Operations and Maintenance Guidance
49 CFR 192 (Subparts L & M)

Introduction

The materials contained in this document consist of guidance, techniques, procedures and other information for internal use by the PHMSA pipeline safety enforcement staff. This guidance document describes the practices used by PHMSA pipeline safety investigators and other enforcement personnel in undertaking their compliance, inspection, and enforcement activities and is intended to be used solely as a reference by PHMSA personnel. This document is U.S. Government property and is to be used in conjunction with official duties.

The Federal pipeline safety regulations (49 CFR Parts 190-199) discussed in this guidance document contains legally binding requirements. This document is not a regulation and creates no new legal obligations. In the event of a conflict between this document and any regulation, the document would not be controlling. The materials in this document are explanatory in nature and reflect PHMSA's current application of the regulations in effect at the time of the issuance of the guidance to the implementation scenarios presented in the materials. Alternative approaches are not precluded if they satisfy the requirements of the applicable regulation(s).

Nothing in this guidance document is intended to diminish or otherwise affect the authority of PHMSA to carry out its statutory, regulatory or other official functions or to commit PHMSA to taking any action that is subject to its discretion. Nothing in this document is intended to and does not create any legal or equitable right or benefit, substantive or procedural, enforceable at law by any person or organization against PHMSA, its personnel, State agencies or officers carrying out programs authorized under Federal law.

Decisions about specific investigations and enforcement cases are made according to the specific facts and circumstances at hand. Investigations and compliance determinations often require careful legal and technical analysis of complicated issues. Although this guidance document serves as a reference for the staff responsible for investigations and enforcement, no set of procedures or policies can replace the need for active and ongoing consultation with supervisors and colleagues in enforcement matters.

Comments and suggestions for future changes and additions to this guidance document are invited and should be forwarded to your supervisor.

The materials in this guidance document may be modified or revoked without prior notice by PHMSA management.

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Term	Definition
Abandoned Pipeline	A pipeline that has been physically separated from its source of gas or hazardous liquid and is no longer maintained under regulation 49 CFR Parts 192 or 195, as applicable. Abandoned pipelines are usually purged of the gas or liquid and refilled with nitrogen, water, or a non-flammable slurry mixture. In 49 CFR Part 192 Abandoned means permanently removed from service.
Active Corrosion	Active corrosion describes an ongoing electro-chemical process whereby microscopic metal particles are removed from ferrous-based materials. Corrosion can occur in moist atmospheric conditions but is more prevalent in subterranean environments. Active corrosion within the pipeline industry is a serious threat to pressure containing structures that, unless controlled, could result in a condition that is detrimental to public safety.
Actual wall thickness	The measured wall thickness of pipe from its inner surface to its outer surface. This measured dimension must be within tolerances stated in the manufacturer's specification. Actual wall thickness of installed pipe can be determined by using an ultra-sonic thickness gauge (UT gauge).
Actuator	A component designed to provide the mechanical energy to physically move a connected device. In the oil and gas industry, actuators are used extensively to move valves to their open and closed positions. Mounted on top of the valve bodies, the actuators can be pneumatic, hydraulic, or electric motor driven. On larger valves, a gearbox is often employed to add the mechanical advantage of high torque. Such devices can be automated to shut off flow without a person being physically at the location. Valve actuators on mainline systems are primary operated by pushing a local control button or remotely commanded from a centralized control room.
Adhesive joint	A joint made on certain types of plastic piping by the use of an adhesive substance which forms a bond between the mating surfaces without dissolving either one of them.
Administrator	The Administrator of the Pipeline and Hazardous Materials Safety Administration or any person to whom authority in the matter concerned has been delegated by the Secretary of Transportation.
Aerial river crossing	Where a pipeline crosses over a river and is either suspended by cables over the waterway or attached to the girders of a bridge designed to carry vehicular traffic. In essence, a pipeline that crosses a river where the pipe is not submerged in the water, buried, or bored under the riverbed.
Alternating current (AC)	An electrical current whose direction or polarity changes with time. The polarity or cycles are due to the alternating magnetic fields used in its generation. The time frequency cycle is also referred to as hertz. In North America, the common frequency is 60 hertz (cycles per second). In other parts of the world, 50 hertz is common.

Term	Definition
Ambient temperature	The temperature of the surrounding air or environment. This thermal condition is often referenced to calculate how it might affect the design or operation of various devices on the pipeline.
Anhydrous ammonia	Under atmospheric conditions, anhydrous ammonia is a toxic colorless gas with a pungent-suffocating odor. It is normally shipped in a compressed liquid state and is considered to be a hazardous liquid by the Office of Pipeline Safety. It will burn skin if touched and can be deadly if inhaled.
Anode	The electrode in a corrosion cell where oxidation or corrosion occurs. In a pipeline-related cathodic protection system, the anode is designed as the sacrificial material installed to purposely corrode and protect the structure (pipeline, tank bottom, or other underground structure). There are two basic types of anodes: the galvanic type and the impressed current type.
Anodeless riser	An anodeless riser is a plastic pipe sheathed inside a protective steel metallic casing. The steel-cased plastic pipe protrudes from the soil and is part of the service line carrying gas to the customer meter. An anode is not required in this instance because the plastic pipe contains the gas pressure and is not susceptible to the typical corrosive processes.
Anomaly	Any kind of imperfection, or defect, or critical defect that may be present in the wall of the pipe. Anomalies can be caused by such acts as external impacts, manufacturing flaws, poor welds, or corrosion. An anomaly is usually detected by visual or non-destructive testing methods.
Backfilling	Backfilling is the technique for covering a newly constructed or recently unearthed pipeline so that adequate fill material is provided and compacted around the pipe to completely fill the excavation. Proper backfilling is critical so that the pipe is properly supported and not subjected to added stresses due to soil subsidence or movement.
Ball valve	A valve in which a solid metal sphere with a hole in the center rotates within the valve body to control the flow of fluids. The ball usually rotates within a set of sealing rings. The hole can be the same size as the pipe's internal diameter (referred to as full-ported) and thus allow for passage of pigs.
Barhole	A small diameter hole in the ground made by a plunger bar. These holes are made along the route of a gas pipeline to check the sub-surface soil for gas accumulations due to leaks.
Barlow's formula	A mathematical formula that calculates the pressure containing capabilities of pipe. As you can see, the formula takes into account the pipe diameter, wall thickness, and the manufacturer's specified minimum yield strength of the pipe. ($P=2St/D$)
Bell hole	An enlarged hole dug along the side of pipelines or in a trench to allow room for workmen to perform maintenance-related work on the pipeline (repairs, welding, or replacing pipe). In the broad sense, any hole, other than a ditch, opened for pipeline work.

Term	Definition
Blowdown	Blowdown refers to the depressurizing of a natural gas pipeline to facilitate maintenance on the pipeline, and is accomplished by opening a valve and allowing the gas to escape through a vertical pipe or "stack"
Boiling point	The temperature at which a liquid changes into a gas. For example, water at sea level boils at 212° F, whereas, the boiling point of natural gas is approximately -260° F. This characteristic helps determine under what conditions a hydrocarbon-based substance will vaporize or revert back to its liquid state.
Bottle	A gas tight structure completely fabricated from pipe with integral drawn, forged end caps and tested in the manufacturer's plant (per ASME guidelines). These pressure vessels are used to store gas under pressure. Individual bottles or group of interconnected bottles can be installed above ground or buried underground. These pressure containers are sometimes referred to as “bullets.”
Bottle-type holder	Any bottle or group of interconnected bottles buried underground installed in one location and used for the sole purpose of storing gas.
Branch service line	A service line that branches off of another service line; thereby changing the classification upstream of the branch point from a service line to a main.
British Thermal Unit (BTU)	The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit. BTU values of gas indicate the amount of heat a given unit of gas will provide. This BTU rating helps to compare the heating values of different gases and thus drives the market price.
Buckle	A partial collapse of the pipe wall due to excessive bending associated with soil instability, landslides, washouts, frost heaves, earthquakes, etc. Buckles can also occur in pipeline construction during a field bending operation using a side boom. Buckles cause localized stress concentrations and must not be installed in new construction or, if found, must be removed from existing systems.
Business district	A business district is not officially defined in the code CFR Part 192, but is based on this generally accepted interpretation letter issued by a former Director of the Office of Pipeline Safety: "A 'business district' is an area marked by a distinguishing characteristic of being used in the conducting of buying and selling commodities and service, and related transactions. A 'business district' would normally be associated with the assembly of people in shops, offices and the like in the conduct of such business. It is the responsibility of the operator to determine if an area is a 'business district'."
Butt fusion joint	A joining technique for polyethylene pipe and fittings consisting of heating the squared ends of matching surfaces by holding them against a heating plate until fusion temperature is reached, pushing the two softened ends against one another, holding them under pressure for the manufacturer's prescribed time, and allowing the joint to cool. Performed properly, a fusion joint becomes stronger than the pipe material.

Term	Definition
Bypass type odorizer	A device that adds an odorizing chemical to gas streams by diverting a portion of the main gas stream through a tank of the odorant. Once in the tank, the gas passes over baffles or wicks where the odorant is absorbed by the gas. The odorant-saturated gas is then returned to the mainstream. The bypass type of odorant system is generally used for low or more uniform flow-rate systems.
Carbon steel	By common custom, steel is considered to be carbon steel when (1) no minimum content is specified or required for aluminum, boron, chromium, cobalt, columbium, molybdenum, nickel, titanium, tungsten, vanadium, zirconium, or any other element added to obtain a desired alloying effect; (2) the specified minimum content does not exceed 1.65% for manganese or 0.60% for copper. All carbon steels may contain small quantities of unspecified residual elements unavoidably retained from raw materials. These elements (copper, nickel, molybdenum, chromium, etc.) are considered incidental and are not normally determined or reported.
Cast iron	Applies to gray cast iron which is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed through the metal. Because the carbon flakes do not bond with the ferrous material on the molecular level, the metal is brittle and susceptible to stress cracking under higher pressure situations. Many older low pressure gas systems use cast iron pipes since it was cheaper to produce than steel pipe.
Cathodic protection	Pipeline cathodic protection (CP) systems are designed to limit corrosion of steel pipe and other underground metallic structures. If left unprotected, the natural electrolytic conditions in the soil will cause small electrical currents to flow away from the pipe's surface, carrying with it, microscopic metal particles. Cathodic protection prevents metal particles from leaving the pipe's surface by forcing electrical current to flow toward the pipe, which opposes or cancels out any natural current attempting to leave the structure.
Centering	The process of approximating a leak location. Centering can be done manually using gas detection equipment, such as a combustible gas indicator (CGI); through more modern means such as using acoustical equipment; or through a more sophisticated SCADA-based leak detection system using mathematical modeling of critical pressures, temperatures, flow-rates, etc. to predict volume loss and location estimates.
Centrifugal compressor	Centrifugal compressors are used to boost the pressure of the gas at key locations on transmission pipeline system. Centrifugal compressors are typically used in higher flow applications and impart the rotational energy provided by their prime movers to the gas to move it along within the pipeline.

