PART 255

TRANSMISSION AND DISTRIBUTION OF GAS
(Statutory authority: Public Service Law, §§ 4, 65, 66)

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255.1 Scope.
   (a) This Part prescribes minimum safety requirements for the design, fabrication, installation, inspection, testing and operation and maintenance of gas transmission and distribution systems, including gas gathering lines, gas pipelines, gas compressor stations, gas metering and regulating stations, gas mains, service lines, gas storage equipment of the closed pipe type fabricated or forged from pipe or fabricated from pipe and fittings, and gas storage lines not covered by 49 CFR 192.
   (b) Every person engaged in the transportation of gas via pipeline within the State of New York shall comply with the rules set forth in this Part.
   (c) This Part is based on and includes many of the requirements set forth in title 49, Code of Federal Regulations, part 192 Department of Transportation Regulations for Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards. The rules and regulations expressed or implied by this Part meet or exceed those Minimum Federal Safety Standards.
   (d) This Part does not apply to:
      (1) design and fabrication of pressure vessels covered by the ASME Boiler and Pressure Vessel Code;
      (2) piping with metal temperatures above 450µF (232µC) or below minus 20µF (-29µC);
      (3) the design, fabrication and installation of aboveground or inside piping and appliances beyond the outlet of the customer's meter set.
assembly (refer to Part 261 and NFPA 54);
(4) piping in oil refineries or natural gasoline extraction plants, gas treating plant piping other than the main gas stream piping in dehydration and all other processing plants installed as part of the gas transmission system, gas manufacturing plants, industrial plants or mines;
(5) vent piping to operate at substantially atmospheric pressures for waste gases of any kind;
(6) wellhead assemblies, including traps or separators, heaters, control valves, and flow lines of less than 100 feet (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);
(7) proprietary items of equipment, apparatus or instruments;
(8) heat exchangers;
(9) liquid petroleum transportation piping systems; and
(10) prefabricated units which employ plate and longitudinal welds as contrasted to pipe.
(11) any pipeline that transports only petroleum gas or petroleum gas/air mixtures to
(i) fewer than 10 customers, if no portion of the system is located in a public place; or
(ii) a single customer, if the system is located entirely on the customer's premises.

NYCRR 255.2 Retroactivity. (a) Except where otherwise indicated, this Part will not be applied retroactively to existing installations insofar as design, fabrication, installation and testing are concerned.
(b) However, all the provisions of this Part will be applicable to any recertification, upgrading, or reconstruction. Recertifications and upgradings are also specifically subject to the provisions of sections 255.552 through 255.557 of this Part.
(c) Existing installations will conform to the requirements of this Part's predecessor in effect at the time of installation.
(d) Provisions of this Part are applicable to the operation and maintenance of existing and new installations.

NYCRR 255.3 Definitions.
(a) As used in this Part:
(1) Approved means prior approval must be granted by the Department, except in emergency situations.
(2) Building of public assembly means any school, hospital, nursing home, institution licensed by New York State for the care of children, or any factory which normally employs 75 or more persons; or any other building with a nominal capacity of 75 or more persons to which the public is regularly admitted. Structures which are used solely as office buildings or residential apartments and normally have no other utilization in excess of the 75-person limit are excluded from this definition.
(3) Distribution line means a pipeline other than a gathering or transmission line.
(4) Field regulator means a pressure regulating device with an outlet pressure in pounds per square inch serving two through ten residential
gas customers. This regulator is also known as a farm tap regulator.

(5) Follow-up inspection means an inspection performed after an outside leak repair procedure has been completed in order to determine the effectiveness of the repair. It includes retests of all positive inside leak indications and outside readings from the original classification.

(6) Gas means natural gas or other fuel gas, including liquefied petroleum gas distributed as a vapor.

(7) Gathering line means a pipe line that transports gas from a current production facility to a transmission line, main, or directly to an end user.

(8) High pressure distribution system means a distribution system in which the gas pressure in the main must be reduced before delivery to a customer.

(9) Hoopstress means the stress in a pipewall, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe and produced by the pressure of the fluid in the pipe.

(10) Hot tap means a branch piping connection made to an operating pipeline or other facility while it is under gas pressure.

(11) Leakage investigation means a survey conducted for the purpose of determining the extent of potential hazard and classifying a leak in accordance with section 255.807 of this Part. It involves the driving or boring of holes at sufficient depth and testing the atmosphere in these holes and other available openings with a properly calibrated combustible gas indicator (CGI) or approved equivalent device.

(12) Leakage survey means a systematic survey made for the purpose of locating leaks in a gas piping system using an approved instrument which continuously analyzes atmospheric samples near ground level and is capable of detecting the presence of gas in parts per million in air.

(13) Listed specification means a specification set forth in section I of Appendix 14-B of this Title.

(14) Long-term hydrostatic strength means the estimated hoop stress in psi in a plastic pipe wall that will cause failure of the pipe at an average of 100,000 hours when subjected to a constant hydrostatic pressure.

(15) 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 typical customer.

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

(17) Maximum actual operating pressure means the maximum pressure that occurs on a system during normal operations over a period of one year.

(18) Maximum allowable operating pressure means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this Part.

(19) Maximum certified operating pressure means the maximum pressure at which a pipeline may be operated, as certified by the original filing under section 255.302(b) of this Part, a predecessor rule thereof, or as modified in accordance with section 255.555 or 255.611 of this Part.

(20) Municipality means a city, county, or other political subdivision of New York State.

(21) Operator means a person who engages in the transportation of gas.

(22) Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association,
or joint stock association, and including any trustee, receiver, assignee or personal representative thereof.

(23) Pipe means any pipe or tubing used in the transportation of gas.

(24) Pipeline means all parts of those physical facilities through which gas is transported, including pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

(25) Pipeline facility means new and existing pipeline, 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.

(26) Plastic means a material which contains as an essential ingredient one or more organic polymeric substances of large molecular weight, is solid in its finished state and, at some stage of its manufacture or processing, can be shaped by flow. The two general types of plastic referred to in this Part are thermoplastic and thermosetting.

(27) Reading means any sustained deviation on a properly calibrated combustible gas indicator (CGI) or approved equivalent instrument taken in a sample point expressed in percent LEL (lower explosive limit) or percent gas-in-air;

(28) Secondary stress means stress created in the pipe wall by loads other than internal fluid pressure. For example, backfill loads, traffic loads, beam action in a span, loads at supports and at connections to the pipe;

(29) Service line means the piping, including associated metering and pressure reducing appurtenances, that transports gas below grade from a main or transmission line to the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream where a meter is located within the building; if a meter is located outside the building, the service line will be deemed to terminate at the outside of the building foundation wall.

(30) SMYS means specified minimum yield strength.

(31) Stub means a service line that terminates at or before the property line.

(32) Thermoplastic means a plastic which is capable of being repeatedly softened by increase of temperature and hardened by decrease of temperature.

(33) Thermosetting plastic means a plastic which is capable of being changed into a substantially infusible or insoluble product when cured by application of heat or chemicals.

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

(i) transports gas from a gathering line or storage facility to a distribution center, storage facility, or directly to a large volume user that is not downstream from a distribution center; or

(ii) operates at a hoop stress of 20 percent or more of SMYS; or

(iii) transports gas within a storage field.

Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

(35) Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas.

(36) Excess flow valve means a device installed in or near the service tee to prevent gas from flowing downstream in the event of failure of
the service between the tee and meter. When the gas flow through the
device exceeds a designated rate, the valve automatically closes and
stops all or a major portion of the gas flow.

(37) Abnormal operating condition means a condition identified by the
operator that may indicate a malfunction of a component or deviation
from normal operations that may indicate a condition exceeding design
limits or result in a hazard(s) to persons, property, or the
environment.

(38) Evaluation means a process, established and documented by the
operator, to determine an individual's ability to perform a covered task
by any of the following: written examination; oral examination; work
performance history review; observation during (a) performance on the
job, (b) on the job training, (c) simulations; or other forms of
assessment.

(39) Qualified means that an individual has been evaluated and can (a)
perform assigned covered tasks and (b) recognize and react to abnormal
operating conditions.

(40) Covered tasks are activities, identified by the operator, that
(a) are performed on a pipeline facility, (b) are operations and
maintenance tasks, (c) are performed as a requirement of this part and
(d) affect the operation or integrity of the pipeline.

(41) Abandoned means permanently removed from service.

(42) Customer meter means the meter that measures the transfer of gas
from an operator to a consumer.

(43) Service regulator means the device on a service line that
controls the pressure of gas delivered from a higher pressure to the
pressure provided to the customer. A service regulator may serve one
customer or multiple customers through a meter header or manifold.

(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.ny.gov.

(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.

(49) Active corrosion means continuing corrosion that, unless
controlled, could result in a condition that is detrimental to public
safety.

(50) Electrical survey means a series of closely spaced pipe-to-soil
readings over pipelines which are subsequently analyzed to identify
locations where a corrosive current is leaving the pipeline.

(51) Pipeline environment includes soil resistivity (high or low),
soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

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 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 one-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.

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

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

(d) A Class 3 location is:

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

(2) any 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).

(e) A Class 4 location is:

(1) any class location unit that has 100 or more buildings intended for human occupancy and where wall to wall pavement is prevalent; or

(2) any class location unit where buildings with four or more stories aboveground are prevalent.

(f) The boundaries of the class location unit determined in accordance with subdivisions (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.

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

(b) All incorporated documents are available for inspection 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).

(c) The full titles for the publications incorporated by reference in this Part are provided in section 10.3 of this Title. Numbers in
Gathering lines.

(a) Except as specified in subdivision (b) of this section, each gathering line shall be designed, constructed, tested, operated and maintained as specified in subdivision (f) of this section.

(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;
2. within the limits of any city, or incorporated village; or
3. within a designated residential or commercial area such as a subdivision, business or shopping center, or community development.

(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.
3. Any person intending to construct a gathering line in an area used for commercial farm purposes in at least two of the last five years regardless of the proposed operating pressure of the line, must complete the information requested in Appendices 7-G and 7-G(a) of this Title and provide one copy each of Appendices 7-G and 7-G(a) of this Title to the affected farmland operator and the local county soil and water conservation district at least 48 hours in advance of the start of construction. The person shall retain a copy of Appendices 7-G and 7-G(a) of this Title for review by any interested party in the future.

(d) Notwithstanding any other provisions of this Part, where natural gas is gathered from production facilities, transported off the property on which the production facilities are located, and sold directly to an end user, the following shall apply:
1. The portion of the pipeline that is downstream of the point at which no additional gas enters the pipeline from a production facility or, in cases involving a single production facility, that is downstream of the point at which the pipeline enters a public right-of-way, or adjacent private right-of-way, is a transmission line if it operates at a hoop stress of 20 percent or more of SMYS or, otherwise, a distribution line. Such transmission or distribution lines shall fully comply with the applicable requirements contained in this Part for such
(2) In cases where gas is transported directly from production facilities and sold to a single end-user, that portion of the pipeline which is downstream of the end-user's property line is a service line and shall comply with the applicable requirements contained in this Part.

(3) Any person who intends to transport and sell gas from a production facility directly to an end-user shall report such intent as part of the notification required by subdivision (c) of this section.

(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 of this Part.

(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.

(1) All joints shall be visually inspected for defects and shall have a neat workmanlike appearance. Qualified welders and plastic joiners shall be employed.

(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 (2) of this subdivision, 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, disk, 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.

*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.

(4) Each gathering line must be protected from washouts, floods, unstable soil, landslides or other hazards that may cause the pipeline
to be exposed, to move, or to sustain abnormal loads.

(5) A suitable conductive wire shall be installed with plastic pipe to facilitate locating it with an electronic pipe locator. Other approved suitable material or means may be employed for accomplishing this purpose.

(6) The maximum allowable operating pressure for plastic pipelines is to be determined in accordance with either of the formulas in section 255.121 of this Part, subject to the limitations of sections 255.123(b) through (d) of this Part.

(7) All deleterious defects, gouges, dents and grooves shall be eliminated prior to testing.

(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.

(9) Test medium shall be air, inert gas or water. Other approved media may be used.

(10) Regardless of installation date, pipeline markers complying with the requirements of section 255.707(d)-(e) of this Part shall be installed at each crossing of a public road, railroad, navigable waterway, and wherever else it is necessary to identify the location of the gathering line to reduce the possibility of damage or interference. In areas used for commercial farm purposes in at least two of the last five years, pipeline markers shall be installed at points which adequately identify the location and direction of the pipeline. Such location points shall be determined in consultation with the farmland operator.

(11) Maps shall be prepared documenting the location of the line and critical valves.

(12) The pipelines shall be patrolled a minimum of every two years for washouts and other hazardous conditions, including a check for area population development change.

(13) The line shall be surveyed for leakage at least once every five years.

(14) The adequacy of over pressure protection devices shall be verified annually to ensure safe operation of the line.

(15) To abandon the gathering system in place, all sources of gas must be disconnected from the system, the system shall be purged with air or inert gas and the ends sealed.

(16) Sufficient documentation shall be maintained to demonstrate compliance with these regulations.

255.11 Petroleum gas systems. Each pipeline system subject to this Part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of ANSI/NFPA 58 and 59 (as described in section 10.3 of this Title).

255.13 General.

(a) The rules and regulations of this Part are considered adequate for safety under conditions normally encountered in the gas industry. However, these rules and regulations cannot specifically provide for all abnormal or unusual conditions; nor can they specifically detail all
methods for achieving compliance. Approved alternate methods may be used provided that all work performed within the scope of this Part shall meet or exceed the safety standards expressed or implied herein.

(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 Gas Piping Technology Committee Guide (GPTC) for Gas Transmission and Distribution Piping Systems is, except where in conflict with provisions of this Part, representative of this level of practice.

(c) Waiver. If a waiver of or deviation from the application of any rules prescribed in this Part is indicated because of special facts, application may be made to the Public Service Commission for waiver of or deviation from the rules and regulations in this Part. Each request shall include a full and comprehensive justification for such requested waiver or deviation, together with a proposed alternate rule to be considered for application to the conditions requiring the waiver or deviation.

(d) This Part is concerned with the safety of the general public and employee safety to the extent that it is affected by basic design, quality of the materials and workmanship, requirements for testing, and maintenance of gas transmission and distribution facilities. Existing industrial safety regulations pertaining to work area, safety devices, and safe work practices are not intended to be supplanted by this Part.

255.15 Rules of regulatory construction. (a) As used in this Part:
(1) includes means including but not limited to;
(2) may means is permitted to or is authorized to;
(3) may not means is not permitted to or is not authorized to; and
(4) shall is used in the mandatory and imperative sense.
(b) In this Part:
(1) words indicating the singular include the plural;
(2) words indicating the plural include the singular; and
(3) words indicating the masculine gender include the feminine.

255.17 Preservation of records.
(a) Notwithstanding the requirements of Part 293 or Part 733 of this Title, the minimum period of retention of records required by this Part shall be at least three years. Longer periods of retention may be mandated by Section 255.517 of this Part, Part 293 and Part 733 of this Title.

(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.

(c) All records or copies thereof, shall be kept on file in the State of New York and accessible to the staff of the Department of Public Service.

255.51 Scope. Sections 255.53 through 255.65 of this Part prescribe the minimum requirements for the selection and qualification of pipe and components for use in pipelines.

255.53 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;
(b) chemically compatible with any gas that they transport and with
any other material in the pipe with which they are in contact; and
(c) qualified in accordance with the applicable requirements of this Part.

255.55 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 section II or III of Appendix 14-B of
this Title; or
   (3) it is used in accordance with subdivision (c) 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 14-B of this
Title;
   (2) it meets the requirements of section II or III of Appendix 14-B of
this Title;
   (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 14-B
of this Title; or
   (4) it is used in accordance with subdivision (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 psi (41 MPa) where no close coiling or
close bending is to be done.
(d) New steel pipe that has been cold expanded must comply with the
mandatory provisions of API Specification 5L (as described in Section
10.3 of this Title).

255.57 Cast iron or ductile iron pipe. Cast and ductile iron pipe is
prohibited from use in new or replacement installations.

255.59 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; and
   (2) it is resistant to chemicals with which contact may be
anticipated.
   (b) Acrylonitrile-butadiene-styrene (ABS) thermoplastic material is
prohibited from use in new or replacement installations.
   (c) Used plastic pipe is prohibited from use in new or replacement
installations. This does not prohibit the reactivation of a plastic
pipeline.
   (d) For the purpose of paragraph (a) (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.

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

255.63 Marking of materials.

(a) 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, except that thermoplastic fittings must be marked in accordance with ASTM D 2513 (as described in section 10.3 of this Title); or

(2) MSS Standard Practice, SP-25 (as described in section 10.3 of this Title).

(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.

255.65 Transportation of pipe.

(a) 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 the transportation is performed in accordance with API RP5L1, (as described in section 10.3 of this Title).

(b) Ship or barge. 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 ration of 70 to 1, or more, that is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API Recommended Practice 5LW, (as described in Section 10.3 of this Title).

255.101 Scope.

Sections 255.103 through 255.125 of this Part prescribe the minimum requirements for the design of pipe.

255.103 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.

255.105 Design formula for steel pipe.

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

\[ P = (2 \frac{St}{D}) \times F \times E \times T \]

- \( P \) = 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 of this Part.
- \( D \) = Nominal outside diameter of the pipe in inches (millimeters).
- \( t \) = Nominal wall thickness of the pipe in inches (millimeters).
- \( F \) = Design factor determined in accordance with section 255.111 of this Part.
- \( E \) = Longitudinal joint factor determined in accordance with section 255.113 of this Part.
- \( T \) = Temperature derating factor determined in accordance with section 255.115 of this Part.

(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 900µF (482µC) at any time or is held above 600µF (316µC) for more than one hour.

255.107 Yield strength (S) for steel pipe.

(a) For pipe that is manufactured in accordance with a specification listed in section I of Appendix 14-B of this Title, the yield strength to be used in the design formula in section 255.105 of this Part 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 14-B of this Title and whose specification or tensile properties are unknown, the yield strength to be used in the design formula in section 255.105 of this Part is one of the following:

(1) if the pipe is tensile tested in accordance with section II-D of Appendix 14-B to this Title, the lower of either 80 percent of the average yield strength determined by the tensile tests, or the lowest yield strength determined by the tensile tests; or

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

255.109 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, 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.

