.

(c) The provisions of: sections 255.705, 255.706, 255.709, 255.711, 255.713, 255.715, 255.717, and 255.719 shall pertain, as applicable, to all transmission lines, and all distribution mains operating at 125 PSIG (862 kPa) or more in Class 3 and 4 locations.

§255.705 Transmission lines: Patrolling.

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to transmission line rights-of-way, and distribution line rights-of-way where the distribution line operates at 125 PSIG (862 kPa) or more in a Class 3 or 4 location, for indications of leaks, construction activity, and other factors affecting safety and operation.

§255.706 Transmission lines: Leakage surveys.

(a) A leakage survey of each transmission line, and distribution main operating at 125 PSIG (862 kPa) or more in a Class 3 or 4 location, must be conducted at intervals not exceeding 15 months, but at least once each calendar year.

§255.709 Transmission lines: Record keeping.

Each operator shall keep records covering each leak discovered, repair made, and line break for as long as the segment of transmission line, or distribution main operating at 125 PSIG (862 kPa) or more in a Class 3 or 4 location, involved remains in service. (See section 255.17 of this Part.)

§255.711 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, or distribution main operating at 125 PSIG (862 kPa) or more in a Class 3 or 4 location; and

§255.715 Transmission lines: Permanent field repair of welds.

Each weld that is unacceptable under subdivision 255.241(c) must be repaired according to the following requirements.

(a) If it is feasible to take the segment of transmission line, or distribution main operating at 125 PSIG (862 kPa) or more in a Class 3 or 4 location, out of service, the weld must be repaired in accordance with the applicable requirements of section 255.245.

§255.717 Transmission lines: Permanent field repair of leaks.

Each permanent field repair of a leak on a transmission line, or distribution main operating at 125 PSIG (862 kPa) or more in a Class 3 or 4 location, must be made according to the following requirements.

§255.719 Transmission lines: Testing of repairs.

(a) If a segment of transmission line, or distribution main operating at 125 PSIG (862 kPa) or more in a Class 3 or 4 location, 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.

§255.721 Distribution systems: Patrolling.

(c) Distribution lines operating at 125 PSIG (862 kPa) or more in Class 3 and 4 locations must comply with the transmission patrolling requirements in section 255.705

§255.723 Distribution systems: Leakage surveys and procedures.

(c) Distribution lines operating at 125 PSIG (862 kPa) or more and located in Class 3 and 4 locations must comply with the transmission line leakage survey requirements in section 255.706.

§255.725 Test requirements for reinstating service lines.

(b) For each service line to be operated at a pressure of not more than 20 PSIG (138 kPa), the test pressure shall be 3 PSIG (21 kPa) or 3 times the maximum allowable operating pressure, whichever is greater.

(c) For each service line to be operated at more than 20 PSIG (138 kPa) but not more than 60 PSIG (414 kPa), the test pressure shall be 90 PSIG (621 kPa).

(d) For each service line to be operated at more than 60 PSIG (414 kPa), the test pressure shall be 1.5 times the maximum allowable operating pressure.

§255.726 Inactive service lines.

[(a)] All inactive service lines, including stubs, must be inspected, leakage surveyed and maintained according to the applicable provisions of this Part. Inactive steel service lines not under cathodic protection, including stubs, may remain under the conditions established by subdivision 255.727(d) for a period of not more than six years subject to the following conditions:

([b]a) During the third year of inactivity, the operator must conduct a survey for potential future use and, if there is no definite plan for future use, disconnect the service at the main or in compliance with subdivision 255.726(d), purge the service and seal the open end.

([c]b) Inactive service lines for which there is a definite plan for future use may remain under the conditions established by subdivision 255.727(d) for an additional three year period provided the operator either reactivates the service or disconnects the service at the main or in compliance with subdivision 255.726(d), purges the service and seals the open ends by the end of the sixth year of inactivity.

([d]c) Whenever the service connection to the main is located under pavement, an inactive service line may be disconnected in an unpaved area but no closer than 10 feet (3 meters) to the building subject to the following requirements.

(1) Records of inactive service stubs shall be maintained and the locations of these facilities shall be clearly noted on maps or records of the gas distribution system. This information will be used in marking these facilities prior to third party excavation activities and for use in leakage survey and leakage investigation procedures.

(2) Any steel service stub shall have an appropriately sized sacrificial anode attached consistent with good cathodic protection practices.

([e]d) Whenever an inactive service line or service stub is exposed at the main in association with other operation, maintenance, or construction activities, it must be disconnected at the main, purged, and the open end sealed unless there is a definite plan for future use.

([f]e) Whenever an inactive service line or service stub is found to be leaking or is damaged, it must be disconnected at the main, purged, and the open end sealed.

§255.727 Abandonment or inactivation of facilities.

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

§255.736 Compressor stations: Gas detection.

(a) Each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is:

(2) Located in an unattended field compressor station of 1,000 horse-power (746 kW) or less.

§255.749 Vault maintenance.

(a) Each vault housing pressure regulating and pressure limiting equipment, and having a volumetric internal content of 200 cubic feet (5.66 cubic meters) or more, must be inspected at intervals not exceeding 15 months, but at least once each calendar year, to determine that it is in good physical condition and adequately ventilated.

§255.756 Replacement of exposed or undermined cast iron piping.