Term	Definition
Check valve	A valve which allows liquids or gases to pass in one direction, but closes to prevent reverse-flow or back-flow in the opposite direction. Check valves employ a flapper or split wafers that are spring-loaded or gravity-assisted to close upon reverse flow conditions.
Chiller	A chiller is generally a heat exchanger, designed to remove thermal energy or heat from a gas flow stream usually to prepare it for further compression.
Christmas tree	The stacking of control valves, pressure gauges, and chokes at the top of a well to control the flow of oil and gas after the well has been drilled and completed. The term christmas tree was used to describe the pyramid-like shape of the stacked components.
Cleaning pig	A utility pig that uses cups, scrapers, or brushes to remove dirt, paraffin, rust, mill scale, or other foreign matter from the inside of a pipeline. Cleaning pigs are run to increase the operating efficiency of a pipeline or to prepare the pipeline for an internal inspection.
Coalescence	The joining or fusing of metals produced by extreme temperatures achieved from an electrical arc between the metal electrode of a welding rod and the base metal of the pipe or other metallic structure. The welding machine produces the high electrical current and voltage necessary to get the arc to jump between the two metals.
Combustible Gas Indicator (CGI)	A device used to detect flammable gas concentrations. A 2 to 3 foot probe rod and hose assembly is normally attached to an electronic unit that draws in an air sample by squeezing a rubber bulb. A small portion of the sample is then subjected to either a catalytic filament (0% to 5% gas in air range) or a thermal conductivity filament (5% to 100% gas in air range). If the sample contains flammable gases in sufficient concentrations, an electrical signal will provide a meter reading (usually in percent of gas to air). The CGI should be used by properly trained field personnel to center, to pinpoint, to classify gas leaks, and to investigate any reports of gas odors within structures.
Combustion	The process of burning where a flammable substance is subjected to a heat source in the presence of oxygen. The degree of heat and the ratio of air to fuel will depend on the flammability characteristics of the substance.
Component	A component is considered any part of a pipeline that may be subjected to pump or compressor discharge pressure including, but not limited to, pipe, valves, fittings, flanges, and closures.
Compressed Natural Gas	Natural gas stored inside containers at a pressure greater than atmospheric air pressure. CNG is normally placed in pressure containing vessels (bottles) where it can be used as a portable fuel source (i.e., in CNG vehicles and other applications not attached to a pipeline).

Term	Definition
Compressor station	Any permanent combination of facilities which supplies the energy to move gas at increased pressure from production fields, in transmission lines, or into storage. Compressor stations are strategically placed along the pipeline to boost the pressure to maintain required flow rates. Typical components found at gas compressor stations include: piping manifolds, coolers, valves, reciprocating or centrifugal compressors, prime movers (electric motors, gas engines, gas turbines), and local controls and instrumentation.
Computational Pipeline Monitoring (CPM)	A software-based monitoring tool running in parallel with a pipeline SCADA system that alerts the dispatcher of a possible pipeline operating abnormality that may indicate a commodity release or leak.
Cracks	Cracks in line pipe are separations in the molecular structure of the base metal and form as a result of improper manufacturing or due to operational stresses. Cracks are obviously detrimental to the pipe's pressure restraining capabilities and can propagate into complete failure or rupture zones.
Critical bond	Buried pipelines in close proximity or crossing over/under one another will often have different levels of cathodic protection and thus a strong possibility of different electrical potentials (voltage differences). If the soil resistance path between the pipelines is low, electrical currents will flow off one pipeline and travel toward the other pipeline. The pipeline with the current leaving will experience metal loss or corrosion. To prevent this occurrence, pipeline companies electrically connect or bond their pipes to one another using a copper wire. The wire provides an electrical path for the current to flow through rather than allowing current to flow off the pipe and into the soil, thus eliminating corrosion. The connecting wire is referred to as an electrical bond. 'Critical bonds' are those that if not attached, would allow corrosion to occur and jeopardize the safe operation of one of the pipelines in question. Since they ensure the pipe's integrity, critical bonds must be inspected more often than non-critical bonds per Part 192.465c.
Curb valve	A valve installed for the purpose of shutting off the gas supply to a building. It is installed below grade in a service line at or near the property line and is operated by use of a removable key or specialized wrench. The valve is normally installed with a protective curb box or standpipe over or around it for quick subsurface access.
Current	The flow of electrons in a circuit. Current is usually measured in engineering units called amperes and indicates how much electrical energy is being consumed by an electrical device.
Customer meter	In 49 CFR Part 192 - the meter that measures the transfer of gas from an operator to a consumer.

Term	Definition
Customer regulator	A device that limits and maintains a set pressure to the customer. This pressure controlling device is normally installed just upstream of the customer meter. The community's distribution piping network will usually operate at slightly higher pressures than the end user requires. Residential systems are typically set for delivered pressure less than 1 psi. Commercial customers may have higher-pressure settings depending on their facility needs.
Deadman	An anchoring point against which the winch on a boring machine for pipelining can pull.
Defect	The term defect describes an imperfection in a pressure vessel or pipe that should be analyzed using a recognized and approved procedure, such as ASME B31G. Defects may be determined to be minor or severe and may need to be removed or fortified with a protective sleeve depending on prescribed operating requirements.
Dent	A local depression in the pipe surface caused by an outside mechanical force which does not reduce the pipe wall thickness. The inward depression, if severe enough, may affect the passage of internal pigging tools. Pipeline repairs or replacement may be needed depending on the amount of deformation
Destructive testing	A physical testing process (such as a burst or a tensile test) during which the specimen being-tested is rendered unusable. These tests are typically conducted to prove the strength or chemical characteristics of the sample piece.
Determine	In pipeline regulatory language, this means to establish or ascertain definitely after considering an investigation or calculation. This is critical in differentiating between "discovering" vs. "determining" with respect to required time frames with which to file a "safety-related condition" report to the Office of Pipeline Safety (191.25a).
Direct Current (DC)	The polarity or direction of DC current stays constant with respect to time. DC current is normally generated through an electrochemical process such as that of a battery system. The polarity, or positive to negative swings of alternating current can be converted to direct current by the use of a rectifier. DC current is typically used in impressed current cathodic protection systems because of its ability to maintain a constant polarity for the pipe's protection.
Direct sales lateral	A pipeline that transports gas to a large volume customer: such as a factory or power plant. This pipeline is connected upstream from a distribution center or directly off of a transmission line.
Discovery	To gain knowledge of something through: observation, study, or research. To be the first to find, learn, or observe. The definition of "discovery" is critical from a regulatory standpoint in meeting deadlines for filing safety-related condition reports to the Associate Administrator of the Office of Pipeline Safety (per 191.25a).
Distribution line	In 49 CFR Part 192 - a pipeline other than a gathering or transmission line.
Double Submerged Arc Weld (DSAW)	A pipe having longitudinal or spiral seams produced by at least two weld passes, including at least one each on the inside and outside of the pipe. The molten metal is shielded by a blanket of granular, fusible material use to reduce the impurities (slag) introduced from the surrounding air. Pressure is not used and filler metal for the inside and outside welds is obtained from the electrode(s).
Drip type	Equipment for introducing odorant from a storage tank directly into a gas stream

odorizer	through a gravity flow system. The odorant may be regulated by the orifice float valves or rotameters. Since gas in its natural state is odorless, aromatic chemicals are added to the gas to aid in detecting leaks.
Ductile (nodular) iron	A cast ferrous material in which the free graphite (carbon) present is in a spherical form rather than a flake form as in cast iron. These round shaped carbon elements cause ductile iron to be more malleable than cast iron, yet retain its toughness. These desirable properties of ductile iron are achieved by means of chemistry and a specialized heat treatment of the castings.
Elbow (ELL)	A pipe fitting that makes an angle in a pipe run. Unless stated otherwise, the angle is usually assumed to be 90°. In larger pipelines, fitting type elbows may not be recommended due to their abrupt change in direction. Consideration should be given to running internal cleaning and inspection devices (also known as pigs). Piggable lines should be equipped with gradual bends of twice the pipe diameter or more.
Electric flash welded pipe	Pipe having a longitudinal butt joint wherein coalescence is produced, simultaneously over the entire area of butting surfaces, by the heat obtained from resistance to the flow of electric current between the two surfaces, and by the application of pressure after heating is substantially completed. Flashing and upsetting are accompanied by the expulsion of metal from the joint.
Electric fusion welded pipe	Pipe having a longitudinal butt joint wherein coalescence is produced in the preformed tube by manual or automatic electric-arc welding. The weld may be single or double and may be made with or without the use of filler metal.
Electric resistance welded (ERW) pipe	Pipe which has a longitudinal butt joint wherein coalescence is produced by the application of pressure and by the heat obtained from the resistance of the pipe to the flow of an electric current in a circuit of which the pipe is a part.
Emergency response personnel	Any persons engaged in the response to hazardous materials emergency, including firefighters, police, civil defense/emergency management officials, sheriffs, military, and manufacturing and transportation personnel. In large emergencies, an Incident Command System (ICS) is usually established. This is an emergency management system whereby key decisions are made by a Unified Command group consisting of representatives of both the Federal and State Government, and the Responsible Party (in pipeline related events this would be the operator).
Explosive	Chemical material that can undergo a sudden and violent release of pressure and heat. This is extremely harmful to the surrounding environment as well as livestock and humans since the explosion is customarily associated with a tremendous outward moving pressure shock wave and very high temperatures due to the chemical reactions taking place.
Exposed Underwater Pipeline	In 49 CFR Part 192 - an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

Term	Definition
Flame Ionization	The flame ionization detector is used as a leakage detection instrument for surface surveys. It indicates the presence of natural gas or other hydrocarbons in parts per million (PPM). Sample vapors are drawn in and subjected to a high temperature filament where the gases are ionized into atoms. Once ionized, the hydrocarbon atoms are totaled and a proportional electric current drives the onboard meter to indicate the concentration of combustible gases. The FI detector has been known to be affected by ambient temperatures below 40°F, high humidity conditions, and oxygen deficient areas.
Flammable	A substance that will burn readily or quickly. OSHA defines flammable substances as those materials that have the ability to generate ignitable vapors (also referred to as its flash point) with temperatures at or below 100°F.
Flammable (explosive) limit	The range of a gas or vapor concentration that will burn or explode if an ignition source is introduced. Limiting concentrations are commonly called the “lower explosive or flammable limit” (LEL/LFL) and the “upper explosive or flammable limit” (UEL/UFL). Below the explosive or flammable limit the mixture is too lean to burn and above the upper explosive or flammable limit the mixture is too rich to burn. Caution must be exercised when viewing LEL/UEL readouts on gas sensing instruments.
Furnace lap welded pipe	Pipe which has a longitudinal lap joint that is produced by the forge welding process. In this process, coalescence is produced by heating preformed tube to welding temperature and then passing it over a mandrel. The mandrel is located between the two welding rolls that compress and weld the overlapping edges. The longitudinal seam of furnace-welded pipe is not considered as strong as other production processes and therefore becomes a limiting factor in the design formula for steel pipe (refer to Part 192.113).
Fusion	A process of joining plastic pipe segments by melting the plastic polymers at the two ends with heat to an extent where they will molecularly bond when pressed together. Depending on the type and size of pipe and the fusion machine used, precise temperatures, pressures, and time of cooling prior to releasing the joint from the fusion machine are all critical to producing an acceptable joint.
Gas	In terms of the pipeline safety regulation 49 CFR Part 192, gas is considered natural gas, flammable gas, or gas which is toxic or corrosive. In general, gas usually refers to the vapor state of a substance. Gases are normally compared to air in terms of its density. Since the specific gravity of air is 1.0 any gas with a specific gravity less than 1.0 will rise, and anything greater than 1.0 will fall and collect near the ground or in low lying areas such as trenches, vaults, ditching ditches, and bell holes.
Galvanic series	A list of metals and alloys arranged according to their relative electrolytic potentials

Term	Definition
	to one another in a given environment. The metals or alloys higher on the list (more negative) are anodic to those lower on the list, and the metals or alloys lower on the list (more positive) are cathodic to those higher on the list.