255.111 Design factor (F) for steel pipe.

(a) Except as otherwise provided in subdivisions (b), (c) and (d) of this section, the design factor to be used in the design formula in section 255.105 of this Part is determined in accordance with the following table:

<table>
<thead>
<tr>
<th>Class</th>
<th>Location</th>
<th>Design Factor (F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td></td>
<td>0.72</td>
</tr>
<tr>
<td>2</td>
<td></td>
<td>0.60</td>
</tr>
<tr>
<td>3</td>
<td></td>
<td>0.50</td>
</tr>
<tr>
<td>4</td>
<td></td>
<td>0.40</td>
</tr>
</tbody>
</table>

(b) A design factor of 0.60 or less must be used in the design formula in section 255.105 of this Part for steel pipe in Class I locations that:

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

(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 section 255.105 of this Part 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 section 255.105 of this Part
for steel pipe in a compressor station, regulating station, or measuring
station.

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 of this Part is determined in accordance with the
following table:

<table>
<thead>
<tr>
<th>Specification*</th>
<th>Pipe Class</th>
<th>Longitudinal Joint Factor (E)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ASTM A 53/A 53M Seamless</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Furnace butt welded</td>
<td></td>
<td>0.60</td>
</tr>
<tr>
<td>ASTM A 106 Seamless</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Furnace butt welded</td>
<td></td>
<td>0.60</td>
</tr>
<tr>
<td>ASTM A 211 Spiral welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Furnace butt welded</td>
<td></td>
<td>0.60</td>
</tr>
<tr>
<td>ASTM A 333 Seamless</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>ASTM A 381 Double submerged</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>ASTM A 671 Electric fusion</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Furnace butt welded</td>
<td></td>
<td>0.60</td>
</tr>
<tr>
<td>ASTM A 672 Electric fusion</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>ASTM A 691 Electric fusion</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>API 5 L Seamless</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric resistance welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Electric flash welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Submerged arc welded</td>
<td></td>
<td>1.00</td>
</tr>
<tr>
<td>Furnace butt welded</td>
<td></td>
<td>0.60</td>
</tr>
<tr>
<td>Other Pipe over four inches</td>
<td></td>
<td>0.80</td>
</tr>
<tr>
<td>(102 millimeters) or less</td>
<td></td>
<td>0.60</td>
</tr>
</tbody>
</table>

*As described in section 10.3 of this Title.

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

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:

<table>
<thead>
<tr>
<th>Gas Temp. in degrees Fahrenheit (Celsius)</th>
<th>Temperature derating factor (T)</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 (121) or less</td>
<td>1.000</td>
</tr>
<tr>
<td>300 (149)</td>
<td>0.967</td>
</tr>
<tr>
<td>350 (177)</td>
<td>0.933</td>
</tr>
</tbody>
</table>
(b) For intermediate gas temperatures, the derating factor is determined by interpolation.

255.121 Design of plastic pipe.

The design pressure for plastic pipe is determined by either of the following formulas, subject to the limitations of section 255.123 of this Part:

\[
P = \begin{cases} 
2 \times S \times DF \\
(\text{D} - \text{t}) \\
2S \times DF \\
(5\text{DR} - 1) 
\end{cases}
\]

Where:

\[P = \text{Design pressure, psig (kPa)}\]
\[S = \text{For thermoplastic pipe, the HDB determined in accordance with the listed specification at a temperature equal to 73\text{µF (23µC)}, 100\text{µF (38µC), 120\text{µF (49µC), or 140\text{µF (60µC). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part E of PPI TR-3 entitled, Policy for Determining Long-Term Strength (LTHS) by Temperature Interpolation, as published in the technical report TR-3 "HDB/PBD/MRS Policies" (as described in section 10.3 of this Title). For reinforced thermosetting plastic pipe, 11,000 psi (75.8 MPa). (Note: Arithmetic interpolation is not allowed for PA-11 pipe.)}\]
\[t = \text{Specified wall thickness, inches (millimeters).}\]
\[\text{D} = \text{Specified outside diameter, inches (millimeters).}\]
\[\text{SDR} = \text{Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute preferred number series 10.}\]
\[\text{DF} = 0.32 \text{ or } 0.40 \text{ for PA-11 pipe produced after January 23, 2009 with nominal size (IPS or CTS) 4-inch or less, and a SDR of 11 or greater (i.e. thicker pipe wall).}\]

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 (689 kPa).

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

1. below -20\text{µF (29µC), or -40µF (-40µC) if all pipe and pipeline components whose operating temperature will be below -20µF (-29µC) have a temperature rating by the manufacture 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 of this Part is determined, except that thermoplastic pipe manufactured before May 18, 1978, may be used at temperatures up to 100µF (38°C); or
(3) in the case of reinforced thermosetting plastic pipe up to 150µF (66°C).
(c) The wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).
(d) The wall thickness for reinforced thermosetting plastic pipe may not be less than that listed in the following table:

<table>
<thead>
<tr>
<th>Minimum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal diameter</td>
</tr>
<tr>
<td>inches</td>
</tr>
<tr>
<td>(millimeters)</td>
</tr>
<tr>
<td>2 (51)</td>
</tr>
<tr>
<td>3 (76)</td>
</tr>
<tr>
<td>4 (102)</td>
</tr>
<tr>
<td>6 (152)</td>
</tr>
</tbody>
</table>

(e) The design pressure for thermoplastic pipe produced after July 14, 2004, may exceed a gauge pressure of 100 psig (689 kPa) provided that:
(1) the design pressure does not exceed 125 psig (862 kPa);
(2) the material is a PE2406 or a PE3408 as specified within ASTM D2513 (as described in Part 10.3 of this Title);
(3) the pipe size is nominal pipe size (IPS) 12 or less; and
(4) the design pressure is determined in accordance with the design equation defined in section 121 of this Part.
(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.
(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 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.

255.141 Scope.
Sections 255.143 through 255.193 of this Part prescribe the minimum requirements for the design and installation of pipeline components and facilities, other than overpressure protection.

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.

255.144 Qualifying metallic components. Notwithstanding any requirement of this Part which incorporates by reference an edition of a document listed in Section 10.3 or Appendix 14B of this Title, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this Part if:

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

(b) the edition of the document under which the component was manufactured has equal or more stringent requirements than an edition of that document currently or previously incorporated by reference (as described in Section 10.3 or Appendix 14B of this Title) for pressure testing, materials, and pressure and temperature ratings.

255.145 Valves.

(a) Except for cast iron and plastic valves, each valve must meet the minimum requirements, or the equivalent, of API 6D (as described in section 10.3 of this Title). 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 percent 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 percent of the pressure ratings for comparable steel valves; at their listed temperature, if:

(1) the temperature-adjusted service pressure does not exceed 1,000 PSIG (6.9 MPa); 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 shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure rating for comparable steel valves at their listed temperature

(e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.

255.147 Flanges and flange accessories. (a) Each flange or flange accessory must meet the minimum requirements of ANSI B16.5 or MSS SP-44, 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.

(c) Bolts or stud-bolts used shall extend completely through the nuts.

255.149 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-welded fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.

(c) 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.

255.150 Passage of internal inspection devices. (a) Except as provided in subdivision (b) of this section, each new transmission line and each pipe section, valve, fitting or other line component of a transmission line that is replaced must be designed and constructed to accommodate the passage of instrumented internal inspection devices.

(b) This section does not apply to:

(1) manifolds;

(2) station piping such as at compressor stations, meter stations, or regulator stations;

(3) piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;

(4) cross-overs;

(5) sizes of pipe for which an instrumented internal inspection device is not commercially available; and

(6) transmission lines, operated in conjunction with a distribution system, which are installed in Class 4 locations.

255.151 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 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 1 1/4-inch (32 millimeters) tap may be made in a four-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.

(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, Division I (as described in section 10.3 of this Title).

(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 (as described in section 10.3 of this Title), except for:

1. manufactured butt-welded fittings;
2. pipe that has been produced and tested under a specification listed in Appendix 14-B of this Title;
3. partial assemblies such as split rings or collars; or
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 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 Vessel 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.

255.155 Welded branch connections.

(a) 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.

(b) The reinforcement required in a welded branch connection shall be determined by the rule that the metal area available for reinforcement shall be equal to or greater than the required area as defined in Rules For Reinforcement Of Welded Branch Connections and examples 1 and 2 in Appendix 14-G of this Title.

(c) If a reinforcement member is required, and the branch diameter is such that a localized type of reinforcement member would extend around more than half the circumference of the header, then a complete encirclement type of reinforcement member shall be used, regardless of the design hoop stress, or a smoothly contoured wrought steel tee of proven design may be used.

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

255.159 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.
255.161 Supports and anchors.
   (a) Each pipeline and its associated equipment must have enough anchorage or support to:
       (1) prevent undesigned-for 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 support or anchorage 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, non-combustible material and must be designed and installed in compliance with the following:
       (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 percent 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 an 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) 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.

255.163 Compressor stations: design and construction.
   (a) 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 catching on fire from a conflagration at structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of firefighting equipment.
   (b) Each building on a compressor station site must be made of noncombustible materials if it contains either:
       (1) pipe more than two inches (51 millimeters) in diameter that is carrying gas under pressure; or
       (2) gas handling equipment other than gas utilization equipment used for domestic purposes.
   (c) 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.
(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.

(e) Electrical equipment and wiring installed in compressor stations must conform to the National Electric Code, NFPA-70 (as described in section 10.3 of this Title), so far as that code is applicable.

255.165 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) have either automatic liquid removal facilities, an automatic compressor shut-down device, or a high liquid level alarm where slugs of liquid could be carried into the compressors; and
   (3) be manufactured in accordance with section VIII of the ASME Boiler and Pressure Vessel Code (as described in section 10.3 of this Title), except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

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:
   (a) It must be able to block gas out of the station and blow down the station piping.
   (b) It must discharge gas from the blow down piping at a location where the gas will not create a hazard.
   (c) It must provide means for extinguishing gas fires and for the shutdown of gas compressing equipment, and electrical facilities in the vicinity of gas headers and in the compressor building, except that 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 electrical circuits needed to protect equipment from damage may remain energized.
   (d) It must be operable from at least two locations, each of which is:
      (1) outside the gas area of the station;
      (2) near the exit gates, if the station is fenced, or near emergency exits, if not fenced; and
      (3) not more than 500 feet (152.4 meters) from the limits of the station.
   (e) If a compressor station supplies gas directly to a distribution system with no other adequate sources 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.

255.169 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 percent.

(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.

(c) A pressure relief valve shall be installed in the discharge line of each positive-displacement transmission compressor between the gas compressor and the first discharge block valve. The relieving capacity shall be equal to or greater than the capacity of the compressor.

255.171 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.

(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.

(f) All fuel gas lines within a compressor station, serving the various buildings and residential areas, shall be provided with master shut-off valves located outside of any building or residential area.

255.173 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.

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 (.805 kilometer) of a valve.

(2) Each point on the pipeline in a Class 3 location must be within two 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 five 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

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

(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.

(d) Each blow-down discharge must be located so the gas can be blown to the atmosphere without hazard and, if the line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.

255.181 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 as well as the number and type of consumers that might be affected by a shutdown.

(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.

(c) Except for single feed systems, regulator stations reducing the pressure from pounds to pounds must also have an emergency valve installed on the station's outlet piping in compliance with paragraphs (b) (1) and (2) of this section.

(d) Each valve on a main installed for operating or emergency purposes must:

(1) be placed in a readily accessible location so as to facilitate its operation in an emergency;

(2) have an operating stem or mechanism that is readily accessible; and

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

(e) Each station bypass valve or valve that separates systems operating at different pressures must be identified to prevent unauthorized or inadvertent operation, or be equipped with a device designed to prevent unauthorized operation.

255.183 Vaults: structural design requirements.

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating equipment, 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 (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.

(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.

(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 the vault or pit, unless such parts are suitably protected.

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

255.185 Vaults: accessibility. Each vault must be located in an accessible location and, so far as practical, away from:

(a) street intersections or points where traffic is heavy or dense;
(b) points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
(c) water, electric, steam or other facilities.

255.187 Vaults: sealing, venting and ventilation.

(a) Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated.

(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 four inches (102 millimeters) in diameter.

(2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit.

(3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.

(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:

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

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

(3) If the vault or pit is ventilated, subdivision (b) or (d) of this section applies.

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

255.189 Vaults: drainage and waterproofing. (a) Each vault must be designed so as to minimize the entrance of water. Nevertheless, vault equipment shall be designed to operate safely, if submerged.
(b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.

(c) All electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA 70 (as described in section 10.3 of this Title).

255.190 Calorimeter or calorimixer structures. (a) Unmanned structures housing calorimeters or calorimixers shall be designed so that the egress shall be directly to and from the outside, and all air movements shall be directly to and from the outside atmosphere. All associated devices which may vent gas shall be vented through piping to the outside atmosphere.

(b) Unmanned rooms with such gas burning equipment shall be equipped with sensing devices which provide for both the automatic shutdown of the gas supply to such rooms and the signalling of an alarm at a continuously manned post. All alarms shall be immediately investigated.

(c) Combustible material associated with such gas-burning equipment shall be stored safely, and in a manner which separates them from sources of ignition.

255.191 Design pressure of plastic fittings.

(a) Thermosetting fittings for plastic pipe must conform to ASTM D 2517 (as described in section 10.3 of this Title).

(b) Thermoplastic fittings for plastic pipe must conform to ASTM D 2513 (as described in section 10.3 of this Title).

(c) The design pressure of polyvinyl chloride (PVC) Schedules-40 and 80 thermoplastic fittings must be obtained from the following table:

<table>
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<th>Size inches</th>
<th>Schedule 40</th>
<th>PVC Type II Class Location 1 2 &amp; 3 4</th>
<th>PVC Type I Class Location 1 2 &amp; 3 4</th>
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Note: These pressure ratings are the same value as the design pressure of the corresponding pipe size and schedule in the same class location, as determined by the formula given in section 255.121 of this Part and the limitations of section 255.123.

255.193 Valve installation in plastic pipe. Each valve installed in plastic pipe must be designed so as to protect the plastic material against excessive torsional or shearing loads when the valve or shut-off is operated, and from any other secondary stresses that might be exerted through the valve or its enclosure.

255.194 Scope. Sections 255.195 through 255.203 of this Part prescribe the minimum requirements for the design and installation of overpressure protection devices.

255.195 Protection against accidental overpressuring. (a) Except as provided in section 255.197 of this Part, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of sections 255.199 and 255.201 of this Part.

(b) Additionally, each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must:

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

(2) be designed so as to prevent accidental overpressuring.

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

(a) If the maximum actual operating pressure of the distribution system is 60 psig (414 kPa) or less and a service regulator having the following characteristics is used, no other pressure limiting device is required.

(1) The regulator is capable of reducing distribution line pressure to pressures recommended for household appliances.

(2) It has a single port valve with proper orifice for the maximum gas pressure at the regulator inlet.

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

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

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

(6) The regulator is self-contained with no external static or control lines.

(7) The regulator is of a type including a relief valve which is vented to the atmosphere with the relief valve set to open so that the pressure of the gas going to the customer does not exceed the maximum safe pressure as established by this Part.

(b) If the maximum actual operating pressure of the distribution system is 60 psig (414 kPa) or less, and a service regulator is used that does not have all of the characteristics listed in subdivision (a) of this section or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

(c) If the maximum actual operating pressure of the distribution system exceeds 60 psig (414 kPa), unless higher pressure is needed by the customer or it is impractical or unsafe to regulate the pressure outside, one of the following methods must be used to regulate and limit the pressure of gas delivered to the customer.

(1) A service regulator having the characteristics listed in subdivision (a) of this section, and another regulator located upstream from the service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 psig (414 kPa). A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 psig (414 kPa) or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shut-off that closes if the pressure on the inlet of the service regulator exceeds the set pressure (60 psig (414 kPa) or less), and remains closed until manually reset.

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

(3) A service regulator with a relief valve set to open so that the pressure of gas going to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator or it may be a separate unit installed downstream from the service regulator. Either of these combinations may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 psig (862 kPa). For higher inlet pressure, the methods in paragraph (1) or (2) of this subdivision must be used.

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

(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.  
(a) Except for rupture discs, each pressure relief or pressure limiting device must:
(1) be constructed of materials such that the operation of a device will not be impaired by corrosion;
(2) have valves and valve seats that are designed not to stick in a position that will make the device inoperative;
(3) be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;
(4) have its support made of noncombustible material;
(5) have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;
(6) be designed and installed so that the size of the opening, pipe, and fittings located between the system to be protected and the pressure-relieving device, and the size of the vent line, are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;
(7) where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed in compliance with subdivision (b) of this section to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protection device and the district regulator;
(8) except for a valve that will isolate the system under protection from its source of pressure be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure-limiting device inoperative; and
(9) where gas pressures are reduced in two or more stages to supply pipelines except field regulators, be designed and installed in compliance with subdivision (b) of this section so that any single incident in one stage will not adversely affect another stage.
(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 Department.
(c) The requirements contained in subdivision (b) of this section do not apply to those existing stations which, due to their locations or other station protection design features, are adequately protected against any credible single incident affecting the operation of both the overpressure protection device and the district regulator, or which supply integrated distribution systems employing multiple overpressure protection devices of sufficient capacity to prevent overpressuring of the distribution system.
(d) Notwithstanding the installation date or the retroactivity provided by section 255.2(a) of this Part, when overpressure protection is provided by a monitor regulator, a means must be provided to verify that the regulator is functioning properly.
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 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 lesser 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 two PSIG (14 kPa).

255.203 Instrument, control and sampling piping and components.
   (a) This section applies to the design of instrument, control, and sampling piping and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices.
   (b) All materials employed for pipe and components must be designed to meet the particular conditions of service and the following paragraphs:
      (1) Each takeoff connection and attaching boss, fitting, or adapter must be made of material suitable 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) Except for takeoff lines that can be isolated from sources of pressure by other valuing, a shut-off valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blow-down valves must be installed where necessary.
      (3) Brass or copper material may not be used for metal temperatures greater than 400°F (204°C).
      (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 over-pressure protective device inoperative.