(a) When any cast iron pipe, eight inches or less in nominal diameter, has been or will be exposed and undermined by an excavation 36 inches (914 millimeters) or greater in width, the purpose of which is for work other than normal gas operation and maintenance work being performed on the exposed cast iron main, one of the following actions must be taken in the listed order of preference

§255.811 Leaks: Type 1 classification.

(e) Type 1 leaks include, but are not limited to:
   (3) any reading on a CGI within five feet (1.5 meters) of a building wall;

§255.813 Leaks: Type 2A classification.

(d) Type 2A leaks include, but are not limited to:
   (1) any reading of 10 percent or greater gas-in-air in any area continuously paved from the curb to the building wall, which is more than five feet (1.5 meters) but within 30 feet (9.1 meters) of the building and inside the curbline or shoulder of the road;
   (2) any reading, in an unpaved area, of 20 percent or greater gas-in-air which is more than 5 feet (1.5 meters) but within 20 feet (6.1 meters) of the building and inside the curb or shoulder of the road;

§255.815 Leaks: Type 2 classification.

(d) Type 2 leaks include, but are not limited to:
   (1) any reading less than 10 percent gas-in-air between the building and the curbline in any area continuously paved which is more than five feet (1.5 meters)but within 30 feet (9.1 meters) of the building and inside the curbline or shoulder of the road; or
   (2) any reading less than 20 percent gas-in-air in any unpaved area which is more than five feet (1.5 meters)

from but within 20 feet (6.1 meters) of a building and inside the curbline or shoulder of the road; or

(3) any reading of 30 percent or greater gas-in-air in an unpaved area which is more than 20 feet (6.1 meters) from but within 50 feet (15.2 meters) of a building and inside the curbline or shoulder of the road; or

(4) any reading of 30 percent or greater gas-in-air in a paved area which is more than 30 feet (9.1 meters) from but within 50 feet (15.2 meters) of a building and inside the curbline or shoulder of the road; or

§255.827 Facility failure investigation.

(b) The procedures shall also provide for complete cooperation with the [Gas and Water Division]Department staff, in testing or surveying, including using independent consultants, any equipment or systems deemed necessary by staff for the investigation and analysis of any failure or accident to determine its cause and to minimize the possibility of recurrence.

§255.903 Definitions.

(d) [*Department* refers to the New York State Department of Public Service – Office of Gas and Water.

(e)]*Direct assessment ...*

([f]e) *High consequence area ...*

([g]f) *Identified site ...*

([h]g) *Potential impact circle ...*

([i]h) *Potential impact radius* (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69*(square root of $(p*d^2)$), where ‘r’ is the radius of a circular area in feet surrounding the point of failure, ‘p’ is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and ‘d’ is the nominal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S[–2001] (as described in section 10.3 of this Title) to calculate the impact radius formula.

([j]i) *Remediation ...*

§255.923 Direct Assessment.

(b) *Primary method*. An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

(1) ASME/ANSI B31.8S (as described in section 10.3 of this Title), section 6.4; NACE RP 0502[–2002] (as described in section 10.3 of this Title); and section 255.925 of this Part if addressing external corrosion (ECDA).

§255.925 External Corrosion Direct Assessment (ECDA).

(a) *Definition*. ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (as described in section 10.3 of this Title), section 6.4, and in NACE RP 0502[–2002] (as described in section 10.3 of this Title). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (section 255.917(b) of this Part) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by section 255.917(e)(1)of this Part.

(1) *Preassessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502[–2002], section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE RP 0502[–2002], the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502[–2002], section 4, the plan's procedures for indirect examination of the ECDA regions must include—

(a) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;
(i) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;
(ii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and
(iii) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502[–2002], section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;
(ii) Criteria for deciding what action should be taken if either:
  (A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP 0502[–2002]), or
  (B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP 0502[–2002]);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE RP 0502[–2002].

(4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP 0502[–2002], section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in section 255.939 of this Part. (See Appendix D of NACE RP 0502[–2002].)

§255.931 Confirmatory Direct Assessment (CDA).

(d) *Defects requiring near-term remediation*. If an assessment carried out under subdivision (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE RP 0502[–2002] (as described in section 10.3 of this Title), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with section 255.933 of this Part until the operator has completed reassessment using one of the assessment techniques allowed in section 255.937 of this Part.

§255.933 Addressing Integrity Issues.

(2) One-year conditions. Except for conditions listed in paragraphs (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches (13 millimeters) in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches (6 millimeters) in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) Monitored conditions. An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches (13 millimeters) in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).

(ii) dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches (13 millimeters) in depth for a pipeline diameter less than Nominal Pipe Size(NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches (6 millimeters) in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

§255.935 Preventive and Mitigative Measures to Protect the High Consequence Areas.

(b) *Third party damage and outside force damage—*

(1) *Third party damage*. An operator must enhance its damage prevention program, as required under section 255.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures

to an existing damage prevention program include, at a minimum—

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP 0502[–2002] (as described in section 10.3 of this Title). An operator must excavate, and remediate, in accordance with ANSI/ ASME B31.8S and section 255.933 of this Part any indication of coating holidays or discontinuity warranting direct examination.

§255.939 Reassessment Intervals.
An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(2) *External Corrosion Direct Assessment*. An operator that uses ECDA that meets the requirements of sections 255.901 through 255.951 of this Part must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE RP 0502[–2002] (as described in section 10.3 of this Title).