Metal/Alloy Classification	Potentials (VOLTS)	General
Commercially pure magnesium		
Magnesium alloy (6% A1, 3% Zn, 0.15% Mn)	-1.75	Anodic
Zinc	-1.1	
Aluminum alloy (5% zinc)	-1.05	
Commercially pure aluminum	-0.8	
Mild steel (clean and shiny)	-0.5 to -0.8	
Mild steel (rusted)	-0.2 to -0.5	
Cast iron (not graphitized)	-0.5	
Lead	-0.5	
Mild steel in concrete	-0.2	
Copper, brass, bronze	-0.2	
High silicon cast iron	-0.2	
Mill scale on steel	-0.2	
Carbon, graphite, coke	+0.3	Cathodic

Term	Definition
Galvanic type anode	A galvanic type of anode is sacrificial material used to prevent metal structures from corroding. These anodes are made of materials with a relatively low electrolytic potential and thus will allow electrical currents to flow off themselves and toward the protected metal, usually a subsurface pipeline or other buried steel component such as a tank bottom in direct contact with the soil.
Gate station	A location at which gas may change ownership from one party to another (e.g., from a transmission company to a local distribution company), neither of which is the ultimate consumer. In this instance, the gas is purchased for the sole purpose of resale. A gate station is also referred to as city gate station or town border station.
Gate valve	A gate valve is a mechanical device designed to open or close the flow pathway within a pipe or piping system. A thick slab of metal with a hole in the bottom half slides between two sealing elements. When the slab is in the upper position, the hole aligns with the valve body ports and allows flow. The slab is positioned by a metal rod called a stem. The stem connects to the top of the slab and rides within a stem seal assembly. The rod is threaded at the top and is operated by either a hand wheel or a mechanical actuator. The valve bodies can either be round or rectangular. Depending on the piping installation, valves can be positioned above or below ground.

Term	Definition
Gathering line	In 49 CFR Part 192, a gathering line is a pipeline that transports gas from a current production facility to a transmission line or main.
General corrosion	A form of metallic deterioration of steel pipe that is distributed uniformly over the surface.
Geophone	A geophone is an acoustical monitoring device that is used to magnify sounds in and around pipelines. Geophones are typically used to monitor the passage of pipeline pigs or to detect leaks.
Girth weld	A complete circumferential weld joining pipe end-to-end, also called a butt weld. An actual girth weld is usually made up of a number of weld passes beginning with the root pass or stringer bead and completed with the cap pass.
Globe valve	A globe valve is internally equipped with a flat or conical plug attached to a stem that blocks flow when it is seated in a circular orifice. The body of valve is normally spherical in shape with a lateral incoming flow-path being directed vertically through the closure seat then exiting again laterally. This radical change in flow-path causes the characteristic attribute of a comparatively large pressure drop across this type of valve. Throttling or total shut-off is obtained by adjusting the plug downward against the flow-path toward the mating seat.
Ground temperature	The temperature of the earth at pipe depth. The temperature of the soil directly around the pipe is often affected by sub-freezing ambient temperatures
Half-cell (electrode)	A hand-held device consisting of a copper rod immersed in a copper sulfate solution. When connected to a voltmeter, it is used to measure the voltage potential between the metallic surface of the pipe and the soil or seawater (electrolyte) with respect to that of the junction of the copper rod and the copper sulfate solution within the half-cell probe. The voltage potential or difference will indicate the level of cathodic protection on the pipe. These readings, often called pipe-to-soil readings, are required to be taken at intervals prescribed in Part 192.465 or 195.416.
Hazard to navigation	In 49 CFR Part 192 – this means a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.
Heat fusion joint	A joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when the parts are pressed together.
High pressure distribution system	In 49 CFR Part 192 this means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer. By strict definition, even system pressures as low as 2 psi could be considered "high pressure distribution systems" due to employing a customer regulator to reduce mainline pressure down to delivered pressure.
Holiday	A discontinuity or break in the anti-corrosion coating on pipe or tubing that leaves the bare metal exposed to corrosive processes. Holidays are located by an electrical device called a “holiday detector” or "jeep."
Hoop stress (Barlow’s	The stress in a pipe wall acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe and produced by the pressure of the fluid or gas in the

Term	Definition
formula)	pipe. Hoop stress is a very critical factor in determining a pipe's pressure holding capabilities and thus its appropriate application.
Hot pass	The second pass made on a weld. The hot pass immediately follows the root, or stringer bead pass and precedes the filler passes and cap weld.
Hot tap	The process of making branch piping connections to operating pipelines, mains, or other facilities while in operation. The connection of the branch piping to the operating line and the tapping of the operating line is done while it is under pressure. A split tee saddle is permanently welded to the carrier pipe. A full-ported gate valve is normally bolted onto the tee fitting. Next, a special pressure containing hole cutter or tapping machine is bolted to this valve. The valve is positioned to its full open position, the tapping machine is started, and its cutting bit is slowly lowered to the pipe surface. The portion of the pipe that is cut out is called a coupon and is retracted out of the hole along with the cutter bit. The valve is now closed and the cutting machine relieved of the line pressure. The tapping machine is removed and the valve is now ready for the branch connection piping to be bolted up to the valve's flange.
Housekeeping	The administrative control that involves containing and removing chemical hazards, (e.g., vacuuming, proper storage and handling, prompt removal and correct disposal of chemical waste). In general terms, it refers to keeping a worksite free of debris and hazards that could contribute to accidents.
Hydrocarbon (H.C.) filter	A filtering element used to separate out heavier hydrocarbons when using a combustible gas indicator (CGI). Gasoline, propane, butane and commercial solvents are good examples of heavier hydrocarbons that should be filtered in order to detect only the lighter methane and ethane that would indicate a natural gas leak from a pipeline.
Hydrostatic testing	Hydrostatic testing is the most common quality control check of the structural integrity of a pipeline. In this test, the line is filled with a liquid, usually water, and then a specified pressure is applied and maintained for a specific period of time; any ruptures or leaks revealed by the test must be properly repaired.
Ignition temperature	The minimum temperature required to ignite gas or vapor without a spark or flame being present.
Impressed current anode	Impressed-current cathodic protection systems bury anodes typically made of graphite or high-silicon cast iron in deep wells drilled along the pipeline route. The anodes are then covered or backfilled with a low electrical resistant material called coke breeze that helps conduct the DC current from the anode. These anodes or ground beds as they are often referred to, are electrically connected to a rectifier that converts commercial AC power to DC current. This DC current is then "force fed" into the surrounding soil to protect the pipe from harmful corrosion.
Inactive pipeline	A pipeline that is being maintained under Part 192 or 195 but is not presently being used to transport gas or liquids. Inactive lines will not need specialized testing (for example, hydro testing, smart pigging, etc.) prior to reactivating them back into service.

Term	Definition
Inert gas	This is commonly referred to as a gas that is non-explosive (non-flammable). The most commonly used inert gas is nitrogen. Operators use inert gases for testing and purging pipelines. Nitrogen is often used to blanket an area or fuel source to keep it from contacting ambient air which contains the oxygen needed for combustion. Be aware that a high concentration of nitrogen is hazardous to animals and humans since it displaces breathable air.
Injector type odorizer	A pump-type odorizer. The flow rate of the gas stream is monitored by an electronic sensor which, in turn, controls the odorant pump injection rate.
In-patient hospitalization	Admission and confinement in a hospital, beyond treatment administered in an emergency room or outpatient clinic in which confinement does not occur. This definition is critical in that it is one of the key factors in determining if an incident or accident is reportable to the Office of Pipeline Safety, under 49 CFR Parts 191 and 192.
Instrument piping	Pipe, valves and fittings used to connect instruments to main piping, to other instruments and apparatus, or to measuring equipment. Instrument piping or tubing can be direct, meaning the process gas or liquid being measured is in direct contact with the instrument. Indirect piping or tubing may contain intermediary gases or liquids that prevent debris or other harmful substances from damaging or plugging the instrument but still can relay the measured parameter (for example, when a capillary tube filled with glycerin is used to relay pressure status to a pressure transmitter).
Internal night cap	A plug or cap attached to the open end of a pipe or pipeline to keep foreign objects or matter out of the pipe. These "night caps" are often used on construction or repair jobs and are usually installed at the end of a workday or shift.
Jeep	A portable device for inspecting pipe coating which uses a spring-like coil of wire that surrounds the coated pipe. Another wire leads from its on-board self-contained power source to induce a small electrical charge in the pipe. When the coil passes over a hole or tear in the coating, an electrical circuit is formed and an audible beeping is heard to alert the operator of the break in the coating. The audible beep is what gives the instrument the name "jeep."
Joint	Refers to the connection between two lengths of pipe such as the weld joint for steel pipe and the heat fusion or glue joint for plastic pipe. Joint is also used as a slang term meaning a length of pipe (i.e., joint of pipe).
Large volume customer	A customer who receives similar volumes of gas as a distribution center. This may include factories, power plants and institutional users. Since many pipeline facilities use gas to power some of the on-site equipment, this classification should be negotiated with the Office of Pipeline Safety to determine if the fuel lines are DOT jurisdictional.
Leak classification	Leak classification is determined by the operator and is based on experience and/or industry practices. Typically, a leak is classified based on an evaluation of the location and/or extent of a leak. Leaks and repair prioritization is determined by a ranking system. Leaks can be ranked as a class or grade A, B, C, or 1, 2, 3, or as a combination of alphabet and numbers, and usually are. The following leak grades/classes are examples that can be assigned, thereby establishing the leak repair

Term	Definition
	priority. **Grade 1:** a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous (for example, a leak that is at a building wall or inside a building). **Grade 2:** a leak that is recognized as being non-hazardous at the time of detection, but, requires scheduled repair based on probable future hazard (such as, a leak under frozen or other adverse soil conditions that would likely migrate to the outside wall of a building). **Grade 3:** a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous (for example, a leak under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside of a building).
Leakage survey	A systematic inspection using gas detection instruments for the purpose of finding leaks on a gas piping system. Depending on if the gas is odorized or not, the class location designation, and whether the piping is considered transmission or distribution will affect the required frequency of the inspections. Refer to Parts 192.706 (transmission) or 192.723 (distribution) for other specifics regarding leakage surveys.
Length	A piece of pipe as delivered from the mill. Each piece is called a length regardless of its actual dimension however, 40 feet is typical for larger diameter pipe. While this is sometimes called "joint," the term "length" is preferred.
Line section	In 49 CFR Part 192 this means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.
Liquefied Natural Gas (LNG)	Natural gas or synthetic gas having methane (CH_4) as its major constituent which has been changed to a liquid or semisolid either by increasing its pressure or by lowering its temperature.
Liquefied Petroleum Gas (LPG)	A gas containing certain specific hydrocarbons which are gaseous under normal atmospheric conditions, but can be liquefied under moderate pressure at normal temperatures. Propane and butane are principal examples.
Liquefied Petroleum Gas (LPG) air mixture	Liquefied petroleum gases distributed at relatively low pressures and normal atmospheric temperatures which have been diluted with air to produce desired heating value and utilization characteristics.
Listed specification	In 49 CFR Part 192 this means a specification listed in section I of Appendix B of this Part 192.