255.221 Scope.

(a) Sections 255.225 through 255.245 of this Part prescribe minimum requirements for welding steel materials in pipelines.

(b) These sections do not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

255.225 Qualification of welding procedures.

(a) Welding must be performed by a qualified welder in accordance with welding procedures qualified according to section 5 of API Standard 1104 (as described in section 10.3 of this Title) or section IX of the ASME Boiler and Pressure Vessel Code (as described in section 10.3 of this Title).

(b) The quality of the test welds used to qualify the procedures shall be determined by destructive testing.

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

255.227 Qualification of welders.

(a) Except as provided in subdivision (b) of this section, each welder must be qualified in accordance with section 6 of API Standard 1104 (as described in section 10.3 of this Title) or section IX of the ASME Boiler and Pressure Vessel Code (as described in section 10.3 of this Title). However, a welder qualified under an earlier edition than listed in Section 10.3 of this Title may weld but may not requalify under that earlier edition.

(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 of this Title. A welder who makes welded service line connections to mains must also perform an acceptable test weld under section II of Appendix 14-F of this Title as a part of his qualifying test.

255.229 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 six calendar months, he has engaged in welding with
that process.

(c) A welder qualified under subdivision 255.227(a) of this Part may not weld unless within the preceding six calendar months the welder has had one weld tested and found acceptable under section 6 or 9 of API Standard 1104 (as described in section 10.3 of this Title), except that a welder qualified under an earlier edition than listed in Section 10.3 of this Title may weld but may not requalify under that earlier edition.

(d) A welder qualified under subdivision 255.227(b) of this Part may not weld unless:

1. within the preceding 15 calendar months, the welder has requalified, except that the welder must requalify at least once each calendar year; or
2. within the preceding 7 1/2 calendar months, but at least twice each calendar year, the welder has had:
   i. a production weld cut out, tested and found acceptable in accordance with the qualifying test; or
   ii. a production weld tested and found acceptable under section 6 of API Standard 1104 (as described in section 10.3 of this Title); or
   iii. for welders who work only on service lines two 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 Title.

(e) Welder requalification tests shall be required if there is good cause to question a welder's ability.

255.230 Quality assurance program. (a) Each operator shall conduct an unannounced spot check of each welder's field welds at least once each calendar year to assess the quality of welding. Such spot checks shall include destructive or nondestructive tests of a field weld. Should an unannounced spot check of a welder identify unacceptable welds, a follow-up unannounced spot check shall be conducted within three months or as soon as possible thereafter.

(b) A field weld chosen during the unannounced spot check may be used to maintain the welder's qualification if tested and found acceptable under section 3 or 6 of API Standard 1104 (as described in section 10.3 of this Title) for welders qualified under section 255.227(a) of this Part.

(c) In the case of welders qualified under section 255.227(b) of this Part, the spot check must follow the test procedures set forth in Appendix 14-F of this Title.

(d) This unannounced test may be used to satisfy the requirement to have a weld tested during the six months preceding welding as required in section 255.229(c) or (d) (2) of this Part.

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

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

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12 1/2 degrees 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 percent or less of SMYS may not deflect the
pipe more than 90 degrees.

SO DOC 16B-255.235

NYCRR

255.235 Preparation for welding. (a) 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.

(b) See Appendix 14-J of this Title for acceptable preparation for
butt welding pipe of unequal thicknesses.

SO DOC 16B-255.237

NYCRR

255.237 Preheating. (a) Carbon steel that has a carbon content in
excess of 0.32 percent (heat analysis) or a carbon equivalent (C + 1/4
Mn) of 0.65 percent (heat analysis) must be preheated for welding.

(b) Carbon steel that has a lower carbon content or carbon equivalent
than the steels covered by subdivision (a) of this section must be
preheated for welding when preheating 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) Preheating may be accomplished by any suitable method, provided
that it is uniform and that the temperature does not fall below the
prescribed minimum during the actual welding operation.

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

SO DOC 16B-255.239

NYCRR

255.239 Stress relieving.

(a) Except as provided in subdivision (f) of this section, each weld
on carbon steel that has a carbon content in excess of 0.32 percent
(heat analysis) or a carbon equivalent (C + 1/4 Mn) in excess of 0.65
percent (heat analysis) must be stress relieved as prescribed in section
VIII of the ASME Boiler and Pressure Vessel Code (as described in
section 10.3 of this Title).

(b) Except as provided in subdivision (f) of this section, each weld
on carbon steel that has a carbon content of less than 0.32 percent
(heat analysis) or a carbon equivalent (C + 1/4 Mn) of less than 0.65
percent (heat analysis) must be thermally stress relieved when
conditions exist that would cause the weld to cool at a rate detrimental
to the quality of the weld.

(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.

(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 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 two 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 1,100 °F (593 °C) for carbon steels and at least 1,200 °F (649 °C) for ferritic alloy steels.

(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.

255.241 Inspection and test of welds.

(a) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that the welding is performed in accordance with the welding procedure and the weld is acceptable under subdivision (c) of this section.

(b) The butt welds on each pipeline with a nominal diameter greater than two inches (51 millimeters) to be operated at 125 PSIG (862 kPa) or more must be nondestructively tested in accordance with section 255.243 of this Part.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 of API Standard 1104 (as described in section 10.3 of this Title). However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix A to API Standard 1104 applies to the weld, the acceptability of that weld may be further determined under that Appendix.

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

(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 in accordance with written procedures and 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 section 255.241(c) of this Part.

(d) 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, at least 10 percent;
2. in Class 2 locations, at least 15 percent;
3. in Class 3 and Class 4 locations, 100 percent;
4. in Class 1 or 2 locations at crossings of major or navigable rivers, at crossings of major roads, and within railroad or public
highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent; and

(5) at pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

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

(f) 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 nondestructively tested, the number rejected, and the disposition of the rejects.

NYCRR 255.244 Welding inspector.

(a) No person may carry out the inspection of joints in welded pipelines required by sections 255.241 and 255.243 of this Part unless that person has been qualified by appropriate training or experience in evaluating the acceptability of welded joints per the requirements of section 6, Standards of Acceptability, of API Standard 1104 (as described in section 10.3 of this Title).

(b) Each gas corporation shall establish, and keep on file for inspection, the methods it uses to verify the qualifications of each technician responsible for the interpretation of each nondestructive test of a weld.

(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 of this Part.

NYCRR 255.245 Repair or removal of defects.

(a) Each weld that is unacceptable under section 255.241 (c) must be removed or repaired. A weld must be removed if it has a crack that:

(1) is more than eight percent of the weld length or two inches (51 millimeters) in length whichever is less; or

(2) penetrates either the root or second bead.

(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 Standard 1104 (as described in section 10.3 of this Title).

(c) If the repair is not acceptable, the weld must be removed.

NYCRR 255.271 Scope.

(a) Sections 255.273 through 255.287 of this Part prescribe minimum requirements for joining materials in pipelines, other than by welding.

(b) These sections do not apply to joining during the manufacture of pipe or pipeline components.

NYCRR 255.273 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 proved by test or experience to produce strong gas-tight joints.
(c) Each joint must be inspected to ensure compliance with this Part.

255.279 Copper pipe. (a) Copper pipe may not be butt welded or 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.
(b) The filler material used for brazing shall be a copper-phosphorous or silver base alloy.

255.281 Plastic pipe. (a) A plastic pipe joint that is joined by solvent cement, adhesive or heat fusion may not be disturbed until it has properly set.
(b) Plastic pipe may not be joined by a threaded joint or miter joint.
(c) The quality of the joints shall be checked visually. If there is any reason to believe the joint is defective, it shall be removed and replaced.
(d) Each solvent cement joint on plastic pipe must comply with the following criteria:
(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 D2513 (as described in section 10.3 of this Title).
(3) The safety requirements of Appendix A of ASTM Specification D2513 (as described in section 10.3 of this Title) must be met.
(4) The joint may not be heated to accelerate the setting of the cement.
(e) Each heat-fusion joint on plastic pipe must comply with the following criteria:
(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 piping 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) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of section 255.283(a) (1) (iii) of this Part, to be at least equivalent to those of the fitting manufacturer.
(4) Heat may not be applied with a torch or other open flame.
(f) Each adhesive joint on plastic pipe must comply with the following criteria:
(1) The adhesive must conform to ASTM Specification D2517 (as described in section 10.3 of this Title).
(2) The materials and adhesive must be compatible with each other.
(g) Each compression type mechanical joint on plastic pipe must comply with the following criteria:
(1) The gasket material in the coupling must be compatible with the plastic.
A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

255.283 Plastic pipe: qualifying joining procedures.

(a) Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under section 255.273(b) of this Part is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints, made according to the procedure, to the following tests:

1. The burst test requirements of:
   (i) in the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM Specification D2513 (as described in section 10.3 of this Title); or
   (ii) in the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM Specification D2517 (as described in section 10.3 of this Title).
   (iii) in the case of electrofusion fittings for polyethylene pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM Specification F1055 (as described in section 10.3 of this Title).

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

3. For procedures intended for nonlateral pipe connections, follow the tensile test requirements of ASTM Specification D638 (as described in section 10.3 of this Title), except that the test may be conducted at ambient temperature and humidity. If the specimen elongates no less than 25 percent or failure initiates outside the joint area, the procedure qualifies for use.

(b) Before any written procedure established under section 255.273(b) of this Part is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting five specimen joints made according to the procedure to the following tensile test criteria:

1. Use an apparatus for the test as specified in ASTM Specification D638 (as described in section 10.3 of this Title) (except for conditioning).

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

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

4. Pipe specimens less than four inches (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 four inches (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 100µF (38µC) 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.

(6) Each specimen that fails at the grips must be retested using new pipe.

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

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

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

255.285 Plastic pipe: qualifying persons to make joints. (a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by:

(1) appropriate training or experience in the use of the procedure; and

(2) making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in subdivisions (b) and (c) of this section.

(b) The specimen joint must be visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure.

(c) Additionally, in the case of a heat fusion, solvent cement, or adhesive joint, the joint must be:

(1) tested under any one of the test methods listed under section 255.283(a) of this Part applicable to the type of joint and material being tested; or

(2) examined by ultrasonic inspection and found not to contain flaws that would cause failure; or

(3) cut into at least three longitudinal straps, each of which is visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area and deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(d) A person must be requalified under an applicable procedure if during any 12 month period that person:

(1) does not make any joints under that procedure; or

(2) has three joints or three percent of the joints made under that procedure, whichever, is greater, that are found unacceptable by testing under section 255.507 or 255.511 of this Part, by inspection by other than the joiner, or a combination of both.

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

255.287 Plastic pipe: inspection of joints. No person may carry out the inspection of joints in plastic pipes required by sections 255.273 (c) and 255.285 (b) of this Part unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.
255.301 Scope.
Sections 255.302 through 255.327 of this Part prescribe minimum requirements for constructing transmission lines and mains.

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 of this Title. The letter of intent need not include said specifications where the length of the line is less than the following:

<table>
<thead>
<tr>
<th>Class location</th>
<th>Length</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class 1</td>
<td>1,000 feet (304.8 meters)</td>
</tr>
<tr>
<td>Class 2</td>
<td>500 feet (152.4 meters)</td>
</tr>
<tr>
<td>Class 3</td>
<td>250 feet (76.2 meters)</td>
</tr>
<tr>
<td>Class 4</td>
<td>100 feet (30.5 meters)</td>
</tr>
</tbody>
</table>

(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 Department. The construction standards shall cover all phases of the work and shall be in sufficient detail to cover the requirements of this Part.

255.305 Inspection: general.
(a) Each transmission line and main must be inspected during construction to ensure that it is constructed in accordance with this Part.
(b) Inspections shall be made at sufficiently frequent intervals to assure the required quality of workmanship.
(c) Inspectors shall be qualified by either experience or training and shall have the authority to order the repair or removal and replacement of any component that fails to meet the standards of this Part.
(d) The operator shall maintain a current list of designated inspectors.

255.307 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. These inspections must be made:
(a) prior to the coating operation for field coated pipe; and
(b) as the pipe is lowered into the ditch.

255.309 Repair of steel pipe.
(a) Each imperfection or damage that impairs the serviceability of the length of steel pipe must be repaired or removed.
(b) 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 pressure of the pipeline.

(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:

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

(2) a dent that affects a longitudinal weld or a circumferential weld;

(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 two percent of the nominal pipe diameter in pipe over 12 3/4 inches (324 millimeters) in outer diameter.

(d) 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.

(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.

(f) Complete removal of the metallurgical notch created by an arc burn can be determined by grinding away the visible evidence of the arc burn and then swabbing the ground area with a 20 percent solution of ammonium persulfate. A blackened spot is evidence of a metallurgical notch and indicates that additional grinding is necessary.

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

(h) 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.

(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.

(a) Each field bend in steel pipe must comply with the following criteria:

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

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

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

(1) the bend is made with an internal bending mandrel; or

(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 two inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least one inch (125 millimeters).

NYCRR 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.

NYCRR 255.317 Protection from hazards. (a) When pipelines must be installed where they will be subjected to natural hazards, such as washouts, floods, unstable soil, landslides, or other conditions which may cause serious movement of, or abnormal loads on the pipeline, reasonable precaution shall be taken to protect the pipeline, such as increasing the wall thickness, constructing revetments, preventing erosion, installing anchors, etc.

(b) Where pipelines cross areas which are normally underwater or subject to flooding (i.e., lakes, bays, swamps), sufficient weight or anchorage shall be applied to the line to prevent flotation.

(c) Because submarine river crossings may be subject to washouts due to the natural hazards of stream bed changes, high water velocities, deepening of the channel, or changing of the channel location in the stream bed, design attention shall be given to protect the pipeline at such crossings. The crossing shall be located in stable bank and bed locations. The depth of the line, location of the bends in the banks, wall thickness of the pipe, weighting of the line shall be selected based on the characteristics of the river.

(d) Where pipelines are exposed, such as at spans, trestles, and bridge crossings, the pipelines and mains shall be reasonably protected by distance or barricades from accidental damage by vehicular traffic or other causes.

NYCRR 255.319 Installation of pipe in a ditch. (a) When installed in a ditch, each transmission line and main must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.

(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 coating from equipment or from the backfill material.

NYCRR 255.321 Installation of plastic pipe.
(a) Plastic pipe must be installed below ground level unless otherwise permitted by subdivisions (1) and (m) of this section.

(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 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch (1.58 millimeters).
(e) Plastic pipe that is not encased must have an electrically conductive wire or other approved means of locating the pipe. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

(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. The casing must be prepared to the extent necessary to remove sharp edges, projections, or abrasive material which could damage the plastic.

(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.

(h) 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.

(i) Squeeze-offs of plastic may be made to control flows in accordance with manufacturer's recommendations and a proven procedure without replacement of the pipe section. However, each squeeze-off must be adequately marked on the pipe to preclude further squeeze-off at that location.

(j) The piping shall be installed with sufficient slack to provide for possible contraction. Cooling may be necessary before the last connection is made under extremely high temperature conditions.

(k) That portion of the plastic piping exposed due to the removal of a section of the casing or which spans disturbed earth shall be of sufficient strength to withstand the external loading and shearing forces or it shall be protected with a suitable bridging piece.

(l) Uncased plastic pipe may be temporarily installed above ground level under the following conditions:

1. The operator must be able to demonstrate that the cumulative above ground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.
2. The pipe is located where damage by external forces is unlikely or is otherwise protected against such damage.
3. The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(m) Plastic pipe may be installed on bridges provided that it is:
1. installed with protection from mechanical damage, such as installation in a metallic casing;
2. protected from ultraviolet radiation; and
3. not allowed to exceed the pipe temperature limits specified in section 123 of this Part.

NYCRR 255.323 Casing. (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 percent 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.

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 two 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 six 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 two inches (51 millimeters), provided the main is suitably protected from damage that might result from the proximity of the other structure.

(c) In addition to meeting the requirements of subdivisions (a) and (b) of this section, each plastic pipeline 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.

255.327 Cover.

(a) Except as provided in subdivisions (d), (e) and (f) of this section, each buried transmission line, or distribution main operating at 125 psig (862 kPa) or more in a Class 3 or 4 location, must be installed with a minimum cover as follows:

<table>
<thead>
<tr>
<th>Location</th>
<th>Normal Soil</th>
<th>Normal Rock</th>
<th>Consolidated Soil</th>
<th>Consolidated Rock</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class 1 locations</td>
<td>30 (762)</td>
<td>18 (457)</td>
<td>36 (914)</td>
<td>24 (610)</td>
</tr>
<tr>
<td>Class 2, 3, and 4 locations</td>
<td>36 (914)</td>
<td>24 (610)</td>
<td>36 (914)</td>
<td>24 (610)</td>
</tr>
<tr>
<td>Drainage ditches of public roads and railroad crossings</td>
<td>36 (914)</td>
<td>24 (610)</td>
<td>36 (914)</td>
<td>24 (610)</td>
</tr>
</tbody>
</table>

(b) Except as provided in subdivisions (c), (d), (e) and (f) of this section, each buried distribution main, other than those specified in subdivision (a) of this section, must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where a new distribution main is being inserted into an existing pipeline, the minimum depth of cover may be 18 inches (457 millimeters) provided openings are properly bridged to provide protection from shearing action and external damage.

(d) 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.

(e) All pipe which is installed in areas actively cultivated for commercial farm purposes in at least two out of the last five years, as identified by the farmland operator, shall be installed with a minimum cover of 40 inches (1,016 millimeters) unless the farmland operator agrees to or requires a different depth.

(f) All pipe which is installed in a navigable river, stream, or harbor must have a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by
recognized and generally accepted practices). However, less than the minimum cover is permitted in accordance with subdivision (d) of this section.