Term	Definition
Local Distribution Company (LDC)	An LDC is a local gas company responsible for distributing gas to its customers. An LDC purchases gas from transmission companies for resale to the consumer. LDC's operate and maintain the underground network piping, regulators, and meters that connect to each residential and commercial customer. Officially, the distribution company is responsible for the gas and piping up to the customer's meter, but will make service calls inside residential or commercial buildings for gas-related problems up to the "burner tip" if necessary.
Lock up or lock off	The point at which a regulator shuts off completely. This feature on a regulator is important so that, under no-flow conditions, the regulator does not seep gas downstream, which could create hazardous downstream conditions.
Long term hydrostatic strength (of plastic pipe)	The estimated hoop stress of thermoplastic pipe, in psi, which would result in a failure of the pipe if it were subjected to 100,000 hours of hydrostatic pressure. These estimated values are generated by the manufacturer through laboratory testing. The LTHS strength estimate (usually expressed as "S") is a key factor used in calculating the design pressure of plastic pipe.
Local pressure distribution system	A distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer. This is restricted to residential and small commercial service only. From a regulatory viewpoint, if the system has a pressure regulator, then it is considered a high pressure system regardless of how low the pressure is in the system. Conversely, a low pressure system is defined as a system without any regulators needed between the supplier and the customer.
Low-pressure distribution system	In 49 CFR Part 192 this means distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer. This is restricted to residential and small commercial service only. From a regulatory viewpoint, if the system has a pressure regulator, then it is considered a high pressure system regardless of how low the pressure is in the system. Conversely, a low pressure system is defined as a system without any regulators needed between the supplier and the customer.
Lower explosive limit (LEL)	Lower explosive limit is read from a CGI or other air monitoring instrument. LEL is the minimum amount of airborne chemical that must be present in the air-chemical mixture to make it explosive. Caution must be exercised when viewing LEL and upper explosive limit (UEL) readouts on gas sensing instruments. Some instruments readout in percent of LEL/UEL and some in percent of gas concentrations in air. Always refer to the detector's instruction manual to be sure you understand the scale being used by on the instrument.
Magnesium anode	Anodes made of magnesium are used in galvanic-type cathodic protection systems to protect underground steel pipe and other metallic structures from being corroded by the electrolytic forces occurring in most soils. Magnesium has a higher naturally occurring electromotive force or potential as compared to the steel of the pipe. Because of this characteristic, the magnesium creates a small electrical current that flows from it to the steel pipe and thus protects the pipe from corroding
Main	In 49 CFR Part 192 this means a distribution line that serves as a common source of supply for more than one service line.

Term	Definition
Mainline valves	Valves strategically positioned at locations along the pipeline system that can be closed down to isolate a line section in an emergency. Mainline valves are especially important to minimize hazards and damage or pollution from an accidental hazardous liquid discharge or from a major gas leak. Criteria that should be considered in their placement include: nearby population densities, proximity to unusually sensitive areas, distance from upstream and downstream stations, etc.
Manometer	A tube in the shape of a U, partially filled with liquid of suitable density. When sources of different pressure are connected to each end of the manometer, the liquid is pushed up in the low-pressure side of the manometer, and the difference in liquid level between the two sides of the U is an indication of pressure difference.
Master meter	A pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as including its cost within the monthly rent collected.
Maximum Actual Operating Pressure (MOP)	In 49 CFR Part this means the maximum pressure that occurs during normal operations over a period of 1 year. Could be momentary or could be sustained pressure.
Maximum Allowable Hoop Stress	The maximum hoop stress permitted for the design of a piping system. It depends upon the material used, the location of the pipe and the operating conditions.
Maximum Allowable Operating Pressure (MAOP)	In 49 CFR Part 192 this means the maximum pressure at which a pipeline osegment of a pipeline may be operated under Part 192. See §192.619 for further guidance.
Maximum Allowable Test Pressure	The maximum internal fluid pressure permitted for testing pipe. The calculations will be dependant upon: (1) the testing media (water, natural gas, inert gas, etc.), (2) the pipe materials (steel, plastic, etc.), (3) the intended working pressures (as a % of SMYS), and (4) the locations involved (class locations and proximity to buildings). See: Parts "192. 501 thru 192.517."
MCF	A measurement term used to indicate one thousand cubic feet of gas. 10 MCF then would represent 10,000 cubic feet of gas.
Mercaptan	An organic chemical compound having a very strong and distinctive odor used for odorization of gas streams. Since natural gas is odorless, mercaptan is added to the gas so that people can smell

Term	Definition
	escaping or leaking gas and report to the gas companies for further investigation
Meter set assembly	The piping installed to connect the inlet side of the meter to the gas service line, and to connect the outlet side of the meter to the customer's fuel line. An assembly consisting of the customer meter and the piping installed to connect the inlet side of the meter to the gas service line, and the piping to connect the outlet side of the meter to the customer's fuel line.
Meter	A meter is a mechanical device used to measure the volume throughput of natural gas or petroleum liquids. The internal construction varies depending on meter type and manufacturer. Some meters require a volumetric displacement of material and others depend on pressure differentials across a known orifice size. The primary purpose of a meter is to measure and record the throughput of the gas or liquid to determine consumption and thus is an essential device to provide the basis for billing calculation.
Methane	The lightest in the paraffin series of hydrocarbons (CH_4). It is colorless, odorless and flammable, and forms the major portion of natural gas. It is also lighter than air and will rise if released from containment.
Miter joint	A joint made by cutting the pipe at an angle, then joining them together. 49 CFR Part 192.233 provides guidelines for miter joints in steel pipelines. Miter joints are not allowed in plastic pipelines.
MMCF	A measurement term used to indicate one million cubic feet of gas. 22 MMCF then would represent 22,000,000 cubic feet of gas.
Monitoring regulators	A pressure regulator set in series with another pressure regulator, for the purpose of providing automatic overpressure protection in the event of a malfunction of the primary regulator. These backup regulator systems can be assembled in a variety of arrangements. Monitoring regulators are typically set at a control pressure slightly higher than the primary regulators.
Municipality	In 49 CFR Part 192 this means a city, county, or any other political subdivision of a state.
Natural Gas Liquids	Heavy hydrocarbons found in natural gas, which may be extracted or isolated and processed as liquefied petroleum gas (LPG) (examples include: propane, butane, and natural gasoline).
Needle Valve	A small valve used to regulate small amounts of gas or fluid flow. It contains a pointed plug or needle resting in an orifice or tapered orifice in the valve body. By adjusting the needle's position within the seat or orifice, small amounts of gas or liquids are finely regulated. Needle valves are typically used on instrument, control, or sampling pipe.
Nominal wall thickness	The manufacture's stated wall thickness of their pipe. The pipe's wall thickness (in inches) is used in the design formula for steel pipe (Ref. Parts 192.105 or 195.106). Pipe may be ordered to this computed wall thickness without adding an allowance to compensate for the under-thickness tolerances permitted in approved specifications. The wall thickness dimension is a major factor in calculating the pipe's pressure holding capabilities.
Non active corrosion	Corrosion that has been discovered and treated (coated, chemically inhibited, or otherwise controlled) to stop the metal particle loss on the walls of pressure

Term	Definition
	containing structures. These discovered and treated corrosion areas are often monitored over time to verify the corrosion process is in fact halted.
Non destructive testing (NDT)	Testing in which the part being tested is not rendered unusable. In pipeline related NDT testing, the pipe, its welds, or even steel components and tanks may need to be evaluated to verify their integrity. Pipeline NDT typically consists of: **1. Radiography (X-rays):** identifies laminationand weld discontinuities. **2. Ultrasonic:** locates lamination in the walls of pipe; determines wall thicknesses. **3. Magnetic particle inspection:** tests for surface cracks in welds and component bodies. **4. Dye penetrant:** locates surface cracks in welds or component bodies. **5. Ammonium persulfate:** identifies hard spots in welds due to arc burns.
Odorant	An odorant is a chemical substance added to natural gas so that the odor can be used as a warning sign of the presence of escaping gas. Governmental regulations require readily perceptible concentrations in gas of at least 20% or 1/5th of the lower explosive limit (LEL) of the gas. The odorant must be added to all distribution system gas as well as some transmission line gas. Refer to Part 192.625 for possible exemptions for transmission lines.
Odorizer	An odorizer is a piece of equipment that adds chemical odorant to flowing natural gas pipelines. Depending on the design of the odorizer, it may use a wick to pickup the chemical, a drip system to disperse the chemical into to the gas flow or an injector type device may spray the chemical into the flow stream.
Offshore	In 49 CFR Part 192 this means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.
Operating stress	The stress imposed on a pipe or structural member under operating conditions. This term normally refers to the internal forces due to the pressure of the gas or liquid in the pipeline; however, any other forces such as thermal growth, expansion, or contraction may need to be considered as well.
Operator	In 49 CFR Part 192 this means a person who engages in the transportation of gas.
Overpressure protection	The use of a device or equipment installed for the purpose of preventing pressure in a pipe system or other facility from exceeding a predetermined limit.
Parallel encroachment	Parallel encroachment describes that portion of the route of a pipeline system or main which lies within, or runs in a generally parallel direction, with the rights-of-way of a road, street, highway or railroad.

Term	Definition
Parts per million	Parts per million is a very precise unit typically used to express chemical concentration limits. PPM figures are often found in Occupational Health and Safety Administration (OHSA) guidelines to describe permissible exposure limits of harmful substances. The term actually refers to the parts of the chemical in each one million (1,000,000) parts of the base material - usually air or water.
Peak shaving	Peak shaving within the gas industry is the process of supplying additional gas volumes to supplement the throughput supply of pipeline gas during periods of extremely high demand. The use of LNG, or drawing reserves out of underground storage and pipeline vessels are good examples of how gas companies can meet peak demand volumes.
Performance language	Performance language is used by the Department of Transportation as a rulemaking approach that prescribes an end result (i.e., a certain level of pipeline safety) but leaves the method or how to achieve it up to the operator's discretion. As long as the end result meets the intent of the regulation, the operator is free to implement the task in a manner that best suits their operation. This approach is often used to allow each operator to accommodate their individual differences in equipment, procedures, and operational circumstances.
Person	In 49 CFR Part 192 this 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.
Personal protective equipment	Personal protective equipment, often referred to as PPE, describes equipment that protects the individual who wears it by placing a barrier between that individual and a potential or known hazard. Examples of PPE include protective eyewear, face shields, masks, gloves, boots, hats, clothing, and respirators.
Petroleum	The term petroleum refers to crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.
Petroleum Gas	In 49 CFR Part 192 this means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) at 100°F (38°C).
pH	pH is a 14-point scale that measures the acidic or alkalinity value of a substance. The measurement of the hydrogen ion concentrations in solution is called the pH; strong acids have low pH values and strong bases have high pH values. With a value of 7 being considered neutral, anything less than 7 is considered an acid and greater than 7 are alkaline or bases.

Term	Definition
Pig	A pig is a device used to clean and/or inspect the internal surface of a pipeline. Pigs are used to remove debris buildup such as paraffin to increase throughput (increase flow) and to remove harmful corrosive substances that can collect on the pipe's inner surfaces. Pigs can be barrel-shaped and made of dense foam or spool-shaped with a metal core having durable rubber or plastic cups installed. Some cleaning pigs can be outfitted with wire brushes to scour the inner pipe walls. Pigs are inserted into the pipeline by means of a device called a pig-trap and pushed through pipeline by pressure of flowing fluid or gas. The forward movement of the pig, together with its rotation, cleans the rust, deposited solids, liquids and other undesired substances from the pipeline. Pigs got their name from the occasional squealing noises heard as they travel through the pipe. Also called a go-devil.
Pinpointing	Pinpointing is the process of locating the exact source of a gas leak along a pipeline route with a minimum of excavation. This is accomplished using a gas measuring analyzer and a non-sparking metal plunger bar to punch holes in the ground along the pipeline's right-of-way.
Pipe	In 49 CFR Part 192 this means any pipe or tubing used in the transportation of gas, including pipe-type holders.
Pipe container	A gas-tight structure assembled from pipe with welded on end closures. These containers are often used for storage of pressurized gases or liquids.
Pipe-supporting element	A pipe-supporting element consists of fixtures and structural attachments.
Pipe-type holder	A pipe-type holder is a container or group of interconnected pipe containers installed at one location and used for the sole purpose of storing gas.
Pipeline	In 49 CFR Part 192 this means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies
Pipeline facility	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.
Pitting	Pitting describes the metal loss causing the formation of small depressions in a metallic surface due to sand blasting, mechanical gouging, acid etching, or corrosion. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion.
Pitot tube	A pitot tube is a small device that can be inserted into a pipe to measure the flow of liquid or gas. This device is composed of two tubes arranged in such a manner that will allow the measurement of both the velocity and static pressures of the flowing liquid or gas. The difference in these pressures is a function of the flow within the pipe.
Plastic	A material which contains, as an essential ingredient, an organic substance of high molecular weight. It is solid in its finished state and, at some stage of its manufacture or processing, was shaped or molded.

Term	Definition
Plastic pipe joints	Plastic pipe joints are locations in plastic pipe where another length of pipe has been joined to increase its length, change direction (such as an elbow) or attach another component or branch to the system.
Plug valve	A plug valve is a quarter turn metal valve in which a pierced plug rotates in a tapered or cylindrical body to control flow through the valve. Plug valves are normally used in quick open or closed applications but sometimes can be used for throttling purposes.
Plunger bar	A device used to punch holes in the soil along the route of a gas pipe when searching for gas leaks. Once the hole is formed, a gas sniffer is used to analyze if any gas is detected coming from the hole. It is also called a "probe bar."
Polyethylene pipe	Polyethylene pipe is a made of a thermoplastic material. The polyethylene material can be molded or extruded into sections of pipe or coiled tubing in varying lengths and diameters as well as angled and multiple-port fittings. Polyethylene pipe or tubing is normally abbreviated with the designation of PE and is joined by fusing the components under high heat and pressure. This piping or tubing material is quite common in the gas industry, particularly in the newer underground distribution networks around the country. Polyethylene pipe comes in varying densities that affect its pressure containing qualities. The yellow colored PE pipe is the medium-density and the black colored pipe is the high-density polyethylene material. Be sure to check the code stamped on the outside of the pipe to determine it specifies the base material and performance characteristics.
Pounds per square inch (PSI)	Pounds per square inch, often referred to as psi is the unit of pressure or measure of force on a given area. Within the oil and gas industry, psi normally refers to the pressure of the gas or product contained within the pipeline or pressure vessel.
Pounds per square inch absolute (PSIA)	Pounds per square inch absolute is the measure of force on a given area. The absolute refers to the total pressure sensed including the surrounding atmospheric pressure, if any. PSIA measurements are more precise since they can indicate a positive pressure above atmospheric as well as a vacuum condition if readings are less than the atmospheric pressure.
Pounds per square inch gauge (PSIG)	Pounds per square inch gauge refers to the pressure expressed in pounds exerted on one square inch of surface area. The designation “Gauge” indicates the readings are already adjusted or biased to ignore the surrounding atmospheric pressure which is 14.7 psi at sea level. If a PSIG type of gauge were not connected to any pressure source it would read zero even though it is actually sensing 14.7 psi at sea level.
Pressure	Pressure is the force on a given area expressed in pounds per square inch (PSI) or its metric equivalent of kilo Pascal’s (kPa). Pressure readings within the oil and gas industry normally indicate the amount of force the compressed or packed molecules have on the container holding them.

Term	Definition
Pressure limiting station	A pressure limiting station consists of a collection of pressure regulating valves, control instruments, control lines, and ventilating equipment. Under abnormal conditions, a pressure limiting station will act to reduce, restrict, or shut off the supply of gas flowing into a transmission line, main, holder, pressure vessel or compressor station piping in order to prevent the pressure from exceeding a predetermined limit. While normal pressure conditions prevail, the pressure limiting station may exercise some degree of control of the flow of gas or may remain in the wide-open position.
Pressure regulating station	A pressure regulating station consists of equipment installed for the purpose of automatically reducing and regulating the gas pressure in the downstream transmission line, main, holder, pressure vessel, or compressor station piping to which it is connected. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment (such as valves, control instruments or control lines).
Pressure relief station	A pressure relief station consists of equipment installed to vent excess gas from a transmission line, main, holder, pressure vessel, or compressor station piping in order to prevent the gas pressure from exceeding a predetermined limit. The gas may be vented into the atmosphere or into a lower pressure gas system capable of safely receiving the gas being discharged. Included in the pressure relief station are any enclosures and ventilating equipment, and any piping and auxiliary equipment (such as valves, control instruments or control lines).
Private right-of-way	Private right-of-way is a land use grant obtained through negotiations between the private landowner and the pipeline company. The land use grant permits the pipeline operator to install and maintain the pipeline buried within or traversing over private property.
Producing well	An underground well that produces oil or natural gas.
Proprietary items	Proprietary Items are products or services made or provided by a company having the exclusive right of design, manufacture, and marketing. Proprietary items are often legally protected from infringement by patents and/or copyrights.
Purging	Purging is the act of replacing oxygen or fuel-laden atmosphere within a container with an inert substance in such a manner as to prevent the formation of explosive mixtures. Commonly used inert substances include: Nitrogen (N) or Carbon Dioxide (CO_2). Purging can also have the opposite effect by replacing the inert substance with natural gas or hazardous liquid before putting the pipeline back into service.
Qualified welder	A qualified welder is a welder who has demonstrated the ability to produce sound welds meeting the requirements of 49 CFR. DOT Parts 192.227 and 192.229 specify under what conditions and how often a welder must be re-qualified.

Term	Definition
Qualified welding procedure	A tested and detailed method by which sound welds can be produced. Welding Engineers are typically consulted to determine the best method of welding two components to one another. Careful consideration as to types of electrodes, amperage settings, travel speed and direction, number of beads, and other critical variables are specified in the procedure. Before a welding procedure can be considered "qualified," a test weld must be made within strict adherence to the prescribed specifications. The test welds are then destructively tested to ensure proper fusing and penetration is achieved and complete fusion without any defects.
Rectifier	A device for converting alternating current to direct current, used in the pipeline industry for external corrosion control of underground pipe and other subsurface metal structures. The positive DC lead is connected to the ground bed anode system and the negative lead wire is attached to the protected pipe.
Regulator	A regulator is a device used to control the pressure, temperature, or pressure of the fluid or gas system it is connected to.
Regulator station	Equipment installed for the purpose of automatically reducing and regulating the pressure in the downstream pipeline or main to which it is connected. Included are piping and auxiliary devices such as valves, control instruments, control lines, the enclosure, and ventilation equipment.
Relief valve	An automatic valve designed to open and release excess pressure when a preset pressure setting is reached. The relieved pressure is dumped to a safe location that will not add to the upset pressure condition. These valves are sometimes referred to as a dump valve or pop-off valve. Relief valves are very important protective devices within the oil and gas industries and, as such, must be periodically inspected and calibrated to ensure they are working and adjusted properly.
Right-of-way	A strip of land, the use of which is acquired for the construction and operation of a pipeline or some other facility; may be owned outright or an easement taken for a specific purpose such as building and maintaining underground pipelines.
Riser	A general term for vertical runs of piping regardless of the size or application.
Rupture	A violent, rapid bursting open of a container: such as a segment of pipeline. Pipe ruptures usually occur due to defective material or due to corrosion or other impact related defects that weaken the walls of the pipe. The use of smart pigs for internal pipeline inspection can usually identify potentially problem areas before a failure occurs.
Sample piping	Pipe, valves and fittings used for the collection of samples of gas or other fluids. These sample areas are usually set up in easy access locations.
Scraper	Any device that is used to remove debris or deposits (such as scale, rust or paraffin) from tubing, casing, rods, flow lines, or pipelines.
Seamless pipe	A wrought tubular product made without a welded seam. It is manufactured by hot working steel or, if necessary, by subsequently cold finishing the hot-worked tubular product to produce the desired shape, dimensions and properties.

Term	Definition
Secondary stress	Stress created in the pipe wall by loads other than internal gas or fluid pressure. Examples are backfill loads, traffic loads, beam action in an unsupported span, loads at supports, and at connections of improperly supported pipe. Secondary stress can also be caused by thermal expansion and contraction forces.
Service line	In 49 CFR Part 192 this means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.
Service regulator	In 49 CFR Part 192 this 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.
Service tee	A service tee is a fitting attached to a customer's service piping with one leg capped off and used for maintenance access in case of plugging conditions. Also, a tee fitting is sometimes installed to hot tap on a main for the purpose of supplying gas to a new supply line or service line.
Shading	The placing of sand-like material free of any hard objects (rocks, etc.) below, around, and above the pipe during backfill in order to protect its surface from puncture or excessive abrasion.
Shut in pressure	The pressure at the casinghead or wellhead when all valves are closed and no oil or gas has been allowed to escape for a period of time, usually more than 24 hours and less than 72 hours.
Shut in test	After initial construction or assembly of smaller size gas distribution or service piping, it is customary to pressure test the joints to full system pressure and check for leaks. Since the gas cannot be readily seen, a solution of soap is applied to the joints to bubble in areas of leaking gas.
Smart pig	An instrumented inspection device used for internal pipe inspection. These specialized pigs travel along inside the pipe being pushed by the flow pressure in the line. These pigs can detect certain internal and external irregularities or anomalies in the pipe wall. An instrument on this type of pig records the existence, location, and relative severity of the anomalies, through use of recording equipment carried on board the pig. The recorded data is analyzed to determine the areas that need to be dug up and visually inspected to verify their existence and severity of recorded defects.
Solvent cement joint	A joint made in thermoplastic (usually polyvinylchloride or PVC) piping by the use of a solvent or solvent cement, which forms a continuous bond between the mating surfaces.
Specific language	A detailed and exact regulatory language prescribing materials, dimensions, and workmanship for something being built, installed, or manufactured. For example, thermoplastic pipe used for gas distribution systems must meet the ASTM D 2513 standard.