255.353 Customer meters and regulators: location.
(a) Each meter and service regulator must be installed in a readily accessible location and be protected from corrosion and other damage, including any vehicular damage that may be anticipated.
(b) Each service regulator on new and replacement service lines, except for replacements by insertion, must be installed outside of the building, unless it is impractical or unsafe. Where the service regulator must be installed within the building, it is to be located as near as practical to the point of service line entrance. For service line replacements where the service regulator must remain inside, the regulator shall be tested and inspected in accordance with section 255.744(d) and (e) of this Part.
(c) The upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.
(d) Each meter installed within a building must be located in a ventilated place and not less than three feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.
(e) When installing a new gas service for which gas pressure regulating and associated gas cleaning equipment and appurtenances is required for a building of public assembly, or apartment building, or building within an apartment, industrial or commercial complex, each with a capacity for normal occupancy of 75 or more persons, the following requirements shall be met:
   (1) When outside installation is impracticable, regulations applicable to indoor installations with high pressure services shall pertain.
   (2) The associated gas cleaning equipment and appurtenances may be located in the same area as the metering and/or pressure regulation equipment.
   (3) Where practicable, the regulating and gas cleaning equipment shall be installed within a separate room that is designed for two-hour fire resistance, and is effectively sealed off from the remaining space in the building.
   (4) In the case of indoor installations, special effort shall be made to prevent and indicate tampering by unauthorized persons.
   (5) In all the above installations and on doors or accesses leading to all the above installations, a conspicuous notice shall be posted indicating the instructions for actions to be taken and the telephone number of the proper person to be called in the event a gas odor is detected.

255.355 Customer meters and regulators: protection from damage.
(a) If the customer's equipment or supplemental gas supply might create either a vacuum or a back pressure, a device must be installed to protect the distribution system. Commingling of a customer's
supplemental gas supply with utility supplied gas is permissible provided the customer verifies that the supplemental gas is interchangeable with the gas supplied by the utility.

(b) The outside terminal of each service regulator vent and relief vent must:
   (1) be rain and insect resistant;
   (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
   (3) be protected from damage caused by submergence in areas where flooding or ice accumulation may occur.

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

255.357 Customer meters and service regulators: installation.
(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.
(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this Part.
(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.
(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

255.359 Customer meter installations: operating pressure.
(a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure.
(b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 PSIG (69 kPa).
(c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.

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.
(b) Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.
(c) Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.
(d) Each service line must be installed so as to minimize anticipated piping strain and external loading.
(e) Each underground service line installed below grade through the outer foundation wall of a building must:
   (1) be encased in a rigid sleeve with suitable protection from shearing action or backfill settlement;
(2) in the case of a metal service line, be protected against corrosion; and
(3) be sealed at the foundation wall to prevent leakage into the building.

(f) When an underground service line is installed under a building, the following requirements apply:
(1) It must be encased in a gas-tight conduit.
(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building.
(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

(g) All service lines shall be constructed with a clearance of not less than four 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 two inches (51 millimeters) shall be maintained and the pipeline shall be protected from damage that might result from the proximity of the other structure.

(h) When steel or plastic pipe is to be installed as a service line in a bore, care shall be exercised to prevent damage to the coating or pipe during installation.

(i) Locating underground service lines. Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with subdivision (e) of section 321 of this Part.

255.363 Service lines: valve requirements.
(a) Each service line must have a service line valve that meets the applicable requirements of this Part. A valve incorporated in a meter bar that allows the meter to be bypassed may not be used as a service line valve. All such exposed valves must be of tamper proof construction.
(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.
(c) Each service line valve on a high pressure service line, installed aboveground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.
(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.
(a) Each service line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.
(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:
(1) where the regulator is located within the customer's building;
(2) on service lines to buildings of public assembly; or
(3) on service lines two inches (51 millimeters) or greater in diameter.

(c) Each underground service line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service line.

255.367 Service lines: general requirements for connections to main piping. (a) Each service line connection to a main should be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

(b) Each compression-type service line to main connection must:
   (1) be designed and installed to effectively sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and
   (2) if gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system.

255.369 Service lines: connections to cast iron or ductile iron mains. (a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of section 255.273 of this Part.

(b) If a threaded tap is being inserted, the requirements of section 255.151(b) of this Part must also be met.

(c) Service line connections shall not be brazed directly to cast iron or ductile iron mains.

(d) Service lines must meet the electrical isolation requirements of section 255.467(b) of this Part.

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).

255.373 Service lines: cast iron and ductile iron. Cast iron or ductile iron pipe shall not be used for new or replacement service lines.

255.375 Service lines: plastic. (a) Each plastic service line outside a building must be installed below ground level, except that:
   (1) it may be installed in accordance with section 255.321(1) of this Part; and
   (2) It may terminate above ground level and outside the building if:
       (i) the aboveground part of the plastic service line is protected against deterioration and external damage.
       (ii) the plastic service line is not used to support external loads.
   (b) Each plastic service line inside a building must be protected against external damage and must not be exposed.

255.377 Service lines: copper. Each copper service line installed
within a building must be protected against external damage.

255.379 New service lines not in use. Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:
(a) The valve that is closed to prevent the flow of gas to the customer must be of tamper-proof construction and 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.
(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly. The mechanical device or fitting shall be of a type that cannot be removed except by properly authorized employees of the operator.
(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

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 (69 kPa) must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:
   (1) function properly up to the maximum operating pressure at which the valve is rated;
   (2) function properly at all temperatures reasonably expected in the operating environment of the service line;
   (3) at 10 PSIG (69 Kpa) close at, or not more than 50 percent 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 percent 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 feet (0.011 cubic meters) per hour; and
   (4) not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.
(b) An excess flow valve must meet the applicable requirements of this Part regarding materials and design of pipeline components.
(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.
(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.
(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

255.383 Excess flow valve customer installation.
(a) Definitions. As used in this section:
(1) Replaced service line means a 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 report the EFV measures detailed in the annual report required by 49 CFR 191.11.

.10 DOC 16B-255.451
255.451 Scope.
Sections 255.452 through 255.491 of this Part prescribe minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

.10 DOC 16B-255.452
255.452 Applicability to converted pipelines. Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline, which qualifies for use under this Part in accordance with section 255.559 of this Part, must meet the corrosion control requirements specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within one year after the pipeline is readied for service. However, the corrosion control requirements specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment which is replaced, relocated or substantially altered.

.10 DOC 16B-255.453
255.453 General. Each operator shall establish procedures as required by section 255.605(b) of this Part to implement these requirements. 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.

.10 DOC 16B-255.455
255.455 External corrosion control: buried or submerged pipelines installed after July 31, 1971.

(a) Except as provided in subdivisions (b), (c) and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion.

(1) It must have an external protective coating meeting the requirements of section 255.461 of this Part.
(2) It must have a cathodic protection system designed to protect the pipeline in its entirety, installed and placed in operation within one year after completion of construction.

(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 six 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.

(2) 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 subdivision (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 five years beyond installation, corrosion during the five-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of subdivision (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 eight. For lower values of pH aluminum may not be installed unless tests or experience indicate its suitability in the particular environment involved.

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

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

(2) the fitting is designed to prevent leakage caused by localized corrosion pitting.

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:
   (1) bare or ineffectively coated transmission lines;
   (2) bare or coated pipes at compressor, regulator, and measuring stations; or
   (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.

NYCRR 255.459 External corrosion control: examination of buried pipeline when exposed.
Whenever any portion of an existing underground steel facility is exposed by the operator, a galvanic type anode shall be attached to that facility if consistent with good corrosion control practices. 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, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, approved indirect method, or both) to determine whether there is additional corrosion, and remedial action must be taken to the extent required by the applicable subdivisions of sections 255.483, 255.485, 255.487, and 255.489 of this Part.

NYCRR 255.461 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 backfilling, and any damage detrimental to effective corrosion control must be repaired.
(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.
(e) Electrical tests of pipe coating on distribution mains, other than those covered by subdivision (d) of this section, shall be conducted where practical.
(f) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.
(g) If coated pipe is installed by boring, driving or other similar
method, precautions must be taken to minimize damage to the coating
during installation.

255.463 External corrosion control: cathodic protection. (a) Each
cathodic protection system required by this Part must provide a level of
cathodic protection that complies with one or more of the applicable
criteria contained in Appendix 14-D of this Title. If none of these
criteria are 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 be cathodically protected; or
(2) the entire buried or submerged pipeline must be cathodically
protected at a cathodic potential that meets the requirements of
Appendix 14-D of this Title for amphoteric metals.

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

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 of this Part. 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 ensure that it is operating.

(c) Each reverse current switch, each diode, and each interference
bond whose failure would jeopardize structure protection must be
electrically checked for proper performance six times each calendar
year, but at intervals not exceeding 2 1/2 months. Each other
interference bond must be checked at least once each calendar year, but
at 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 sections 255.455(b)-(c)
and 255.457(b) of this Part, each operator must, not less than every 3
years at intervals not exceeding 39 months, reevaluate its unprotected
pipelines and cathodically protect them in accordance with this Part in
areas in which active corrosion is found. The operator must determine
the areas of active corrosion by electrical survey. However, on
distribution lines and where an electrical survey is impractical on
transmission lines, areas of active corrosion may be determined by other
means that include review and analysis of leak repair and inspection
records, corrosion monitoring records, exposed pipe inspection records,
and the pipeline environment.

(f) The operator shall determine the areas of active corrosion by electrical survey, or where electrical survey is impractical, by using the required leakage survey (see section 255.723(b) of this Part) in conjunction with an analysis of the corrosion and leak history records, or by other approved means.

NYCRR 255.467 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) One or more insulating devices 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 a ferrous pipe, each pipeline must be either electrically isolated from any metallic casing that is part of the underground system or, if isolation is not achieved because it is impractical, must be treated by other measures 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.

(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 Independent System Operator for the electric facility shall be used in determining the magnitude of such step-and-touch voltages.

(1) Step voltage means the root mean square voltage difference between any two points on the ground surface separated by one meter (approximately the distance of one step) in the direction of the maximum voltage gradient.

(2) Touch voltage means the root mean square voltage difference between any point on the ground where a person may stand and any point on the pipeline or its appurtenances which can be touched simultaneously by either hand.

NYCRR 255.469 External corrosion control: test stations. Each pipeline under
cathodic protection required by this Part must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection.

255.471 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.

255.473 External corrosion control: interference currents.
   (a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize 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.

255.475 Internal corrosion control: general.
   (a) 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, the following requirements apply:
      (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 requirements of section 255.485, 255.487 or 255.489 of this Part.
      (3) Steps must be taken to minimize the internal corrosion.

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

(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.

255.477 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. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but at intervals not exceeding 7 1/2 months.

255.479 Atmospheric corrosion control: general.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under subdivision (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that a corrosive atmosphere does not exist.

255.481 Atmospheric corrosion control: monitoring.

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

<table>
<thead>
<tr>
<th>Location</th>
<th>Frequency of Inspection</th>
</tr>
</thead>
<tbody>
<tr>
<td>Onshore</td>
<td>At least once every 3 calendar years, but with intervals not exceeding 39 months</td>
</tr>
<tr>
<td>Offshore</td>
<td>At least once each calendar year, but with intervals not exceeding 15 months</td>
</tr>
</tbody>
</table>

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by section 479 of this Part.

255.483 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 section 255.461 of this Part.

(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 Part.

(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 Part.

(d) Whenever the annual electrical testing required by section 255.465(a) of this Part reveals that the pipeline or segment of pipeline does not meet the cathodic protection criteria required by section 255.463 of this Part, the operator must complete action to reestablish cathodic protection to the required level prior to the next annual testing or within one calendar year.

(e) When an area of active corrosion is identified, the operator shall provide cathodic protection to the level required by section 255.463 of this Part within one calendar year or replace the section of pipeline within two calendar years.

255.485 Remedial measures: transmission lines.

(a) Each segment of transmission line 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 strength of the pipe based on actual remaining wall thickness. However, if the area of general corrosion is small, the corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion.

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

(c) Under subdivisions (a) and (b) of this section, the strength of transmission line pipe based on actual remaining wall thickness may be determined by the procedure in ASME B31G (as described in section 10.3 of this Title), or other approved procedures, applicable to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

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

(a) Except for cast iron or ductile iron pipe, each segment of a generally corroded pipeline 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 by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered
general corrosion.

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

. SO DOC 16B-255.489

255.489 Remedial measures: cast iron and ductile iron pipelines. (a)
Each segment of cast iron or ductile iron pipe on which general
graphitization is found to a degree where a fracture or any leakage
might result, must be replaced.

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

. SO DOC 16B-255.490

255.490 Direct assessment.

Each operator that uses direct assessment as defined in section
255.903 of this Part on an onshore transmission line made primarily of
steel or iron to evaluate the effects of a threat in the first column
must carry out the direct assessment according to the standard listed in
the second column. These standards do not apply to methods associated
with direct assessment, such as close interval surveys, voltage gradient
surveys, or examination of exposed pipelines, when used separately from
the direct assessment process.

<table>
<thead>
<tr>
<th>Threat</th>
<th>Standard</th>
</tr>
</thead>
<tbody>
<tr>
<td>External corrosion</td>
<td>255.925</td>
</tr>
<tr>
<td>Internal corrosion in pipelines that transport dry gas</td>
<td>255.927</td>
</tr>
<tr>
<td>Stress corrosion cracking</td>
<td>255.929</td>
</tr>
</tbody>
</table>

(a) For lines not subject to the Pipeline Integrity Management
requirements of this Part, the terms "covered segment" and "covered
pipeline segment" in sections 255.925, 255.927, and 255.929 of this Part
refer to the pipeline segment on which direct assessment is performed.

(b) In section 255.925(b) of this Part, the provision regarding
detection of coating damage applies only to pipelines subject to the
Pipeline Integrity Management requirements of this Part.

. SO DOC 16B-255.491

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

(b) Each of the following records must be retained for the period
indicated:

(1) Each record or map required by subdivision (a) of this section,
and each record related to sections 255.465(a), 255.465(e), and
255.475(b), and must be retained for as long as the pipeline remains in
service.

(2) Records of each test, survey, or inspection required by this Part,
in sufficient detail to demonstrate the adequacy of corrosion control
measures or that a corrosive condition does not exist must be retained
for at least 5 years.

. SO DOC 16B-255.501

255.501 Scope.

Sections 255.503 through 255.517 of this Part prescribe minimum
leak-test and strength-test requirements for pipelines.

255.503 General requirements. (a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been reconstructed, relocated, replaced, or reactivated until it has been tested in accordance with this Part to substantiate the proposed maximum allowable operating pressure and each leak has been located and eliminated.

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

1. compatible with the material of which the pipeline is constructed;
2. relatively free of sedimentary materials; and
3. except for natural gas, nonflammable.

(c) If air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

<table>
<thead>
<tr>
<th>Class Location</th>
<th>Natural gas</th>
<th>Air or inert gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>1..................</td>
<td>80</td>
<td>80</td>
</tr>
<tr>
<td>2..................</td>
<td>30</td>
<td>75</td>
</tr>
<tr>
<td>3..................</td>
<td>30</td>
<td>50</td>
</tr>
<tr>
<td>4..................</td>
<td>30</td>
<td>40</td>
</tr>
</tbody>
</table>

(d) Each weld used to tie-in a test segment of pipeline is excepted from the test requirements of this Part.

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.

(b) The test pressure shall be at least equal to 90 percent of SMYS or 1.5 times the maximum allowable operating pressure whichever is less.

(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 Department to use air or inert gas as the test medium.

(d) Except as provided in subdivisions (f) and (g) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 12 hours after stabilization.

(e) A calibrated recording pressure gauge that will indicate increments of five 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.

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

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

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

(3) the component carries a pressure rating established through applicable ASME/ANSI, MSS specifications, or by unit strength calculations as described in section 143 of this Part.

(g) For a short length of pipeline which has not been backfilled and where, throughout its entire length, its entire circumference can be readily examined visually for the detection of leakage, the duration of the test may be reduced to four hours following stabilization.

(h) At least five business days prior to starting the test, the operator shall make notification. In order to maintain continuity of service during emergencies, shorter notice is permissible.

(i) Tests under this section are not considered as satisfactorily accomplished unless certified by an inspector of the 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 three 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 µF (38 µC), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

(c) The test medium shall be water, inert gas or air.

(d) Except as provided in subdivision (f) of this section, the test must be conducted by maintaining the pressure at or above the test pressure for at least one hour after stabilization.

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

(f) For plastic insertions of less than 1,500 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)-(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
(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 three times the design pressure for the pipe.

(e) The test medium shall be water, inert gas or air.

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

(g) The limits of the test shall be from the main to one of the following points:
   (1) in the case of an inside meter or meter-regulator setting, the first fitting inside the wall of the customer's structure through which the service enters;
   (2) in the case of an outside meter or meter-regulator setting, to the meter riser valve, if any, or the first fitting on the riser upstream of the regulator where one is installed; or
   (3) in the case of an inside meter with an outside regulator, to the first fitting on the riser upstream of the regulator.

(h) The service line connection to the main need not be included in these tests if it is not feasible to be so. However, it must be given a leakage test at operating pressure when placed in service.

(i) The test indicator for service line tests shall be a calibrated pressure gauge marked in five 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 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 ensure that the test medium is disposed of in a manner that will minimize damage to the environment.

255.517 Records.
   (a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under sections 255.505 and 255.507 of this Part.

   The record must contain at least the following information:
   (1) the operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used;
   (2) test medium used;
   (3) test pressure;
   (4) test duration;
   (5) pressure record charts;
elevation variations, whenever significant for the particular test; and
(7) leaks and failures noted and their disposition.
(b) Each operator must maintain a record of each test required by section 255.511 of this Part for at least 5 years.

255.551 Scope.
Sections 255.552 through 255.557 of this Part prescribe minimum requirements for qualifying a pipeline for an increased maximum allowable operating pressure.

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 (a) of this section. 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 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 six PSIG (41.4 kPa).
(2) If the maximum allowable operating pressure is between 60 PSIG (414 kPa) and 124 PSIG (855 kPa), notice is required for an increase in pressure greater than 10 percent 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).
255.553 General requirements.
   (a) The pressure must be increased gradually, at a rate that can be controlled.
   (b) Prior to the first pressure increase and at the end of each incremental increase, the pressure must be held constant while the entire segment of the pipeline that is affected is leakage surveyed.
   (c) Each hazardous leak detected must be repaired before a further pressure increase is made. All leaks must be repaired as soon as possible following completion of the upgrading.
   (d) Each operator who upgrades a segment of pipeline shall retain for the life of the segment a record of each investigation required by this Part, of all work performed, and of each pressure test conducted, in connection with the upgrading.
   (e) Each operator who upgrades a segment of pipeline shall establish a written procedure that will ensure compliance with each applicable requirement of this Part.
   (f) Except as provided in section 255.555(c) of this Part, the new maximum allowable operating pressure may not exceed the maximum that would be allowed under sections 255.619 and 255.621 of this Part for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (section 255.105 of this Part) is unknown, the MAOP may be increased as provided in subparagraph 255.619(a)(1) of this Part.

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:
      (1) Review the design, operating, and maintenance history, and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this Part.
      (2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.
      (3) Verify the condition of the pipe through the use of test excavations.
      (4) Either prove compliance with the nondestructive testing requirements of sections 255.241(b) and 255.243(d) of this Part for the current class location or nondestructively test a sufficient number of welds to achieve compliance with the minimum percentages listed in section 255.243(d) of this Part for the current class location.
      (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.
      (6) Establish adequate cathodic protection in compliance with section 255.463 of this Part.
   (c) After complying with subdivision (b) of this section, an operator
may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970 to the highest pressure that is permitted under section 255.619 of this Part, using as a test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).

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

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

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

   (i) it is impractical to test it in accordance with the requirements of this Part;

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

   (iii) the operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this Part.

(e) Where a segment of pipeline is upgraded in accordance with subdivision (c) or paragraph (d) (2) of this section, the increase in pressure must be made in increments that are equal to:

   (1) 10 percent of the pressure before the upgrading; or

   (2) 25 percent of the total pressure increase, which ever produces the fewer number of increments.

.90 DOC 16B-255.557
NYCRR
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).

(b) Increasing the maximum allowable operating pressure for cast iron, ductile iron, and wrought iron pipeline segments is prohibited without prior approval.

(c) Before increasing the operating pressure above the previously established maximum allowable operating pressure, the operator shall comply with the following requirements:

   (1) review the design, operating and maintenance history of the segment of pipeline;

   (2) make a leakage survey (if it has been more than one year since the last survey) and repair any leaks that are found;

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

   (4) for effectively coated steel systems, establish adequate cathodic protection in compliance with section 255.463 of this Part;

   (5) for ineffectively coated or bare steel systems, perform a review for active corrosion, isolate and cathodically protect all coated segments and all services, and where active corrosion exists establish adequate cathodic protection in compliance with section 255.463 of this Part;

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

(7) isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and

(8) if the pressure in mains or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator of adequate capacity on each service line and test each new or existing service regulator to verify that it is functioning properly and adequately vented in compliance with sections 255.355(b) and 255.744(e) of this Part. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.

(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.

255.559 Conversion to service subject to this Part. (a) A steel pipeline previously used in other than natural gas service qualifies for use under this Part if the operator prepares and follows a written procedure to carry out the following requirements:

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

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

(3) All known unsafe defects and conditions must be corrected in accordance with this Part.

(4) The pipeline must be tested in accordance with sections 255.503 through 255.517 of this Part to substantiate the maximum allowable operating pressure permitted by this Part.

(b) Each operator must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of subdivision (a) of this section.

255.601 Scope.

Sections 255.603 through 255.629 of this Part prescribe minimum requirements for the operation of pipeline facilities.

255.603 General provisions. (a) No person may operate a segment of pipeline unless it is operated in accordance with this Part.

(b) Each operator shall prepare and file a detailed written operating and maintenance plan for complying with all the provisions of this Part before operations of a pipeline system commence; it must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. Appropriate parts of the plan must be
kept at locations where operations and maintenance activities are conducted. Revisions to these written procedures shall be submitted at least 30 days prior to the effective date. Minor revisions that do not affect the intent of the procedure may be implemented immediately and submitted on a quarterly basis.

(c) Each operator shall establish and maintain the maps of its transmission lines and distribution mains and maps or records of its service lines as necessary to administer its operating and maintenance plan.

(d) Each operator shall satisfactorily conform with the submitted.

(e) The Commission may require an operator to amend its operating and maintenance plan as necessary to provide a reasonable level of safety.

SOC DOC 16B-255.604
NYCRR
255.604 Operator qualification.

This section prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

(a) Each operator shall have and follow a written qualification program. The program shall include provisions to:

1. Identify covered tasks;
2. Ensure through evaluation that individuals performing covered tasks are qualified;
3. Allow individuals that are not qualified pursuant to this section to perform a covered task if directed and observed by an individual that is qualified;
4. Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident requiring the submission of a report pursuant to 255.801(d) or is otherwise significant in the judgement of the operator;
5. Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;
6. Communicate changes that affect covered tasks to individuals performing those tasks;
7. Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed;
8. After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operations of pipeline facilities; and
9. After December 16, 2004, provide notification if the operator significantly modifies the program.

(b) Each operator shall maintain records that demonstrate compliance with this section.

1. Qualification records shall include:
   1. Identification of qualified individual(s);
   2. Identification of the covered tasks the individual is qualified to perform;
   3. Date(s) of current qualifications; and
   4. Qualification method(s).
2. Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.
3. Operators shall have a written qualification program by April 27,
(d) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(e) Work performance history may be used as a sole evaluation method for individuals who were performing a covered task prior to August 27, 1999.

(f) After October 28, 2002, work performance history may not be used as a sole evaluation method.

(g) After December 16, 2004, observation of on-the-job performance may not be used as the sole method of evaluation.

255.605 Essentials of operating and maintenance plan.

Each operator shall include, as a minimum, the following in its operating and maintenance plan as applicable:

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

(b) procedures required to be included by the provisions of the welding, joining, corrosion control, upgrading, operations, maintenance, and accidents and leaks sections of this Part;

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

(d) provision for periodic inspections to ensure that operating pressures are appropriate for the class location;

(e) precautions to be taken when excavation is performed in the vicinity of any underground gas facility;

(f) procedures to correct, within specified time frames, deficiencies found during any inspections, evaluations, reviews, etc. required by this Part;

(g) criteria employed to determine business districts for the purpose of compliance with section 255.723(b)(1) of this Part;

(h) criteria employed to identify those conditions at leak hazard locations which necessitate that the interval between surveillances be shortened; and

(i) details of how an operator plans to comply with any requirement of this Part that is written in nonspecific language. For example, section 255.805(b) of this Part states that "Each operator shall... establish a means by which it determines the appropriate surveillance interval at leak locations under frost conditions..." the details required by this subdivision would necessitate the operator to specify the established means.

(j) instructions enabling personnel who perform operation and maintenance activities to recognize conditions that may be safety-related conditions that are subject to the reporting requirements of section 255.831 of this Part.

(k) Procedures for making construction records, maps, and operating history available to appropriate personnel;

(l) Procedures for start up and shut down of any section of pipeline in a manner designed to assure operation within the maximum allowable operating pressure limits prescribed by this Part, plus the build-up allowed for operation of pressure limiting and control devices;

(m) Procedures for maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service;
(n) Procedures for starting, operating, and shutting down gas compressor units;

(o) Procedures for periodic review of the work done by operator personnel to determine the effectiveness and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found;

(p) Procedures for adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment including a breathing apparatus and a rescue harness and line; and

(q) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under paragraph 255.615(a)(3) specifically apply to these reports.

(r) For transmission lines, other than those operated in connection with the operator's distribution system, procedures for the following to provide safety when operating design limits have been exceeded:

(1) responding to, investigating and correcting the cause of:
   (i) unintended closure of valves, or shutdowns;
   (ii) increase or decrease in pressure or flow rate outside normal operating limits;
   (iii) loss of communications;
   (iv) operation of any safety device; and
   (v) any other foreseeable malfunction of component, deviation from normal operation, or personnel error which may result in a hazard to persons or property.

(2) checking variations from normal operation, after abnormal operation has ended, at sufficient critical locations in the system to determine continued integrity and safe operation.

(3) notifying responsible operator personnel when notice of an abnormal operation is received.

(4) periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.

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

255.609 Change in class location: required study.

At least once every five years or whenever an increase in population density indicates either a change in class location for a segment of an existing steel pipeline operating at a hoop stress that is more than 40 percent of SMYS or that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) the present class location for the segment involved;

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

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

(d) the operating and maintenance history of the segment;

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

(f) the actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

255.611 Change in class location: confirmation or revision of maximum allowable operating pressure. (a) Within 60 days after the required study is completed, the operator shall submit a program for redesigning and/or testing the respective pipeline segments, or appropriate reduction of the maximum certified operating pressures thereof, to conform to the respective then current class locations, in accordance with this Part, or declare that the design, testing, and operation of the respective pipeline segments conform to the respective then current class locations.

(b) Where 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.

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

2) If the segment involved has not been previously tested in place as described in paragraph (1) of this subdivision, 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.

3) If the segment of pipeline involved has not been qualified for operation under paragraph (1) or (2) of this subdivision, it must be tested in accordance with the applicable requirements of this Part, and its maximum allowable operating pressure must then be established so as to be equal to or less than each of the following:

(i) 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.

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

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

(c) Confirmation or revision of the maximum allowable operating pressure of segment of pipeline in accordance with this section does not preclude the application of sections 255.553 and 255.555 of this Part.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under section 255.609 of this Part must be completed within 18 months of the change in class location.

(e) Pressure reduction under paragraph (b)(2) of this section within
the 18-month period does not preclude establishing a maximum allowable operating pressure under paragraph (b) (3) of this section at a later date.

255.613 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 section 255.619(a) and (b) of this Part.

255.614 Damage prevention program.  (a) Each operator of a buried pipeline shall carry out a written program to prevent damage to that pipeline by excavation activities in accordance with 16 NYCRR Part 753, Protection of Underground Facilities. Each operator of a buried pipeline, except for gathering lines in Class 1 and 2 locations, must participate in the one-call notification system that covers the areas of the State in which those pipeline facilities are located.
(b) Where the operator has reason to believe damage could be done by the excavation activities, the pipeline must be inspected as frequently as necessary during and after the activities to verify the integrity of the pipeline.
(c) In the case of blasting, each inspection must include a leakage survey.

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:
(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; and
   (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; and
(10) beginning action under section 255.827 of this Part, if
applicable, as soon after the end of the emergency as possible.
(11) Actions required to be taken by a controller during an emergency
in accordance with section 255.631.
(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 subdivision (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; and
(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;
(4) plan how the operator and officials can engage in mutual
 assistance to minimize hazards to life or property; and
(5) offer annual training, at mutually acceptable locations, to
 volunteer fire departments regarding the appropriate response to
gas-related emergencies and to police departments regarding the
recognition of gas-related emergencies. For nonvolunteer fire
departments, annually offer to assist the training coordinator in
developing training programs for gas safety-related matters.
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SO DOC 16B-255.616                              NYCRR
255.616 Customer education and information program.
(a) Except for an operator of a petroleum gas system covered under
paragraph (j) of this section, each 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).
(b) The operator's program must follow the general program
recommendations of API RP 1162 (as described in section 10.3 of the
Title) and assess the unique attributes and characteristics of the
operator's pipeline and facilities.
(c) The operator must follow the general program recommendations of
API RP 1162 (as described in section 10.3 of the Title), unless the
operator provides justification in its program or procedural manual as
to why compliance with all or certain provisions of the recommended
practice is not practicable and not necessary for safety.
(d) The operator's program must specifically include provisions to
educate the public, appropriate government organizations, and persons
engaged in excavation related activities on:
(1) use of a one-call notification system prior to excavation and
other damage prevention activities;
(2) possible hazards associated with unintended releases from a gas pipeline facility;
(3) physical indications that such a release may have occurred;
(4) steps that should be taken for public safety in the event of a gas pipeline release; and
(5) procedures for reporting such an event.
(e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.
(f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.
(g) 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.
(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.
(i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.
(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 gas usage), and to provide information on identifying symptoms of carbon monoxide exposure including recommended remedial measures.

SO DOC 16B-255.619
NYCRR
255.619 Maximum allowable operating pressure: steel or plastic pipelines.
(a) Except as provided in subdivision (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 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;

(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:

<table>
<thead>
<tr>
<th>Factors</th>
<th>Installed before (Nov. 12, 1970)</th>
<th>Installed after (Nov. 11, 1970)</th>
<th>Converted under $\sigma_{255.559}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class Location</td>
<td>1.1</td>
<td>1.1</td>
<td>1.25</td>
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<tr>
<td>1</td>
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<tr>
<td>2</td>
<td>1.4</td>
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<tr>
<td>4</td>
<td>1.4</td>
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<td>1.5</td>
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(3) the highest actual operating pressure to which the segment was subjected during the five years preceding July 1, 1970, unless the segment was tested in accordance with section 255.505 or 255.507 of this Part during the five-year period or the segment was upgraded in accordance with section 255.555 or 255.557 of this Part; The MAOP must not exceed the MAOP on August 30, 2011 if the MAOP is determined using this method.

(4) for furnace butt welded steel pipe, a pressure equal to 60 percent 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 percent of the highest test pressure to which the pipe has been subjected, whether by mill test or by post installation test; or

(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 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 section 255.195 of this Part.

(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 five years preceding July 1, 1970, subject to the requirements of section 255.611 of this Part.

(d) Notwithstanding the limitation of paragraph (a) (3) of this section, an operator may maintain a previously established maximum allowable operating pressure for a cathodically protected steel or plastic pipeline provided that, when the pressure is increased above the highest pressure to which it has been subjected during the last five years, it is leakage surveyed and all leaks found are repaired in accordance with this Part.

SO DOC 16B-255.621

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:
(1) the design pressure of the weakest element in the segment, determined in accordance with this Part;

(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 section 255.197(c) of this Part;

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

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

(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 section 255.195 of this Part.

255.623 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.

(c) Each operator shall maintain a pressure throughout its low-pressure distribution systems, as measured at the consumer's end of the service line, of not less than 4 inches nor more than 12 inches of water column gauge.

(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 two 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 via a transmission pipeline line that transported gas without an odorant from that line before May 5, 1975, is to be adequately odorized in compliance with subdivision 255.625 (c) of this section 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.

(b) All gas transported in distribution mains, except as provided for in subdivision (a) of this section, and service laterals is to be adequately odorized in compliance with subdivision (c) of this section.
so as to render it readily detectable by the public and employees of the operator at all gas concentrations of one tenth of the lower explosive limit and above.

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

(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.

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

(d) Odorization equipment must be designed and maintained so as to 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.

(e) Each operator shall establish procedures to conduct periodic sampling of combustible gases to assure the proper concentration of odorant in accordance with this section. An appropriate record of all odorization practices shall be maintained.

(f) Every operator shall maintain records setting forth the types of odorizing equipment and odorants used, the ratios of odorant to gas, and the locations of odorization stations.

SO DOC 16B-255.627
255.627 Tapping pipelines under pressure. Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.

SO DOC 16B-255.629
255.629 Purging of pipelines. All purging shall be carried out in accordance with Purging Principles and Practice (as described in section 10.3 of this Title), published by the American Gas Association, Inc.

SO DOC 16B-255.631
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 must 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 must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. the procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4) and (e) of this section must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) of this section must be implemented no later than August 1, 2012, except that any training required by
another paragraph of this section must be implemented no later than the deadline for that paragraph.

(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

(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 of SCADA displays;
3. Test and verify an internal communication plan to provide adequate means for manual operation of the piping 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 value 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.

Sections 255.703 through 255.757 of this Part prescribe minimum requirements for maintenance of pipeline facilities.

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this Part.
(b) Each segment of pipeline that becomes unsafe must be replaced, repaired or removed from service.
(c) The provisions of: sections 255.705, 255.706, 255.709, 255.711, 255.713, 255.715, 255.717 and 255.719 of this Part 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.

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

<table>
<thead>
<tr>
<th>Maximum interval between patrols</th>
<th>At highway and railroad crossings</th>
<th>At all other locations</th>
</tr>
</thead>
<tbody>
<tr>
<td>1,2........................7 1/2 months; but at</td>
<td>15 months; but at least</td>
<td></td>
</tr>
</tbody>
</table>
3 ..................4 1/2 months; but at least four times each calendar year.

4..................4 1/2 months; but at least four times each calendar year.

SO DOC 16B-255.706

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.
(b) Leaks located shall be investigated promptly, and necessary action shall be taken in accordance with sections 255.805 and 255.807 of this Part.

SO DOC 16B-255.707

255.707 Line markers for mains and transmission lines. (a) Except as provided in subdivision (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 else necessary to identify the location of the main or transmission line to reduce the possibility of damage or interference.
(b) Line markers are not required for buried mains in Class 3 or 4 locations where a damage prevention program is in effect under section 255.614 of this Part. Line markers are not required for buried transmission lines in Class 3 or 4 locations where placement of a marker is impractical.
(c) 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) The following must be written legibly on a background of sharply contrasting color on each line marker other than at navigable waterways:
(1) the word "Warning," "Caution" or "Danger" followed by the words "Gas" (or name of gas transported) "Pipeline," all of which, except for markers in heavily developed urban areas, must be in letters at least one inch high with one-quarter inch stroke; and
(2) the name of the operator and a telephone number (including area code) where the operator can be reached at all times.
(e) Each line marker at a navigable waterway shall 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 the word "Warning," "Caution" or "Danger" followed by the words "Do not anchor or dredge" and the words "Gas Pipeline Crossing";
(3) the name of the operator and the telephone number (including area code) where the operator can be reached at all times; and
(4) in overcast daylight, the sign is visible and the writing required by paragraph (2) of this subdivision is legible, from approaching or
passing vessels that may damage or interfere with the pipeline.

255.709 Transmission lines: recordkeeping.
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) Temporary repairs. Each operator must 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
   (2) it is not feasible to make a permanent repair at the time of discovery.
(b) Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following:
   (1) Non integrity management repairs: The operator must make permanent repairs as soon as feasible.
   (2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O-Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by paragraph 255.933(d).
   (c) Welded patch. Except as provided in paragraph 255.717(b)(3), no operator may use a welded patch as a means of repair.

255.713 Transmission lines: permanent field repair of imperfections and damages.
(a) Each imperfection or damage that impairs the serviceability of a segment of steel transmission line, or distribution main operating at 125 PSIG (860 kPa) or more in a Class 3 or 4 location, must be repaired according to the following requirements:
   (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, the imperfection or damage must be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
   (b) If the segment is not taken out of service, the operating pressure must be reduced to a safe level during the repair operations.