Term	Definition
Specific gravity	Specific gravity describes the physical characteristics of a substance in terms of whether the substance is lighter or heavier than a chosen standard. For a most liquids, its specific gravity will indicate whether it is lighter or heavier than water whereas natural gas is compared to air (water and gas have a specific gravity of 1.0).
Specified Minimum Yield Strength (SMYS)	In 49 CFR Part 192 this means specified minimum yield strength is: (a) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or (b) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b)
Squeeze off tool	A squeeze off tool is a maintenance tool used with plastic pipe that clamps down on the pipe to restrict or totally block flow and hold system pressures of gas and enable system repair. The tool consists of flat or curved surfaces with minimum radii that come together against the pipe wall. Stops, used to prevent the pipe being squeezed beyond a minimum allowable distance specified by the pipe manufacturer are normally an integral part of the tool.
Standard cubic foot per hour	Standard cubic feet per hour or SCFH is a volumetric flow rate measurement. It represents the amount of gas moved in one hour if it were at 60°F and under atmospheric pressure at sea level of 14.7 psi. Since gas moved within pipelines is rarely at these exact conditions, all raw flowrate data must be corrected to the standard so that variations in pressure and temperature can be accounted for.
Standard pressure test	A test to demonstrate that a pipe or piping system does not leak as evidenced by the lack of a drop in pressure over a specified period of time after the source of pressure has been isolated or removed.
Static electricity	Static electricity should always be a concern anytime flammable vapor could be present. Static build-up in plastic or even steel pipe can be significant and cause arcing and possible explosive conditions. This demonstration was conducted in a laboratory setting and clearly illustrates the power of static electricity. In this test setup, standard 2-inch plastic pipe was used to build a test loop. The loop was attached to a blower circulating vermiculite foam beads. A fluorescent light bulb is illuminated by the electrical charge given off by the generated static electricity even while being held by hand. Any time a pipe system is to be separated, always bond the two pieces to one another or install a path to ground to prevent arcing due to static.
Steel	An iron-base alloy, malleable in some temperature ranges as when initially cast, containing manganese, carbon and often other alloying elements. The strength of steel can be manipulated in its manufacturing process by varying the amounts of carbon and manganese and other alloys.
Stop cock	A valve located in the service line ahead of the service regulator, or ahead of the meter when there is no regulator. This valve can be used in emergencies to shutoff the supply of gas to residential or commercial users.
Stress	The resultant internal forces within a material that resists change in the size or shape of the material when acted on by external forces. Prolonged excessive stresses can

Term	Definition
	lead to cracking and general metal fatigue.
Stress level	The level of tangential or hoop stress, usually expressed as a percentage of "specified minimum yield strength," such as 20% SMYS.
Stringing	In pipeline construction, the process of delivering and distributing line pipe where and when it is needed on the right-of-way. Stringing also includes the delivery of special pre-bent joints or joints of special wall thickness and pipe grade to specific locations such as road crossings where heavy wall thickness may be specified by the contract or by regulations.
Structural attachments	Includes elements which are welded, bolted, or clamped to the pipe, such as clips, lugs, clamps, clevises, straps and skirts.
Supervisory Control and Data Acquisition (SCADA)	Supervisory control and data acquisition or SCADA systems are remote control systems used to monitor and control pipeline pump or compressor stations located along a pipeline system. Pressures, temperatures, flow rates, and other critical operational information is collected at the site and transmitted back to a centralized control room through a network of telephone, microwave, or satellite communication systems. Each site's data is then analyzed and displayed on a screen for the controllers to see. Any operating parameters out of pre-programmed ranges will normally generate an alarm. Controllers can also send out operational commands such as starting and stopping various types of station equipment, opening or closing valves, as well as increasing or decreasing flow rates or pressures.
Tapping tee	A tee fitting used to connect a service line to a main. The specialized tapping equipment includes a hole-cutter to tap into the main.
Temperature	Temperature is the amount of thermal energy a material possesses as measured on a definite scale. Within the pipeline industry, temperature is normally expressed in degrees Fahrenheit (°F) or degrees of Celsius (°C).
Tensile strength	Tensile strength is a unit of measure, usually expressed in psi, that describes the amount of stress a material can sustain before it fails or pulls apart. Tensile strength is greater than the initial yield strength of the material. In layman's terms, yielding refers to the stretching of the material and tensile refers to the actual separation or material failure.
Test point	A test point is an aboveground electrical test station where pipe-to-soil readings are taken to measure if the pipe is cathodically protected. As a minimum, a test point will have one terminal that has a wire electrically connected to the underground pipe or structure. Each pipeline under cathodic protection must have sufficient test points for electrical measurement to determine the adequacy of cathodic protection.
Therm	A therm is a unit of measurement describing the amount of heat a material can generate. In the gas industry, a therm represents 100,000 BTU’s, which is a common unit used in the sale of natural gas.
Thermoplastic pipe	A plastic pipe that is capable of being repeatedly softened by increase of temperature and hardened by decrease of temperature. These would include Polybutylene (PB), Polyethylene (PE), and Polyvinylchloride (PVC).

Term	Definition
Thermosetting plastic pipe	A plastic pipe which is capable of being changed into a substantially infusible or insoluble product when cured under application of heat or chemical means. Reinforced fiberglass is a good example.
Thickness	Thickness normally describes the measurement from one surface through the material to the opposite side. When dealing with pressure holding vessels such as pipe, thickness is a major factor in determining its design pressure holding capability.
Tracer wire	Tracer wire is metallic wire that is buried along with plastic pipe. The typical size of wire used should be at least 12 gauge. A pipe locator can then detect the metal in the wire and indicate the location of the adjacent buried plastic pipe.
Transmission line	In 49 CFR Part 192 this means a pipeline, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) 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.
Transportation of gas	In 49 CFR Part 192 this means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.
Trench	A trench is a long ditch cut into the ground, which is dug by a backhoe or by a specialized digging machine such as a trencher. Underground installation of transmission, mains, or service pipelines, regardless of the kind of pipe are usually installed in a trench and then backfilled to cover it up.
Trunk line	A long distance transmission interstate mainline piping system used to transport natural gas or liquids from the producing areas of the country to the refineries or distribution facilities. Trunk lines are usually large diameter pipe - typically above 20 inches.
Tubing	A string of pipe set into a well through which oil or gas is produced. Tubing also refers to smaller diameter pipe (usually stainless steel or copper) with diameter usually less than 1/2 inch and is generally used as instrumentation or control piping, to sense mainline conditions for instrumentation monitoring and control.
Ultrasonic testing	Ultrasonic testing is a non-destructive inspection method frequently used in the pipeline industry. It consists of an instrument with a probe that generates high-frequency sound waves and measures their reflection off the pipe inner wall. The reflected signals can be used to determine and locate defects such as laminations in the wall of pipe, as well as measure the remaining wall thickness. This device is particularly useful in locating internal corrosion in steel pipe where some of the inner wall surface may be corroded away.
Unaccounted for gas	The difference between the total gas purchased from all sources and the total gas accounted for as sales, net interchange, and internal company use. This difference

Term	Definition
	includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly billing lag.
Underground storage	The utilization of subsurface facilities for storing gas which has been treated and transferred from its original location to temporary storage. The stored gas can later be withdrawn to augment high demand flow rates. These underground storage areas are usually natural geological reservoirs such as depleted oil or gas fields, salt domes, or water-bearing sands sealed on the top by an impermeable cap rock. The facilities may be manmade or natural caverns.
Uniform corrosion	Uniform corrosion is metal deterioration occurring relatively evenly over the entire metal surface. Rather than a few localized pits, uniform corrosion is seen as a textured surface similar to that of an orange peel where the surface area is deteriorating at an equal rate.
Union	A specialized threaded fitting used to couple two joints of threaded pipe together, without having to turn or dismantle either run of pipe.
Upper explosive level (UEL)	Read from the CGI, the upper explosive limit is the maximum amount of airborne chemical that can be present in an air-chemical mixture and still have it be explosive. A fuel and air mixture above the UEL is considered too rich to ignite.
Vacuum truck	A vacuum truck is a specially equipped vehicle used to suck up and transport various liquids. Vacuum trucks are used extensively in the petroleum and gas industries in many aspects of pipeline maintenance. Negative pressure is created in the truck's cargo vessel by an on-board vacuum pump. Heavy flexible hoses are used to collect the liquids and direct them into the tank.
Valve	A valve is a mechanical device installed on a pipe or pipeline used to control the flow of gas or liquid. A valve can be used solely for fully open or closed applications, to control the direction of flow, or used to throttle flow or regulate pressure.
Valve box	A valve box is a protective container usually installed partially below the ground surface to allow operation or maintenance access to underground pipeline valves. The valve box also prevents unauthorized tampering.
Vault	A vault is normally an underground concrete structure that houses valves and/or pressure regulation equipment. Depending on the size or volume of the vault, it must be ventilated or sealed per 49 CFR Part 192.187.
Welding process	A grouping of methods by which metals are fused together. Examples of processes are: submerged metal arc welding, oxyacetylene welding, and resistance welding.
Wet gas	Natural gas containing liquefiable hydrocarbons such as natural gasoline, butane, pentane and other light hydrocarbons that can be removed by chilling, pressurization, or other extraction methods. It also refers to gas that contains water vapor in excess of 7 pounds per million cubic feet (mmcf).
Wick-type odorizer	A wick-type odorizer is a piece of equipment that odorizes the natural gas by having the natural gas flow across a wick in a pipe bottle saturated with odorant. Wick-type odorizers are generally used for odorizing individual lines such as farm taps.

Term	Definition
X-Ray	X-ray is a non-destructive radiographic procedure used to analyze the quality of welded joints in metallic pipe. The electromagnetic waves are projected onto the inspection area by a radioactive source. These waves penetrate through the metal and cast an image onto a special strip of film. The film is then developed and interpreted by a trained technician to determine if there are any metallurgical defects in the base metal or the weld area.
Yield strength	The yield strength is the stress level at which a material exceeds its elastic limits and the material begins to deform permanently. For metal pipes used in the petroleum industry, the yield strength can be manipulated depending on the proportions of steel, carbon, and manganese in its production.

Existing Code Language:	(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart. (b) Each operator shall keep records necessary to administer the procedures established under §192.605. (c) The Administrator or the State Agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.237 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-75, 04-26-96
Interpretation Summary	Date: 07-17-72 Maintaining maps as a part of pipeline records, if these maps are used in support of record keeping requirements.
Interpretation Summary	Date: 05-09-91 Computerized records are adequate to replace paper records.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted
New Guidance Material	- Paragraph §192.603(a) is a general compliance requirement that is used in conjunction with another specific violation within this subpart. - When a regulation does not specifically require records, then paragraph §192.603(b) can be used when appropriate records have not been kept.
Examples of a Violation	- Operating a segment of the pipeline system that is not in accordance with this subpart. - Records necessary to administer the plan are not maintained. - Computerized records were not managed properly, lost, deleted or otherwise destroyed. - Records lack sufficient details to document the actual work performed.
Evidence Guidance	- Records associated with the missing record that surround the time period of the missing record. - Statement from operator=s designated representative. - Documentation to demonstrate who, when and where records were requested.

Other Special Notations	None noted

Existing Code Language:	(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.
Origin of Code	192-71, 02-11-94
Last FR Amendment	192-71A, 03-17-95
Interpretation Summary	Date: 10-24-94 Operators must include in their manuals as much design and construction information, such as welding or other joining procedures, as is necessary to carry out operation, maintenance, and emergency response activities. For example, if a pipeline is to be repaired by replacing a segment of pipe, the operator's O&M manual would have to have design and construction information appropriate for that type of repair. Also, the O&M manual must contain procedures that enable operating and maintenance personnel to obtain as much original design and construction information as they need to carry out their assignments. However, such original information may be maintained apart from the manual.
GPTC	Industry guidance available
Other Ref. Material & Source	Date: 03-09-01 Advisory Bulletin ADB-01-01, Closure of Gas Shut-off Valves Serving Permanently Moored Vessels (PMV) During High Water Conditions.
Other Ref. Material & Source	Date: 05-16-01 Advisory Bulletin ADB-01-02, Emergency Plans and Procedures for Responding to Multiple Gas Leaks and Migration of Gas into Buildings.