255.715 Transmission lines: permanent field repair of welds.
Each weld that is unacceptable under section 255.241(c) of this Part 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 of this Part.
   (b) A weld maybe repaired in accordance with section 255.245 of this
Part while the segment 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 percent of SMYS; and
3. grinding of the defective area can be limited so that at least 1/8-inch thickness in the pipe weld remains.

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

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:

(a) If feasible, the segment 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.

(b) If it is not feasible to take the segment out of service, repairs must be made by one of the following methods:
   1. Install a full encirclement welded split sleeve of appropriate design.
   2. If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp; if the leak is due to a corrosion pit and is on pipe with a SMYS of not more than 40,000 psi (267 MPa), the repair may be made by fillet welding 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.
   3. Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

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. This test may be made on the pipe before it is installed provided nondestructive tests meeting the requirements of section 255.243 of this Part are made on all field girth butt welds after installation.

(b) Emergency pipe when retained in stock shall be tested before storage at 90 percent of SMYS or one and one-half times the certified operating pressure, whichever is less. Such pipe shall be appropriately marked and test records retained.

(c) Each repair made by welding in accordance with sections 255.713, 255.715 and 255.717 of this Part must be examined in accordance with section 255.241 of this Part.

255.721 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 patrolled at intervals not exceeding 4 1/2 months, but at least four
times each calendar year.

(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 of this Part.

NYCRR

255.723 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. Leaks located by these surveys shall be investigated promptly and necessary action shall be taken in accordance with sections 255.805 and 255.807 of this Part.

(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 leakage survey with leak detector equipment shall be conducted at intervals not exceeding 15 months, but at least once each calendar year, in business districts within the operator's gas franchise area including tests of the atmosphere of gas, electric, telephone, sewer, and water system manholes, at cracks in pavement, at the curbline, in the sidewalk, and at other locations providing an opportunity for finding gas leaks.

(2) Leakage surveys of the distribution system outside of business districts, must be made as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months.

(3) If the operator employs leakage history to determine areas of active corrosion, the leakage survey frequency shall at least once every 3 calendar years at intervals not exceeding 39 months on mains and service lines.

(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 of this Part.

NYCRR

255.725 Test requirements for reinstating service lines. (a) Except as provided in subdivision (e) of this section, each disconnected service line must be tested in accordance with this section before being reinstated; 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. The limits of the test shall be in accordance with section 255.511(g) of this Part.

(b) For each service line to be operated at a pressure of not more than 20 PSIG (138 kPa), the test pressure shall be three PSIG (21 kPa) or three 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.

(e) All exposed connections on low-pressure service lines temporarily disconnected from the main because of main renewals or other planned work shall be soap-tested at operating pressure and the entire service line shall be checked for leakage with a combustible gas indicator both at the time of turn on and on the following day.
255.726 Inactive service lines.

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 section 255.727(d) of this Part for a period of not more than six years subject to the following conditions:

(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 (d) of this section, purge the service and seal the open end.

(b) In active service lines for which there is a definite plan for future use may remain under the conditions established by section 255.727(d) of this Part 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 (d) of this section, purges the service and seals the open ends by the end of the sixth year of inactivity.

(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.

(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.

(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.

(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; and sealed at the ends except that 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; and sealed at the ends except that 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 apply:

(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 ensure that a combustible mixture is not present after purging.

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

(g) For each abandoned pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility shall file a report upon abandonment of that facility in accordance with 49 CFR 192.727(g) (as described in section 10.2 of this Title).

NYCRR 255.729 Compressor stations: procedures for gas compressor units. Each operator shall establish starting, operating, and shutdown procedures for gas compressor units.

NYCRR 255.731 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 sections 255.739 and 255.743 of this Part, 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 exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

NYCRR 255.732 Compressor stations: additional inspections. (a) All stations shall be inspected for excessive vibration in control piping. All suspect configurations shall be corrected promptly.

(b) All automatic combustible gas alarm and automatic shut-off valve systems in compressor stations shall be inspected weekly.

NYCRR 255.733 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 and for purging before returning to service.

NYCRR 255.735 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) Above ground oil or gasoline storage tanks must be protected in accordance with National Fire Protection Association Standard No. 30 (as described in section 10.3 of this Title).
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:
(1) constructed so that at least 50 percent of its upright side area
is permanently open; or
(2) located in an unattended field compressor station of 1,000
horsepower (746kW) or less.
(b) Except where shutdown of the system is necessary for maintenance
under subdivision (c) of this section, each gas detection and alarm
system required by this section must:
(1) continuously monitor the compressor building for a concentra-
tion of gas in air of not more than 25 percent of the lower explosive limit; and
(2) if that concentration of gas is detected, warn persons about to
enter the building and persons inside the building of the danger.
(c) Each gas detection and alarm
system required by this section must
be maintained to function properly. The maintenance must include
performance tests.

255.737 Pipe-type and bottle-type gas holders. Whenever a pipe-type or
bottletype gas holder is found, it shall be removed or abandoned unless
specific approval is granted for its continued use.

255.739 Pressure-limiting and -regulating stations: inspection and
testing.
(a) Each pressure-limiting station, relief device (except rupture
discs), and pressure-regulating station and its equipment must be
subjected, at intervals not exceeding 15 months, but at least once each
calendar year, to inspections and tests to determine that:
(1) it is in good mechanical condition;
(2) it is adequate from the standpoint of capacity and reliability of
operation for the service in which it is employed;
(3) except as provided in subdivision (b) of this section, it is set
to function at the correct pressure consistent with the pressure limits
of section 255.201(b) of this part; and
(4) it is properly installed and protected from dirt, liquids or other
conditions that might prevent proper operation.
(b) For steel pipelines whose MAOP is determined under section
192.619(c) of this Part, if the MAOP is 60 psi (414 kPa) gage or more,
the control or relief pressure limit is as follows:

<table>
<thead>
<tr>
<th>If the MAOP produces a hoop stress that is:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greater than 72 percent of SMYS</td>
</tr>
<tr>
<td>Unknown as a percentage of SMYS</td>
</tr>
</tbody>
</table>

(c) If during the annual or any other regulating station inspection,
the inspector finds that the regulator is not adequately protected from
dirt or liquids, or does not respond properly to performance tests, an
internal inspection shall be conducted and parts thereof overhauled to
the extent necessary.
(d) The operating condition of all operating pressure regulator stations except field regulators shall be inspected at least once each month. Such inspection shall include proper tests for gas leaks. A test with a combustible gas indicating instrument shall be conducted in all operating regulator stations contained in vaults, pits or other enclosed below grade and any unventilated aboveground building areas.

(e) All stations shall be inspected periodically for excessive vibration in control piping. All suspect configuration shall be corrected promptly.

(f) All combustible gas alarm systems shall be inspected in accordance with the manufacturer's recommended instructions.

255.741 Pressure-limiting and -regulating stations: telemetering or recording gauges.

(a) Each distribution system supplied by more than one district pressure-regulating station must be equipped with telemetering or recording pressure gauges 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 gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

(c) For low-pressure distribution systems, the telemetering or recording pressure gauges are to be located at, or near each district regulator outlet and the probable locations of minimum pressures in each part of the system.

(d) The accuracy of each recording pressure gauge provided and maintained by each operator at the locations required herein shall be tested at intervals not exceeding 15 months, but at least once each calendar year. The results of the tests shall be recorded.

(e) Each chart removed from a recording pressure gauge shall be reviewed for indications of abnormally high or low pressure. If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected and the necessary measures taken to correct any unsatisfactory operating conditions.

(f) Each chart removed from a recording pressure gauge shall be marked with the name of the operator, the location of the gauge, the date that it was placed upon the gauge, and the date that it was removed from the gauge prior to its filing.

255.743 Pressure-limiting and -regulating stations: testing relief device. (a) Overpressure protection devices shall be tested in place annually to determine if they are in proper working condition. They are to be subjected to such maintenance and overhaul as may be indicated by said tests. Overpressure protection devices used solely for the protection of "fuel piping" as, for example, to compressors at the compressor stations, shall be tested and inspected in like manner.

(b) Nonworking monitoring regulator equipment shall be subject to an annual performance test and shall be internally inspected and overhauled if so required by the results of the test.

(c) An annual review of the required capacity of the relieving equipment at each station shall be made and these required capacities compared with the calculated or experimentally determined recorded
relieving capacity of the installed equipment for the operating conditions under which it works.

(d) If the relieving equipment is of insufficient capacity, a new or additional device shall be installed to provide the additional capacity required or the station regulator capacity reduced commensurate with the existing relief capacity.

255.744 Service regulators and vents: inspection. (a) Each operator shall inspect each service regulator when it is installed, at the time of periodic meter change, and at the time a service which has been inactive for a period of two years or more is reactivated to service.

(b) An operator may elect to inspect service regulators at intervals not to exceed 20 years in lieu of inspection at the time of periodic meter change.

(c) Service regulators serving multiple meter installations need not be inspected at the time of each individual meter change, however, each associated regulator shall be inspected at least once each 20 years.

(d) The inspection of the service regulator shall include the following tests:

(1) An outlet pressure test shall be taken under minimum load conditions. Minimum load condition, for purposes of this paragraph, shall mean no load or pilot load only. The pressure limits of this test shall be as established by this Part.

(2) The operational pressure test shall be taken on the outlet side of the regulator with one or more appliances in operation. The acceptable limits of pressure shall be as established by this Part.

(e) Each operator shall inspect each service regulator associated vent whenever the service regulator is inspected. This inspection shall include a test for the presence of gas, proper location of vent terminus, proper size, and proper installation of a weather-insect resistant fitting and verification by an inside the building inspection that the vent line piping is continuous and is properly connected to the regulator. Immediate remedial action shall be taken if any of these items do not pass inspection.

255.745 Valve maintenance: transmission lines.

(a) Each transmission line valve must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

(b) Each operator must take prompt remedial action to correct any valve found inoperable.

(c) The location of all valves in transmission lines shall be designated on appropriate records, drawings or maps in relation to aboveground structures, so that the valves and associated access covers can be readily located when the ground is covered with snow and ice. Since there may be changes or alterations in aboveground structures over a period of time, the accuracy of the reference points established shall be verified at the time of the periodic inspection.

(d) At the time of the periodic inspection, valves will be checked for external leakage.

255.747 Valve maintenance: distribution systems.

(a) Each valve, the use of which may be necessary for the safe shutdown or sectionalization of a distribution system, must be inspected
and partially operated at intervals not exceeding 15 months, but at least once each calendar year. Included are the principal shut-off valves at district regulator stations and pressure-limiting devices.

(b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

(c) The location of all valves in distribution systems that may be required during an emergency shall be designated on appropriate records, drawings or maps, in relation to aboveground structures, so that the valves and associated access covers can be readily located when the ground is covered with snow and ice. Since there may be changes or alterations in aboveground structures over a period of time, the accuracy of the reference points established shall be verified at the time of the periodic inspection.

(d) At the time of the periodic inspection, valves will be checked for external leakage.

255.748 Valve maintenance: service line valves.

(a) Except as provided in subdivision (b) of this section, buried high-pressure service line valves or exposed exterior high-pressure service line valves shall be inspected in conjunction with the service regulator inspection required under section 255.744 of this Part.

(b) Buried service line valves used for compliance with section 255.365(b)(2) of this Part shall be inspected at intervals not exceeding 15 months, but at least once each calendar year, for accessibility, key alignment and external leakage.

(c) Each buried service line valve inspection shall determine accessibility, key alignment and tests for external leakage. Each exposed exterior service line valve shall be inspected for accessibility and external leakage.

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.

(b) If gas is found in the vault, the equipment in the vault must be inspected for leaks, and any hazardous leaks found must be repaired immediately.

(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.

255.751 Prevention of accidental ignition. Each operator shall take the following minimum 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.

(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) Warning signs are to be posted where appropriate.
(d) Precautions to prevent uncontrolled or unsafe static electric discharges from plastic pipe are to be taken.

255.753 Caulked bell and spigot joints.
(a) Each cast iron caulked bell and spigot joint that is subject to pressures of 25 psig (172 kPa) or more must be sealed with a material or device which:
   (1) does not reduce the flexibility of the joint;
   (2) permanently bonds, either chemically, mechanically or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and
   (3) seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of subdivisions 255.53 (a) and (b) and section 255.143 of this Part.
(b) Each cast iron caulked bell and spigot joint that is exposed for any reason, must be sealed by a means other than caulking.

255.755 Protecting cast iron pipelines. When an operator has knowledge that the support for a segment of a buried cast iron pipeline is disturbed, the following actions must be taken.
(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 sections 255.317, 255.319 and 255.361(b)-(d) of this Part.

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:
   (1) the cast iron main is to be replaced prior to the third-party construction activity occurring; or
   (2) the cast iron main is to be surveilled for leakage daily until the contractor allows access to the excavation area for replacement. After access is allowed, the operator is to immediately replace the affected cast iron main or maintain daily surveillance with an open vent hole and replace the cast iron main as soon as practical.
(b) For right angle crossings of cast iron mains, the length replaced shall be equal to at least the width of the excavation plus twice the distance from the top of the main to the bottom of the trench.
(c) For crossings of cast iron mains at other than right angles, the
length of the replacement shall be increased so that all cast iron pipe will be removed from within the trench settlement area under the gas main, assuming an angle of repose of 45 degrees from the bottom of the trench.

(d) Where replacement of cast iron main is required it shall extend approximately equally on both sides of said excavations.

255.757 Replacement of cast iron mains paralleling excavations. (a) If an excavation is made parallel to any cast iron gas main, eight inches or less in nominal diameter, and said excavation is not adequately shored to protect the cast iron main against movement, the cast iron main must be replaced where more than half the pipe diameter lies above a line projected at an angle above the horizontal equal to the angle of repose for the soil conditions being encountered, starting from the bottom of the excavation at the side nearest the main.

(b) Replacement is to be completed prior to the third-party construction activity, if possible. Otherwise, replacement is to commence immediately after the contractor allows access to the excavation area for replacement and the area is to be maintained under daily leakage survey until replacement is complete.

255.801 Reports of accidents.

(a) Each operator shall report all accidents where gas facilities may be involved, which cause injury or death to any person or damage to property, or could cause concern because of coverage by news media.

(b) All incidents involving carbon monoxide (CO) that result in an investigation by the company shall also be reported.

(c) All such accidents and CO incidents shall be immediately reported by telephone through the gas emergency notification system.

(d) Within 30 days written account shall be submitted for each incident that involved gas facilities and:

(1) a death, or personal injury necessitating inpatient hospitalization; or

(2) estimated property damage, including cost of gas lost, of the operator, or others, or both, of $50,000 or more.

(e) This report shall set forth a chronological sequence of events including a detailed description of the:

(1) accident (incident);

(2) response, action and investigation by the operator; and

(3) results and findings of the investigations.

(f) Such written account for a CO incident shall only be required when it resulted in either an injury or fatality.

(g) Where applicable, a copy of the report sent to the Office of Pipeline Safety, United States Department of Transportation shall be submitted by the operator.

255.803 Emergency lists of operator personnel. Each operator shall submit a list during January of each year indicating the names, addresses, and home and business telephone numbers of responsible officials who may be contacted in the event of an emergency. The list shall also be submitted to all municipalities within which the operator's facilities are located. In the event of any changes in the list within the year, immediate notification thereof shall be given to all recipients.
255.805 Leaks: general. (a) Any notification of a gas leak or gas odor, or any notification of damage to facilities by contractors or other outside sources shall constitute the need for prompt action.

(b) Each operator shall be responsible for the leak investigation, classification, and repair of each leak found on its below-grade system and shall establish a means by which it determines the appropriate surveillance interval at leak locations under frost conditions.

(c) Leaks found to be on exposed piping or facilities need not be classified; however, each operator shall establish procedures for immediate elimination of potential hazards resulting therefrom.

(d) The purpose of the leak classification system is to determine the degree or extent of the potential hazard which results from gas leakage and to prescribe remedial actions therefor.

(e) Classifications shall be made only by individuals who possess training, experience, and knowledge in the field of leak classification and investigation, including extensive association with actual leakage work. The judgment of the aforementioned individuals, based upon all pertinent information and a complete leakage investigation at the scene, will form the basis for the classification.

(f) Percentages of gas-in-air included hereafter are based on natural gas. Where liquefied petroleum, manufactured or other gases are involved, appropriate adjustment shall be made as may be required, consistent with the lower explosive limit (LEL) of such gas or mixture of gases.

(g) Prior to downgrading a leak without any repair, at least one additional surveillance at the normal interval is required to verify that a lower class of hazard exists. Except for leaks downgraded to type 3 classification, which do not require a time limit for repair, if a leak is reclassified to a lower hazard level, the original date of discovery determines the time period for repair. In no case shall the time limit for required repair of any leak exceed one year from the date of discovery. This requirement does not apply to leaks classified as type 2 or 2A based on consideration of frost conditions nor to leaks, at the time of discovery, classified at a higher level pending a further, more complete investigation of the leak hazard area.

(h) When a leak is upgraded to a higher hazard level, the time period for repair is the remaining time based on its original classification or the time allowed for its new classification, whichever is less. This does not apply to leaks classified at a higher hazard level based on consideration of frost conditions nor to leaks, at the time of discovery, classified at a lower level pending a further, more complete investigation of the leak hazard area.

255.807 Leaks: records. (a) A gas leak record, identified by number, shall be used to depict the entire history of a leak from the time of discovery through the follow-up inspection.

(b) The record shall contain information as to the nature of the repair and follow-up results.

(c) Leaks shall only be classified or reclassified by a responsible and experienced individual whose name shall appear on the record.

(d) The gas leak record shall contain an adequate number of readings from the sample points tested during the leakage investigation to depict the extent of hazardous gas migration, expressed in percent gas-in-air
or percent LEL found at the time of classification, reclassification if applicable, surveillance investigations, during leak repair activities, after completion of repairs, and at any follow-up inspections.

NYCRR 255.809 Leaks: instrument sensitivity verification. Each instrument utilized for leakage surveys and investigations must be tested against a known sample or in accordance with the manufacturer's recommended instructions as follows:

(a) after any repair or replacement of parts other than normal maintenance;
(b) once every three months for CGI's and solid-state leak detection instruments and yearly for hydrogen flame ionization (HFI) instruments; and
(c) any time it is suspected that the calibration has changed.