New Guidance Material	- The operator=s O&M procedures may be a comprehensive set of cross-referenced volumes set up according to functional subjects or a single manual. - Procedures are required for functions and facilities in a system. -The procedures are not just for the field personnel. - Procedures are required for tasks normally performed at the engineering, gas control, and other headquarters type functions as applicable to O&M tasks. - The procedures should be clear, straight forward, and applicable to the company=s system. - Abnormal operations procedures must be included for transmission line operators. - All these procedures must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. - An operator must follow its written procedures, even if the procedures exceed specific code requirements.
Examples of a Violation	- The procedure is of a general nature and would provide little guidance when needed. - The procedure parrots the regulation. - There is no procedure. - Written procedures that have not been followed. - Written procedures not reviewed and updated at required intervals.
Evidence Guidance	- Observation and/or photographs that indicate written procedures are not being followed. - Operator=s records and statements. - Copy of O&M plan or applicable portion that shows omission or deficiency in the plan. - Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	- If a Joint Team O&M Inspection has been completed, procedures do not have to be evaluated for content for five years from the inspection date. However, if inadequate procedures are discovered, appropriate amendments shall be required and findings discussed with O&M Team Leader. - Procedures concerning new regulations that were placed in force after the Joint Team O&M Inspection, and those known to have changed since the Joint Team Inspection, should be reviewed.

Existing Code Language:	(b) Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations. (1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part. (2) Controlling corrosion in accordance with the operations and maintenance requirements of Subpart I of this part. (3) Making construction records, maps, and operating history available to appropriate operating personnel. (4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner. (5) Starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices. (6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service. (7) Starting, operating and shutting down gas compressor units. (8) Periodically reviewing 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. (9) Taking 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. (10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including: (i) Provision for detecting external corrosion before the strength of the container has been impaired; (ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and, (iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity. (11) Responding promptly to a report of a gas odor inside or near a building, unless the operator=s emergency procedures under §192.615(a)(3) specifically apply to these reports.
Origin of Code	192-71, 02-11-94
Last FR Amendment	192-93, Published 09-15-03, Effective 10-15-03

Interpretation Summary	Date: 10-22-92 Regulator stations must be inspected and tested to comply with §192.739 using any practicable method that will demonstrate the presence or absence of the listed qualities. Set-point, lock-up, and full-stroke-operation would be part of the inspection and testing if such tests are practicable at the station concerned. If not, whatever other tests are practicable in meeting the requirements of §192.739 must be used. Specific procedures should be documented in the utility's operating and maintenance plan prescribed by §192.605 (a).
Interpretation Summary	Date: 07-23-92 The 1968 edition of ASME B31.8 Code contains the following definitions: Bottle-type holder is any bottle or group of interconnected bottles installed in one location, and used for the sole purpose of storing gas. They are gas-tight structures completely fabricated from pipe with integral drawn, forged, or spun end closures and tested in the manufacturer's plant. Based on these definitions, we believe that valve actuator bottles are not bottle-type holders. Although they may be bottles that store gas, gas storage is not their sole purpose. In fact, their primary purpose is to provide power to actuate the valve when necessary. Thus, they are not subject to §§192.175 and 192.177.
GPTC	Industry guidance available.
Other Ref. Material & Source	Date: 01-19-94 Advisory Bulletin ADB-94-01, Supplemental Incident/Accident Reports.
Other Ref. Material & Source	Date: 03-11-99 Advisory Bulletin ADB-99-01, Potential Failure Due to Brittle-Like Cracking Certain Polyethylene Plastic Pipe Manufacturing by Century Utility Products Inc.
Other Ref. Material & Source	Date: 08-29-00 Advisory Bulletin ADB-00-02, Internal Corrosion in Gas Transmission Pipelines.

New Guidance Material	- Operator=s O&M procedures may be a comprehensive set of cross-referenced volumes set up according to functional subjects or a single manual. - Procedures are required for functions or facilities in a system. The procedures are not just for the field personnel. - Procedures are required for tasks normally performed at the engineering, gas control, and other headquarters type functions as applicable to O&M tasks. - The procedures should be clear, straight forward and applicable to the company=s system. - Abnormal operations procedures must be included for transmission line operators. - All these procedures must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. -More specific than the requirements addressed in §192.605(a), as noted above. Personnel conducting pipeline operations need direct access (either on paper or electronically) to procedures, without delay when emergencies arise. - §192.605(b) (8) is directed to procedures refinement, not employee evaluation. - Operators may apply various techniques to determine the adequacy of its normal O&M procedures, some examples are: . Incentive programs to identify procedural improvement . Procedure suggestion block on maintenance forms . Tailgate meeting agenda item . Discussions during employee performance review . Ongoing management of change process . Near miss and accident investigation analysis. - Refinement and efficiency of procedures must not compromise safety. - It is acceptable for operators to use the manufacturer=s recommended maintenance practices for compressor station maintenance (engine books, maintenance bulletins, etc.) regarding the applicable equipment at each location. If used, documents must be available at the work location (manuals at the office responsible for the work is acceptable). - It is acceptable to post the specific start-up and shut-down instructions for each compressor unit at or near the local control panel used for operating the equipment; and have generic guidance procedures in its O&M Plan. - Isolation and ESD procedures must be specific for each location. - Adequately structured procedure manuals will allow personnel to easily find specific O&M procedures. - Operators must be able to provide a list of manuals that represent the entire set of required procedures. - With regard to the potential overlap with OSHA rules. Section 4(b) (1) of the OSHA Act prohibits OSHA from exercising authority over working conditions when another agency exercises authority through regulation. - The OPS procedures required to protect employees from vapors in excavations is different than OSHA confined space procedures.

Examples of a Violation	-The procedure is of a general nature and would provide little guidance when needed. -The procedure parrots the regulation. -There is no procedure. - The operator=s procedures for taking adequate precautions in excavated trenches do not include the use of appropriate instruments to test the atmosphere in the trench. -The only procedure for addressing vapors in excavated trenches is OSHA=s confined space procedures.
Evidence Guidance	- Copy of O&M plan or applicable portion that shows omission or deficiency in the plan. - Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	- If a Joint Team O&M Inspection has been completed, procedures do not have to be evaluated for content for five years from the inspection date. However, if inadequate procedures are discovered, appropriate amendments shall be required and findings discussed with O&M Team Leader. - Procedures concerning new regulations that were placed in force after the Joint Team O&M Inspection, and those known to have changed since the Joint Team Inspection, should be reviewed.

Existing Code Language:	(c) Abnormal operation. For transmission lines, the manual required by paragraph (a) of this section must include 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 a 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. (5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connections with their distribution system.
Origin of Code	192-71, 02-11-94
Last FR Amendment	192-71A, 03-17-95
Interpretation Summary	None
GPTC	Industry guidance available
Other Ref. Material & Source	None noted

§192.605(c)	Procedural Manual - Abnormal Operations

New Guidance Material	- Abnormal conditions and emergency conditions are not equivalent. - Abnormal conditions do not pose an immediate threat to life or property as do emergency conditions. Abnormal conditions are generally less severe, but could escalate to emergency conditions if not promptly corrected. - Any transmission line operator that chooses to treat abnormal conditions as emergency conditions still must comply with §192.605(c) and have separate procedures for abnormal conditions. - The operator=s O&M procedures may be a comprehensive set of cross-referenced volumes set up according to functional subjects or a single manual. - Procedures are required for all facilities in the system. - The procedures are not just for the field personnel. - Procedures are also required for tasks normally performed at gas control, engineering and other headquarters type functions as applicable to O&M tasks. - The procedures should be clear, straight forward, and applicable to the company=s system. - Abnormal operations procedures must be included for transmission line operators. - All these procedures must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. - §192.605(c)(4) is directed to procedures refinement, not employee evaluation. - Operators may apply various techniques to determine the adequacy of its abnormal O&M procedures, some examples are: . Root cause analysis . Post event reports . Tailgate meeting agenda item . Near-miss analysis and reports . Simulation or event re-construction reviews . Abnormal operations drills and mock exercises. - Refinement and efficiency of procedures must not compromise safety.
Examples of a Violation	- The procedure is of a general nature and would provide little guidance when needed. - The procedure parrots the regulation. - There is no procedure.
Evidence Guidance	- Copy of O&M plan or applicable procedure that shows omission or deficiency in the plan. -The only procedure for addressing vapors in excavated trenches is OSHA=s confined space procedures. - Copy of O&M plan or applicable portion that shows omission or deficiency in the plan. - Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	None noted

Existing Code Language:	(d) Safety-related condition reports. The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of ' 191.23 of this sub-chapter.
Origin of Code	192-71, 02-11-94
Last FR Amendment	192-71A, 03-17-95
Interpretation Summary	None
GPTC	Industry guidance available.
Other Ref. Material & Source	Amendment 191-6 Date: 09/20/88 Operators of gas pipelines associated liquefied natural gas (LNG) facilities, and hazardous liquid pipelines are required to begin reporting certain safety-related conditions in addition to the incidents and accidents they currently are required to report. They also must revise their operating and maintenance (O&M) plans to enhance discovery of the conditions. These new requirements were mandated by the 99th Congress in the pipeline safety authorization act for fiscal year 1987, Pub. L. 99-516 (October 22, 1986). The reports are intended to prevent known hazardous conditions from going uncorrected by prompting government intervention, if needed, to avoid the occurrence of an incident or accident. Section 3 of Pub. L. 99-516 directs the Secretary of Transportation to issue regulations requiring operators of gas and hazardous liquid pipeline facilities (other than operators of master meter systems) to report certain safety-related conditions, and to provide for discovery of such conditions in their inspection and maintenance plans. More specifically, the following new reporting requirements were added to section 3(a) of the Natural Gas Pipeline Safety Act of 1968 (NGPSA) (49 App. U.S.C. 1672(a)): (3) Not later than 12 months after the date of the enactment of this paragraph, the Secretary shall issue regulations requiring each person who operates pipeline facilities, not including master meters, to report to the Secretary— (A) any condition that constitutes a hazard to life or property, and (B) any safety-related condition that causes or has caused a significant change or restriction in the operation of pipeline facilities. Reports submitted under this paragraph shall be in writing and shall be received by

	the Secretary within 5 working days after any representative of a person subject to the reporting requirements of this paragraph first determines that such condition exists. Notice of any such condition shall concurrently be supplied to appropriate State authorities.
Other Ref. Material & Source	Amendment 191-7 Date: 08/07/89 This final rule document makes clarifying changes to recently established reporting requirements regarding safety-related conditions, and states agency policy regarding discovery of those conditions by smart pigs. In addition, the pipeline safety enforcement procedures are modified to reflect statutory changes authorizing increased civil penalties for violations and specific criminal penalties for destruction of signs or markers. In accordance with section 3 of Pub. L. 99-516, RSPA issued regulations requiring operators of gas and hazardous liquid pipeline facilities subject to 49 CFR Parts 192, 193, and 195 to (1) report to RSPA and State agencies the existence of certain safety-related conditions on pipelines in service, and (2) add to their operating and maintenance procedures instructions that enable personnel to recognize potentially reportable conditions (53 FR 24942, July 1, 1988). The regulations require operators to file written reports of the conditions "within 5 working days * * * after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition." (§§191.25(a) and 195.56 (a)) The regulations require operators to describe the precise location of the condition being reported. Of the reports received thus far, some have provided such detail as the milepost, but have not indicated in which State and city, town or county, the condition exists. Therefore, §§191.25 (b)(6) and 195.58(b)(6) are revised to assure that these critical factors in describing location are provided. The regulations also require operators to provide a general description of the safety-related condition being reported. This description should include the name of the commodity transported or stored to indicate the nature of the hazard involved. However, many operators have not included this information in their reports. Therefore, the name of the commodity has been specifically included in the description required by §§191.25(b)(7) and 195.56(b)(7). In the case of a hazardous liquid pipeline that currently carries more than one commodity, the name of each commodity is required.