NYCRR 255.811 Leaks: type 1 classification. (a) A type 1 leak is one which, due to its location and/or relative magnitude, constitutes a potentially hazardous condition to the public or buildings.
(b) A type 1 leak requires an immediate effort to protect life and property.
(c) Continuous action shall be thereafter taken until the condition is no longer hazardous.
(d) Completion of repairs shall be scheduled on a regular day-after-day basis, or the condition kept under daily surveillance until the source of the leak has been corrected.
(e) Type 1 leaks include, but are not limited to:
1. damage by contractors or outside sources resulting in leakage;
2. any indication on a combustible gas indicator (CGI) of natural gas entering buildings or tunnels;
3. any reading on a CGI with five feet (1.5 meters) of a building wall;
4. any reading of four percent or greater gas-in-air on a CGI within manholes, vaults or catch basins (sampling will be conducted with the structure in its normal condition as nearly as physically possible); or
5. any leak which, in the judgment of the operating personnel at the scene, is regarded as potentially hazardous.

NYCRR 255.813 Leaks: Type 2A classification. (a) A type 2A leak does not present an immediately hazardous condition to the public or buildings, but is of a nature that requires frequent surveillance and scheduled repair.
(b) Type 2A leaks shall be repaired within a period not to exceed six months.
(c) Type 2A leaks shall be maintained under surveillance with a frequency not to exceed two weeks until repaired.
(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 five feet (1.5 meters) but within 20 feet (6.1 meters) of the building and inside the curb or shoulder of the road; or (3) any leak, other than type 1, which, under frost or other
conditions, in the judgment of the operating personnel at the scene should be classified as a type 2A.

255.815 Leaks: type 2 classification.
(a) A type 2 leak does not present an immediate hazardous condition to the public or buildings, but is of a nature requiring scheduled repair.
(b) Type 2 leaks shall be repaired within a period not to exceed one year, except that leaks classified under paragraph (d)(5) of this section shall be repaired within six months.
(c) Type 2 leaks shall be maintained under surveillance with a frequency not to exceed two months, except that leaks classified under paragraph (d)(5) of this section shall be surveilled every two weeks.
(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
   (5) any reading above one percent but below four percent gas-in-air, within manholes, vaults or catch basins (sampling will be conducted with the structure in its normal condition as nearly as is physically possible).

255.817 Leaks: type 3 classification. (a) A type 3 leak is not immediately hazardous at the time of detection and can be reasonably expected to remain that way.
(b) A type 3 leak is any leak not classified as type 1, 2A or 2.
(c) Type 3 leaks shall be reevaluated during the next required leakage survey or annually, whichever is less.

255.819 Leaks: follow-up inspection. (a) Each operator shall, upon completing a type 1, type 2A or type 2 leak repair to its underground facilities, conduct a follow-up inspection at least 14 days after but within 30 days of the repair to validate said repair.
(b) Follow-up inspections are not required for leak repairs completed by the replacement or insertion of an entire length of pipe or service line, or for the repair of leakage caused by contractor or third-party damage, provided a complete reevaluation of the leak area after completion of repairs verifies that no further indications of leakage exist.
(c) Remedial measures such as lubrication of valves or tightening of packing nuts on valves which seal leaks may be considered to be routine maintenance work and do not require a follow-up inspection.
(d) Appropriate records shall be kept.

255.821 Leaks: nonreportable reading. Whenever an operator conducts an annual leakage survey of all mains, or a portion of the mains, in its distribution system, any sustained reading of four percent or less gas-in-air on a CGI at an isolated test point outside the curbline or shoulder of the road can be considered a nonreportable reading except where found in manholes, vaults or catch basins.

255.823 Interruptions of service. (a) Any major interruption of service furnished by any pipeline, or the failure of any major equipment thereof, or any other interruption or failure of such facilities which could cause public concern because of coverage by news media, is to be immediately reported by telephone.

(b) Within 30 days, a written report of the interruption or failure shall be submitted including the chronological sequence of events related to the interruption, including a detailed description of the:
   (1) interruption;
   (2) response, action and investigation by the operator; and
   (3) results and findings of the investigation.

(c) Where applicable, a copy of the report sent to the Office of Pipeline Safety, United States Department of Transportation is to be submitted by the operator.

(d) This requirement does not apply to scheduled interruptions of service, or interruptions in accordance with the provisions of contracts between the operator and its customers.

(e) This requirement is in addition to reporting requirements of Part 232 of this Title.

255.825 Logging and analysis of gas emergency reports. (a) Each operator shall appropriately record each report received by it as to a gas leak or emergency on a suitably numbered service record.

(b) A daily log shall be kept and maintained on file recording the receipt and handling of each such report and shall contain the following information:
   (1) cross-reference to the related service record number;
   (2) location of leak or emergency;
   (3) time report first received by operator;
   (4) description or code designation as to type of leak or emergency;
   (5) time crew first dispatched to designated location; and
   (6) time of arrival of such personnel at location.

(c) In addition, every operator shall maintain a record of the time of arrival of the repair crew called to the scene of a gas leak or emergency.

(d) Every operator shall submit, on or before the 15th day of each calendar month, a summary analysis of its performance in responding to reports of gas leaks, as reflected in the daily log sheets for the preceding calendar month, which shall be furnished in a format identical to Form A of Appendix 7-E of this Title, and which shall be signed by a responsible official.

255.827 Facility failure investigation.

(a) Each operator shall establish procedures to analyze each failure or accident for the purpose of determining its cause and to minimize the
possibility of a recurrence. This plan shall include a procedure to select samples of the failed facility or equipment for laboratory examination when necessary.

(b) The procedures shall also provide for complete cooperation with the 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.

255.829 Annual report. Each operator shall submit a copy of the annual report sent to the Office of Pipeline Safety, United States Department of Transportation not later than March 15th of each year.

255.831 Reporting safety-related conditions. Each operator shall submit a report on the existence of any of the applicable safety-related conditions involving facilities in service in accordance with sections 23 and 25 of title 49, Code of Federal Regulations, Part 191, Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety Related Condition Reports (as described in section 10.2 of this Title).

255.901 Scope. Sections 255.901 through 255.951 of this Part prescribe minimum requirements for an integrity management program on any gas transmission pipeline covered under this Part. For gas transmission pipelines constructed of plastic, only the requirements in Sections 255.917, 255.921, 255.935 and 255.937 of this Part apply.

255.903 Definitions. The following definitions apply to sections 255.901 through 255.951 of this Part:

(a) Assessment is the use of testing techniques as allowed in sections 255.901 through 255.951 of this Part to ascertain the condition of a covered pipeline segment.

(b) Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

(c) Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in section 255.3 of this Part.

(d) Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

(e) High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as-

(i) A Class 3 location under section 255.5 of this Part; or
(ii) A Class 4 location under section 255.5 of this Part; or
(iii) Any area in a Class 1 or Class 2 location where the potential
impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either paragraphs (1) or (2) of this subdivision to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See Figure 1 in Appendix 14-E.)

(4) If in identifying a high consequence area under subparagraph (1)(iii) of this subdivision or subparagraph (2)(i) of this subdivision, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to 20 x 660 feet (or 200 meters) / potential impact radius in feet or meters^2).

(f) Identified site means each of the following areas:

(1) An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility; or

(2) A building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks; or

(3) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

(g) Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

(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 \( r = 0.69 \times \sqrt{pd^2} \), 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 (as described in section 10.3 of this Title) to calculate the impact radius formula.

(i) Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

255.905 High consequence areas.

(a) General. To determine which segments of an operator's transmission pipeline system are covered by sections 255.901 through 255.951 of this Part, an operator must identify the high consequence areas. An operator must use methods defined in paragraph (1) or (2) of subdivision (f) of section 255.903 of this Part to identify a high consequence area. An operator must use the method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See Appendix 14-E.I for guidance on identifying high consequence areas.)

(b) (1) Identified sites. An operator must identify an identified site, for purposes of sections 255.901 through 255.951 of this Part, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

(i) Visible marking (e.g., a sign); or

(ii) The site is licensed or registered by a Federal, State, or local government agency; or

(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) Newly identified areas. When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in section 255.903 of this Part, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.
(a) General. No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in section 255.911 of this Part and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

(b) Implementation Standards. In carrying out sections 255.901 through 255.951 of this Part, an operator must follow the requirements of sections 255.901 through 255.951 of this Part and of ASME/ANSI B31.8S (as described in section 10.3 of this Title) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between sections 255.901 through 255.951 of this Part and ASME/ANSI B31.8S, the requirements in sections 255.901 through 255.951 of this Part control.

255.909 Changes to an integrity management program.

(a) General. An operator must document any change to its program and the reasons for the change before implementing the change.

(b) Notification. An operator must notify the Department and OPS, in accordance with section 255.949 of this Part, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide the notification within 30 days after adopting this type of change into its program.

255.911 Required elements.

An operator's initial integrity management program begins with a framework (see section 255.907 of this Part) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (as described in section 10.3 of this Title) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with section 255.905 of this Part.

(b) A baseline assessment plan meeting the requirements of section 255.919 and 255.921 of this Part.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (section 255.917 of this Part) and to evaluate the merits of additional preventive and mitigative measures (section 255.935 of this Part) for each covered segment.

(d) A direct assessment plan, if applicable, meeting the requirements of section 255.923 of this Part, and depending on the threat assessed,
of section 255.925, 255.927, or 255.929 of this Part.

(e) Provisions meeting the requirements of section 255.933 of this Part for remediating conditions found during an integrity assessment.

(f) A process for continual evaluation and assessment meeting the requirements of section 255.937 of this Part.

(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of section 255.931 of this Part.

(h) Provisions meeting the requirements of section 255.935 of this Part for adding preventive and mitigative measures to protect the high consequence area.

(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of section 255.945 of this Part.

(j) Record keeping provisions meeting the requirements of section 255.947 of this Part.

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by-
   (1) the Department; and
   (2) OPS

(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to-
   (1) the Department; and
   (2) OPS

(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

(p) A process for identification and assessment of newly-identified high consequence areas. (See sections 255.905 and 255.921 of this Part.)

255.913 Deviation from the requirements of this part.

(a) General. ASME/ANSI B31.8S (as described in section 10.3 of this Title) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in sections 255.901 through 255.951 of this Part, as provided in subdivision (c) of this section.

(b) Exceptional performance. An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

   (1) To deviate from any of the requirements set forth in subdivision (c) of this section, an operator must have a performance-based integrity management program that meets or exceeds the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements-

      (i) A comprehensive process for risk analysis;
      (ii) All risk factor data used to support the program;
      (iii) A comprehensive data integration process;
      (iv) A procedure for applying lessons learned from assessment of
covered pipeline segments to pipeline segments not covered by sections 255.901 through 255.951 of this Part;

(v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;

(vii) Semi-annual performance measures beyond those required in section 255.945 of this Part that are part of the operator's performance plan. (See section 255.911 (i) of this Part.) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to the Department and OPS in accordance with section 255.951 of this Part; and

(viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

(2) In addition to the requirements for the performance-based plan, an operator must-

(i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

(ii) Remediate all anomalies identified in the more recent assessment according to the requirements in section 255.933 of this Part, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

(c) Deviation. Once an operator has demonstrated that it has satisfied the requirements of subdivision (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of sections 255.901 through 255.951 of this Part only in the following instances.

(1) The time frame for reassessment as provided in section 255.939 of this Part except that reassessment by some method allowed under sections 255.901 through 255.951 of this Part (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in section 255.933 of this Part if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

255.915 Knowledge and training.

(a) Supervisory personnel. The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) Persons who carry out assessments and evaluate assessment results. The integrity management program must provide criteria for the qualification of any person-

(1) Who conducts an integrity assessment allowed under sections
255.901 through 255.951 of this Part; or
(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or
(3) Who makes decisions on actions to be taken based on these assessments.
(c) Persons responsible for preventive and mitigative measures. The integrity management program must provide criteria for the qualification of any person-
(1) Who implements preventive and mitigative measures to carry out sections 255.901 through 255.951 of this Part, including the marking and locating of buried structures; or
(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

255.917 Identification of potential threats to pipeline integrity and use of the threat identification in an integrity program.
(a) Threat identification. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (as described in section 10.3 of this Title), section 2 which are grouped under the following four categories:
(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;
(2) Static or resident threats, such as fabrication or construction defects;
(3) Time independent threats such as third party damage and outside force damage; and
(4) Human error.
(b) Data gathering and integration. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.
(c) Risk assessment. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (sections 255.919, 255.921, 255.937 of this Part), and to determine what additional preventive and mitigative measures are needed (section 255.935 of this Part) for the covered segment.
(d) Plastic transmission pipeline. An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.
(e) Actions to address particular threats. If an operator identifies any of the following threats, the operator must take the following actions to address the threat.
(1) Third party damage. An operator must utilize the data integration required in subdivision (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with section 255.935 of this Part and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under section 255.921 of this Part, or a reassessment under section 255.937 of this Part, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) Cyclic fatigue. An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

(3) Manufacturing and construction defects. If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.
   (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;
   (ii) MAOP increases; or
   (iii) The stresses leading to cyclic fatigue increase.

(4) ERW pipe. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritizes the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(5) Corrosion. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line
(conditions specified in section 255.931 of this Part), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's operating and maintenance procedures established under 49 CFR Part 192 for testing and repair.

NYCRR 255.919 Baseline assessment plan.

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See section 255.917 of this Part);

(b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (See section 255.917 of this Part) More than one method may be required to address all the threats to the covered pipeline segment;

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

(d) If applicable, a direct assessment plan that meets the requirements of section 255.923 of this Part, and depending on the threat to be addressed, of sections 255.925, 255.927, or 255.929 of this Part; and

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

NYCRR 255.921 Conducting a baseline assessment.

(a) Assessment methods. An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See section 255.917 of this Part).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (as described in section 10.3 of this Title), section 6.2 in selecting the appropriate internal inspection tools for the covered segment;

(2) Pressure test conducted in accordance with the testing requirements of this Part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with section 255.939 of this Part;

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in section 255.923 of this Part and with, as applicable, the requirements specified in sections 255.925, 255.927 or 255.929 of this Part;
(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Department and OPS 180 days before conducting the assessment, in accordance with section 255.949 of this Part.

(b) Prioritizing segments. An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in section 255.917 of this Part.

(c) Assessment for particular threats. In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in section 255.917(e) of this Part to address particular threats that it has identified.

(d) Time period. An operator must prioritize all the covered segments for assessment in accordance with section 255.917(c) of this Part and subdivision (b) above. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) Prior assessment. An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this Part and subsequent remedial actions to address the conditions listed in section 255.933 of this Part have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of sections 255.937 and 255.939 of this Part.

(f) Newly identified areas. When an operator identifies a new high consequence area (see section 255.905 of this Part), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) Newly installed pipe. An operator must complete the baseline assessment of a newly installed segment of pipe covered by this Part within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) Plastic transmission pipeline. If the threat analysis required in section 255.917(d) of this Part on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of section 255.917 of this Part. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.
corrosion (ICDA), and stress corrosion cracking (SCCDA).

(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 RP0502 (as described in section 10.3 of this Title); and section 255.925 of this Part if addressing external corrosion (ECDA).

(2) ASME/ANSI B31.8S, section 6.4 and appendix B2, and section 255.927 of this Part if addressing internal corrosion (ICDA).

(3) ASME/ANSI B31.8S, appendix A3, and section 255.929 if addressing stress corrosion cracking (SCCDA).

(c) Supplemental method. An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in section 255.931 of this Part.

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 RP0502 (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 RP0502, 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 RP0502, 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 RP0502, section 4, the plan's procedures for indirect examination of the ECDA regions must include-

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

(ii) 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;

(iii) 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

(iv) 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 RP0502, 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 RP0502), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502);

(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 RP0502.

(4) Post assessment and continuing evaluation. In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE RP0502, 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 RP0502.)

255.927 Internal corrosion direct assessment (ICDA).

(a) Definition. Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas.

(b) General requirements. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (as described in section 10.3 of this Title), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a
segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with section 255.921 (a)(4) or 255.937(c)(4) of this Part.

(c) The ICDA plan. An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(1) Reassessment. In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to-

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;
(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (See paragraph (a) of this section.) This information includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;
(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and
(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) ICDA region identification. An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," (as described in section 10.3 of this Title). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations downstream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

(3) Identification of locations for excavation and direct examination. An operator's plan must identify the locations where internal corrosion is most likely in each ICDA Region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must
perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must-

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with section 255.933 of this Part;

(ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA Region, or use an alternative assessment method allowed by sections 255.901 through 255.951 of this Part to assess the line pipe in each covered segment within the ICDA Region for internal corrosion; and

(iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA Region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with section 255.933 of this Part.

(4) Post-assessment evaluation and monitoring. An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes-

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in section 255.939 of this Part. An operator must carry out this evaluation within a year of conducting an ICDA; and

(ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of sections 255.901 through 255.951 of this Part, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with section 255.933 of this Part.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by sections 255.901 through 255.951 of this Part.

(5) Other requirements. The ICDA plan must also include-

(i) Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and
(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of section 255.933 of this Part may be limited to covered segments.

255.929 Direct assessment for stress corrosion cracking (SCCDA).

(a) Definition. Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) General requirements. An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for-

(1) Data gathering and integration. An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (as described in section 10.3 of this Title), Appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, Appendix A3.

(2) Assessment method. The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, Appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, Appendix A3, section A3.4.

255.931 Confirmatory direct assessment (CDA).

An operator using the confirmatory direct assessment (CDA) method as allowed in section 255.937 of this Part must have a plan that meets the requirements of this section and of sections 255.925 (ECDA) and 255.927 of this Part (ICDA).

(a) Threats. An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

(b) External corrosion plan. An operator's CDA plan for identifying external corrosion must comply with section 255.925 of this Part with the following exceptions.

(1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

(2) The procedures for direct examination and remediation must provide that-

(i) All immediate action indications must be excavated for each ECDA region; and

(ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

(c) Internal corrosion plan. An operator's CDA plan for identifying internal corrosion must comply with section 255.927 of this Part except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(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 (as described in section 10.3 of this Title), sections 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.

(a) General requirements. An operator must take prompt action to 
direct the assessment. The operator must be able to demonstrate that the 
remediation of the condition will ensure that the condition is unlikely 
to pose a threat to the integrity of the pipeline until the next 
reassessment of the covered segment. If an operator is unable to respond 
within the time limits for certain conditions specified in this section, 
the operator must temporarily reduce the operating pressure of the 
pipe or take other action that ensures the safety of the covered 
segment. If pressure is reduced, an operator must determine the 
temporary reduction in operating pressure using ASME/ANSI B31G (as 
described in section 10.3 of this Title) or AGA Pipeline Research 
Committee Project PR-3-805 ("RSTRENG"; as described in section 10.3 of 
this Title) or reduce the operating pressure to a level not exceeding 
80% of the level at the time the condition was discovered. A reduction 
in operating pressure cannot exceed 365 days without an operator 
providing a technical justification that the continued pressure 
restriction will not jeopardize the integrity of the pipeline.

(b) Discovery of condition. Discovery of a condition occurs when an 
operator has adequate information about a condition to determine that 
the condition presents a potential threat to the integrity of the 
operator must promptly, but no later than 180 days after 
conducting an integrity assessment, obtain sufficient information about 
the condition to make that determination, unless the operator demonstrates 
that the 180-day period is impracticable.

(c) Schedule for evaluation and remediation. An operator must complete 
remediation of a condition according to a schedule that prioritizes the 
conditions for evaluation and remediation. Unless a special requirement 
for remediating certain conditions applies, as provided in subdivision 
(d) of this section, an operator must follow the schedule in ASME/ANSI 
B31.8S (as described in section 10.3 of this Title), section 7, Figure 
4. If an operator cannot meet the schedule for any condition, the 
operator must justify the reasons why it cannot meet the schedule and 
that the changed schedule will not jeopardize public safety. An operator 
must notify the Department and OPS in accordance with section 255.949 of 
this part if it cannot meet the schedule and cannot provide safety 
through a temporary reduction in operating pressure or other action.

(d) Special requirements for scheduling remediation.

(1) Immediate repair conditions. An operator's evaluation and 
remediation schedule must follow ASME/ANSI B31.8S, section 7 in
providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in section 10.3 of this Title.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(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 (upper 2/3 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 1/3 of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 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.

NYCRR 255.935 Preventive and mitigative measures to protect the high consequence areas.

(a) General requirements. An operator must take additional measures beyond those already required by this Part to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high
consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See section 255.917 of this Part) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (as described in section 10.3 of this Title), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(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-

(i) Using qualified personnel (see section 255.915 of this Part) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under sections 255.801 (a) and 255.831 of this Part.

(iii) Participating in one-call systems in locations where covered segments are present.

(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 (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.

(2) Outside force damage. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors - swiftness of leak detection and pipe shutdown
capabilities, the type of gas being transported, operating pressure, the
rate of potential release, pipeline profile, the potential for ignition,
and location of nearest response personnel.

(d) Pipelines operating below 30% SMYS. An operator of a transmission
pipeline operating below 30% SMYS located in a high consequence area
must follow the requirements in paragraphs (1) and (2) of this
subdivision. An operator of a transmission pipeline operating below 30%
SMYS located in a Class 3 or Class 4 area but not in a high consequence
area must follow the requirements in paragraphs (1), (2) and (3) of this
subdivision.

(1) Apply the requirements in subparagraphs (i) and (iii) of paragraph
(1) of subdivision (b) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols
as required by section 255.705 of this Part of the pipeline at
bi-monthly intervals. If an operator finds any indication of unreported
construction activity, the operator must conduct a follow up
investigation to determine if mechanical damage has occurred.

(3) Perform semi-annual leak surveys (quarterly for unprotected
pipelines or cathodically protected pipe where electrical surveys are
impractical).

(e) Plastic transmission pipeline. An operator of a plastic
transmission pipeline must apply the requirements in subparagraphs (i),
(iii) and (iv) of paragraph (1) of subdivision (b) of this section to
the covered segments of the pipeline.

255.937 Continual process of evaluation and assessment.

(a) General. After completing the baseline integrity assessment of a
covered segment, an operator must continue to assess the line pipe of
that segment at the intervals specified in section 255.939 of this Part
and periodically evaluate the integrity of each covered pipeline segment
as provided in subdivision (b) of this section. An operator must
reassess a covered segment on which a prior assessment is credited as a
baseline under section 255.921(e) of this Part by no later than December
17, 2009. An operator must reassess a covered segment on which a
baseline assessment is conducted during the baseline period specified in
section 255.921(d) of this Part by no later than seven years after the
baseline assessment of that covered segment unless the evaluation under
subdivision (b) of this section indicates earlier reassessment.

(b) Evaluation. An operator must conduct a periodic evaluation as
frequently as needed to assure the integrity of each covered segment.
The periodic evaluation must be based on a data integration and risk
assessment of the entire pipeline as specified in section 255.917 of
this Part. For plastic transmission pipelines, the periodic evaluation
is based on the threat analysis specified in section 255.917(d) of this
Part. For all other transmission pipelines, the evaluation must
consider the past and present integrity assessment results, data
integration and risk assessment information (section 255.917 of this
Part), and decisions about remediation (section 255.933 of this Part)
and additional preventive and mitigative actions (section 255.935 of
this Part). An operator must use the results from this evaluation to
identify the threats specific to each covered segment and the risk
represented by these threats.

(c) Assessment methods. In conducting the integrity reassessment, an
operator must assess the integrity of the line pipe in the covered
segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (see section 255.917 of this Part), or by confirmatory direct assessment under the conditions specified in section 255.931 of this Part.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (as described in section 10.3 of this Title), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with the testing requirements of this Part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with section 255.939 of this Part.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in section 255.923 of this Part and with as applicable, the requirements specified in section 255.925, 255.927 or 255.929 of this Part;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Department and OPS 180 days before conducting the assessment, in accordance with section 255.949 of this Part.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with section 255.931 of this Part.

255.939 Reassessment intervals.

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

(a) Pipelines operating at or above 30% SMYS. An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with section 255.931 of this Part. The table that follows this section sets forth the maximum allowed reassessment intervals.

(i) Pressure test or internal inspection or other equivalent technology. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by-

(ii) Basing the interval on the identified threats for the covered segment (see section 255.917 of this Part) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by section 255.917 of this Part; or

(ii) Using the intervals specified for different stress levels of
pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S, section 5, Table 3.

(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 RP0502 (as described in section 10.3 of this Title).

(3) Internal Corrosion or SCC Direct Assessment. An operator that uses ICDA or SCCDA in accordance with the requirements of sections 255.901 through 255.951 of this Part must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

(i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;
(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCICDA segment; and
(iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

(b) Pipelines Operating Below 30% SMYS. An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following:

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in subparagraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with section 255.931 of this Part, or a low stress reassessment in accordance with section 255.941 of this Part.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with section 255.931 of this Part, with reassessment by one of the methods listed in paragraphs (1) through (3) of subdivision (b) of this section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with section 255.941 of this Part with reassessment by one of the methods listed in paragraphs (1) through (3) of subdivision (b) of this section by year 20 of the interval.

(6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix 14-E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control.

An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:
## MAXIMUM REASSESSMENT INTERVAL

<table>
<thead>
<tr>
<th>Assessment method</th>
<th>Pipeline operating at or above 50% SMYS</th>
<th>Pipeline operating at or above 30% SMYS, up to 50% SMYS</th>
<th>Pipeline operating below 30% SMYS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Internal Inspection Tool,</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pressure Test or Direct</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assessment...</td>
<td>10 years(*)...</td>
<td>15 years(*)...</td>
<td>20 years(**)</td>
</tr>
<tr>
<td>Confirmatory Direct</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Assessment...</td>
<td>7 years........</td>
<td>7 years........</td>
<td>7 years</td>
</tr>
<tr>
<td>Low Stress Reassessment...</td>
<td>Not applicable...</td>
<td>Not applicable...</td>
<td>7 years + ongoing actions specified in § 255.941</td>
</tr>
</tbody>
</table>

(*) A Confirmatory direct assessment as described in § 255.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

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255.941 Low stress reassessment.

(a) General. An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with section 255.939 of this Part. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of sections 255.919 and 255.921 of this Part.

(b) External corrosion. An operator must take one of the following actions to address external corrosion on the low stress covered segment.

1. Cathodically protected pipe. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

2. Unprotected pipe or cathodically protected pipe where electrical surveys are impractical. If an electrical survey is impractical on the covered segment an operator must-

   (i) Conduct leakage surveys as required by section 255.706 of this Part, at 4-month intervals; and
(ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(c) Internal corrosion. To address the threat of internal corrosion on a covered segment, an operator must-

(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (1) and (2) of subdivision (c) with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

255.943 Deviation from reassessment intervals.

(a) Waiver from reassessment interval in limited situations. In the following limited instances, the Department and OPS may allow a waiver from a reassessment interval required by section 255.939 of this Part if the Department and OPS find a waiver would not be inconsistent with pipeline safety.

(1) Lack of internal inspection tools. An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) Maintain product supply. An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(b) How to apply. If one of the conditions specified in paragraph (1) or (2) of subdivision (a) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. section 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

255.945 Measuring program effectiveness.

(a) General. An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (as described in section 10.3 of this Title), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by 49 CFR Section 191.17.
(b) External Corrosion Direct Assessment. In addition to the general requirements for performance measures in subdivision (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of section 255.925 of this Part.

255.947 Records.
An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of sections 255.901 through 255.951 of this Part. At minimum, an operator must maintain the following records for review during an inspection.
(a) A written integrity management program in accordance with section 255.907 of this Part;
(b) Documents supporting the threat identification and risk assessment in accordance with section 255.917 of this Part;
(c) A written baseline assessment plan in accordance with section 255.919 of this Part;
(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;
(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with sections 255.915 of this Part;
(f) Schedule required by section 255.933 of this Part that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule;
(g) Documents to carry out the requirements in sections 255.923 through 255.929 of this Part for a direct assessment plan;
(h) Documents to carry out the requirements in section 255.931 of this Part, for confirmatory direct assessment;
(i) Verification that an operator has provided any documentation or notification required by sections 255.901 through 255.951 of this Part to be provided to the Department and OPS.

255.949 Notifications requirements.
An operator must submit any notification required by sections 255.901 through 255.951 of this Part. Such notification must also be submitted to the U.S. Department of Transportation in accordance with 49 CFR section 192.949.

255.951 Reporting requirements.
An operator must submit any report required by sections 255.901 through 255.951 of this Part to the Department. Such reports must also be submitted to the U.S. Department of Transportation in accordance with 49 CFR section 192.951.

Section 255.1001 Definitions that apply to sections 255.1003 through 255.1015.
The following definitions apply to a GDPIM plan:
(a) Excavation Damage means any impact that results in the need to repair or replace an underground facility due to a weakening, or the partial or complete destruction, of the facility, including, but not limited to, the protective coating, lateral support, cathodic protection or the housing for the line device or facility.

(b) Hazardous Leak means a leak as defined in section 255.811 of this Part.

(c) Gas Distribution Pipeline Integrity Management Plan or GDPIM plan means a written explanation of the mechanisms or procedures the operator will use to implement its GDPIM management program and to ensure compliance with sections 255.1003 through 255.1015.

(d) Gas Distribution Pipeline Integrity Management Program or GDPIM program means an overall approach by an operator to ensure the integrity of its gas distribution system.

(e) Mechanical fitting means a mechanical device used to connect sections of pipe. The term "Mechanical fitting" applies only to:
   (1) Stab Type fittings;
   (2) Nut Follower Type fittings;
   (3) Bolted Type fittings; or
   (4) Other Compression Type fittings.

(f) Small LPG Operator means an operator of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

255.1003 General requirements of a GDPIM plan.

Sections 255.1003 through 255.1015 prescribe the minimum requirements for a GDPIM program for any gas distribution pipeline covered under this part, including liquefied petroleum gas systems. A gas distribution operator, other than a small LPG operator, must follow the requirements in sections 255.1005 through 255.1013. A small LPG operator of a gas distribution pipeline must follow the requirements in section 255.1015.

255.1005 Implementation requirements of a GDPIM plan.

No later than August 2, 2011 a gas distribution operator must develop and implement a GDPIM program that includes a written GDPIM plan as specified in section 255.1007.

255.1007 Required elements of a GDPIM plan.

A written GDPIM plan must contain procedures for developing and implementing the following elements:

(a) Knowledge. An operator must demonstrate an understanding of its gas distribution system developed from reasonably available information.

(1) Identification of the characteristics of the pipeline's design and operations and the environmental factors that are necessary to assess the applicable threats and risks to its gas distribution pipeline.

(2) Consideration of the information gained from past design, operations, and maintenance.

(3) Identification of the additional information needed and provide a plan for gaining that information over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).

(4) Development and implementation of a process by which the GDPIM program will be reviewed periodically and refined and improved as needed.
(5) Provision for the capture and retention of data on any new pipeline installed. The data must include, at a minimum, the location where the new pipeline is installed and the material of which it is constructed.

(b) Identify threats. The operator must consider the following categories of threats to each gas distribution pipeline:

(1) corrosion;
(2) natural forces;
(3) excavation damage;
(4) other outside force damage;
(5) material, weld or joint failure (including compression coupling);
(6) equipment failure;
(7) incorrect operation; and
(8) other concerns that could threaten the integrity of its pipeline.

An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) Evaluate and rank risk. An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. An operator may subdivide its pipeline into regions with similar characteristics (e.g., contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.

(d) Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures would include an effective leak management program as required by sections 255.805 through 255.821, unless all leaks are repaired when found.

(e) Measure performance, monitor results, and evaluate effectiveness.

(1) Develop and monitor performance measures from an established baseline to evaluate the effectiveness of its GDPIM program. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. These performance measures must include the following:

(i) Number of hazardous leaks either eliminated or repaired or total number of leaks if all leaks are repaired when found, categorized by cause;

(ii) Number of excavation damages;

(iii) Number of excavation tickets (receipt of information by the underground facility operator from the one-call notification center pursuant to Part 753 Protection of Underground Facilities, Subpart 753-5 One-Call Notification Systems of this Title);

(iv) Total number of leaks either eliminated or repaired, categorized by cause;

(v) Number of hazardous leaks either eliminated or repaired or total number of leaks if all leaks are repaired when found, categorized by material; and
(vi) Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's GDPIM program in controlling each identified threat.

(f) Periodic evaluation and improvement. An operator must reevaluate threats and risks on its entire pipeline and consider the relevance of threats in one location to other areas. Each operator must determine the appropriate period for conducting complete program evaluations based on the complexity of its system and changes in factors affecting the risk of failure. An operator must conduct a complete program re-evaluation at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(g) Report results. Report, on an annual basis, the four measures listed in paragraphs (e)(1)(i) through (e)(1)(iv) of this section, as part of the annual report required by 49 CFR Part 191.11.

255.1009 Required report when compression couplings fail.

(a) Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit a report on each mechanical fitting failure, excluding any failure that results only in a non-hazardous leak, on a Department of Transportation Form PHMSA F-7100.1-2. The report(s) must be submitted in accordance with 49 CFR 191.12.

(b) The mechanical fitting failure reporting requirements in paragraph (a) of this section do not apply to the following:
   (1) Small LPG operator as defined in section 255.1001; or
   (2) LNG facilities.

255.1011 Records an operator must keep.

An operator must maintain records demonstrating compliance with the requirements of sections 255.1003 through 255.1015 for at least 10 years. The records must include copies of superseded GDPIM plans developed under sections 255.1003 through 255.1015.

255.1013 Deviations from required periodic inspections.

(a) An operator may propose to reduce the frequency of periodic inspections and tests required in this Part on the basis of the engineering analysis and risk assessment required by this subpart.

(b) An operator must submit its proposal to the Public Service Commission as prescribed in sections 255.13(c). The Public Service Commission may accept the proposal on its own authority, with or without conditions and limitations, on a showing that the operator's proposal, which includes the adjusted interval, will provide an equal or greater overall level of safety.

(c) An operator may implement an approved reduction in the frequency of a periodic inspection or test only where the operator has developed and implemented an integrity management program that provides an equal or improved overall level of safety despite the reduced frequency of periodic inspections.

255.1015 Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan.

(a) General. No later than August 2, 2011 the operator of a small LPG operator must develop and implement an GDPIM program that includes a written GDPIM plan as specified in paragraph (b) of this section. The
GDPIM program for these pipelines should reflect the relative simplicity of these types of pipelines.

(b) Elements. A written GDPIM plan must address, at a minimum, the following elements:

1. Knowledge. The operator must demonstrate knowledge of its pipeline, which, to the extent known, should include the approximate location and material of its pipeline. The operator must identify additional information needed and provide a plan for gaining knowledge over time through normal activities conducted on the pipeline (for example, design, construction, operations or maintenance activities).
2. Identify threats. The operator must consider, at minimum, the following categories of threats (existing and potential): corrosion, natural forces, excavation damage, other outside force damage, material or weld failure, equipment failure, and incorrect operation.
3. Rank risks. The operator must evaluate the risks to its pipeline and estimate the relative importance of each identified threat.
4. Identity and implement measures to mitigate risks. The operator must determine and implement measures designed to reduce the risks from failure of its pipeline.
5. Measure performance, monitor results, and evaluate effectiveness. The operator must monitor, as a performance measure, the number of leaks eliminated or repaired on its pipeline and their causes.
6. Periodic evaluation and improvement. The operator must determine the appropriate period for conducting GDPIM program evaluations based on the complexity of its pipeline and changes in factors affecting the risk of failure. An operator must re-evaluate its entire GDPIM program at least every five years. The operator must consider the results of the performance monitoring in these evaluations.

(c) Records. The operator must maintain, for a period of at least 10 years, the following records:

1. A written GDPIM plan in accordance with this section, including superseded GDPIM plans;
2. Documents supporting threat identification; and
3. Documents showing the location and material of all piping and appurtenances that are installed after the effective date of the operator's GDPIM program and, to the extent known, the location and material of all pipe and appurtenances that were existing on the effective date of the operator's GDPIM program.

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