New Guidance Material	- The operator=s O&M procedures may be a comprehensive set of cross-referenced volumes set up according to functional subjects or a single manual. - Field operations and maintenance personnel, gas controllers or corrosion personnel are expected to recognize potential safety-related conditions. - Operators should designate what personnel are ultimately responsible to assess and determine the existence of safety-related conditions. - Inspectors should ask if any of the reported safety related conditions were in or affected a HCA. Safety related conditions that are in a HCA must meet the timing requirements of the Integrity Management Rules (both discovery and remediation).
Examples of a Violation	- The procedure is of a general nature and would provide little guidance when needed. - The procedure parrots the regulation. - There is no procedure.
Evidence Guidance	- Copy of O&M plan or applicable procedure that shows omission or deficiency in the plan. - Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	None noted

Existing Code Language:	(e) Surveillance, emergency response, and accident investigation. The procedures required by ''192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section
Origin of Code	192-71, 02-11-94
Last FR Amendment	192-71A, 03-17-95
Interpretation Summary	None
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted
New Guidance Material	- It is acceptable to combine the OPA Plan and the Emergency Plan separate from the O&M; however, the O&M Plan must cross reference these plans and they must be available for an OPS Inspection of their facility. - The operator=s O&M procedures may be a comprehensive set of cross-referenced volumes set up according to functional subjects or a single manual. - The procedures are not just for the field personnel. Procedures are also required for tasks normally performed in gas control, engineering and other headquarters type functions as applicable to O&M tasks. - The procedures should be clear, straight forward and applicable to its system.
Examples of a Violation	-The procedure is of a general nature and would provide little guidance when needed. -The procedure parrots the regulation. -There is no procedure.
Evidence Guidance	- Copy of O&M plan or applicable procedure that shows omission or deficiency in the plan. - Documented conversations with operator personnel who are charged with establishing the plan.
Other Special Notations	None noted

§192.609	Change in Class Location: Required Study

Existing Code Language:	Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates 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.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	None
Interpretation Summary	Date: 10-12-79 "Hoop Stress" is the actual stress produced by a given internal fluid pressure in a pipeline and is calculated using "Barlows" formula. This calculation does not involve the use of the de-rating factors specified in §192.105, Design formula for steel pipe.
Interpretation Summary	Date: 08-04-86 Grand-fathered segments that operate at pressures allowed under §192 .619(c) and take pressure gradient into account, can continue to operate at these pressures, as long as the MP5 Apressure gradient@ pressures within the pipeline segment are not exceeded. The MAOP of an element inside the segment cannot exceed it=s old (MP5) operating level. The intent of §192 .619(c) is to allow old safe operations to continue, but not be exceeded.
GPTC	None provided.
Other Ref. Material & Source	None noted

§192.609	**Change in Class Location: Required Study**

New Guidance Material	- Refer to §192.5 and the operator=s procedures for class location determination (§192.609(a)). - The comparison that is required of §192.609(b) must address the applicable Part 192 requirements for the present class location. For example, if a pipeline segment is to be replaced as a result of a class change, then the replacement pipe segment must comply with all of the applicable Part 192 regulations for new pipe in the present class location, §192.13(b). - Transmission line valve spacing requirements of §192.179 have to be reviewed if replacement pipe is a part of a class change project. As an example, if a transmission pipeline segment is replaced within a current class 3 location, a sectionalizing block valve must be within 4 miles of each end of the replacement pipe prior to placing the segment in operation. This may require the installation of a new block valve, either in the existing or replacement pipe. The enforcement of this requirement will only be applied to pipeline segment replacement projects initiated after 05-01-98 (i.e. the Viking Case). - Pressure gradient, if applicable, must be considered in the study, §192.609(e). - MAOPs based on MP5 pressure gradients may still apply. As an example, the MP5 pressure at the discharge side of compressor station A may be greater than the MP5 pressure at the suction side of compressor station B. In this case, established MAOP=s along a segment or section may differ. The guiding principal is that the MAOP of an element inside the segment cannot exceed it=s old (MP5) operating level. - Pressure gradient may apply to operating pressure. Gradients may be used by operators to demonstrate that a downstream segment (near the suction side of a compressor station, for example) operates at a hoop stress commensurate with the present class location. Operator should be able to provide documentation and records that verify that the pressure gradient is valid for the established MAOP, such as historical nearby pressure data, foreseeable operating scenarios, operational engineering study, etc. Also, the operator would be expected to have pressure control or nearby operating pressures continually monitored and, if necessary, recorded.
Examples of a Violation	- The operator cannot demonstrate that the required study included, or adequately addressed, the requirements of this paragraph.

Evidence Guidance	- Operator=s documented study. - Engineering drawings (as-built, approved for construction, plans, etc.). - Class location/change procedures. - Class location/change records. - Patrol records. - MAOP verification records (pressure tests, MP5 records, pipe specs, design, installation, etc.). - Operating records (pressure charts/data, operating scenarios, etc.). - Maintenance records (leak history, inspection reports, tests, smart pig data, cathodic protection, etc.). - Observations, documentation (including photos). - Operator statements.
Other Special Notations	None noted

§192.611	Change in Class Location: Confirmation or Revision of MAOP

Existing Code Language:	(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements: (1) If the segment involved has been previously tested in place for a period of not less than 8 hours, the maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations. (2) The maximum allowable operating pressure of the segment involved 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) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria: (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 corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations. (b) The maximum allowable operating pressure confirmed or revised in accordance with this section, may not exceed the maximum allowable operating pressure established before the confirmation or revision. (c) Confirmation or revision of the maximum allowable operating pressure of a segment of pipeline in accordance with this section does not preclude the application of §§192.553 and 192.555. (d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24 month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-94, Published 06-14-04, Effective 07-14-04

Interpretation Summary	Date: 06-04-71 Pipelines that are located in Class 2, 3 and 4 locations, regardless of when the segment was placed in service, cannot operate above the hoop stress that is commensurate with the present class location (ref. §192.619(a)(1)), unless the MAOP has been confirmed or revised in accordance with §192.611. §192.611 does not apply to pipelines located in Class 1 locations that operate above 72% SMYS in accordance with §192.619(c). See below for additional information. Pipelines in Class 2, 3 and 4 locations must have their operating pressures confirmed or revised in accordance with section §192.611. However, pipelines in Class 1 locations operated at pressures which are not commensurate with that class location, based on the design stress levels of section §192.619(a)(1), may continue to operate at their previous MAOP under the "grandfather" clause of section §192.619(c).
Interpretation Summary	Date:10-12-79 "Hoop Stress" is the actual stress produced by a given pressure in a pipeline and is calculated using "Barlows" formula. This calculation does not involve the use of the de-rating factors specified in §192.105 Design formula for steel pipe.
Interpretation Summary	Date: 11-11-71 (The 18 month requirement has been changed to 24 months by the latest code section revision). (This interpretation was for §192.611(e)(2) which has been superseded by the latest revisions to this section). There is no requirement for an annual updating for the class location. For operators having lines operating at or above 40% SMYS the operator must be constantly on the alert for changes in class location, and if necessary take action within 18 months of the change in class location. It does not mean that they may take action 18 months after discovering such a change.
Interpretation Summary	Date: 05-12-78 An operator has 18 months from the time a change in class location occurs to complete the confirmation or revision. The 18-month period begins upon completion of a structure which results in a new class location. The regulations do not support the theory that the 18-month period begins when a §192.609 study is completed. Under §192.609, an operator must make the study "whenever an increase in population density indicates a change in class location." Thus, the 18-month period begins at essentially the same time as the study, not when it is completed.

Interpretation Summary	Date: 09-15-89 Selection and implementation of one option, e.g., lowering pressure, does not preclude later implementation of another option, e.g., retesting. OPS believes it reasonable to interpret §192.611 to permit an operator who has previously reduced the pressure on a pipeline in response to a class location change to revisit that pipeline and raise the operating pressure within the limits specified in §192.611(a)(1).
Interpretation Summary	Date: 12-17-96 Both the "arc method" and the "perpendicular/parallel method" are acceptable for determining the 220 yard boundary for the Acluster of buildings@ referenced in §192.5(c)(2).
Other Ref. Material & Source	Date: 08-19-70 (from preamble in Original Code Document) §192.5. A number of comments pointed out that the proposed class location definitions could create a 2-mile stretch of high class location solely to protect a small cluster of buildings at a crossroads or road crossing. To avoid this situation, a new paragraph (f) has been added to allow adjustment of class location boundaries. A Class 4 location boundary may be moved to within 220 yards of the nearest four-story building. Whenever a Class 2 or 3 location is required by a cluster of buildings in otherwise open country the boundary may be moved to within 220 yards of the nearest building in the cluster.
GPTC	None provided.

Other Ref. Material & Source	Amendment 192- 94 06-14-04 (Preamble) Change in Class Location: Confirmation or Revision of Maximum Allowable Pressure. Section 192.611 Section 192.611(d) allows 18 months for a gas pipeline operator to confirm or revise the maximum allowable operating pressure (MAOP) of a pipeline after a change in class location. The proposed amendment would increase the time period from 18 months to 24 months, and clarify that the 24-month time period begins when a building or buildings are ready for occupancy and not when the operator discovers that there are new buildings or completes a class location review. Although the proposed change was unopposed by most commenters, some SIRRC members and one other commenter objected to the adoption of a 24-month time period because it would have an adverse impact on operators without any corresponding benefit. Upon further consideration, we adopt the increase in the time period from 18 months to 24 months as proposed, but modify the proposed language to clarify that the time period begins when the results of a study conducted under § 192.609 indicate a change in class location. Moreover, this result is also consistent with the intent of Section 854.2 of standard ASME B31.8. Therefore, we adopt the proposed language.
Other Ref. Material & Source	Date unknown OPS Notice 70-4, 35 F.R. 5012. (One of the Notices prior to Original document). AThe number of buildings within this sliding mile at any point during the movement determines the class location for the entire mile within the sliding mile. Whenever there is a change in class location which will cause an apparent overlapping of class locations, the higher numbered class location would be applicable.@
Other Ref. Material & Source	Amdt. 192-78B dated 7/3/96 Class Locations Section 192.5 RSPA revised the class location definitions (Sec. 192.5) to provide clarity and minimize the possibility of needless design and construction expenditures (61 FR 28783; June 6, 1996). One revision concerned the boundary adjustment of Class 2 and 3 locations that involve a cluster of buildings intended for human occupancy (old Secs. 192.5(f)(2) and (f)(3). With this adjustment, a Class 2 or 3 location on a pipeline ends 220 yards from the nearest building in the cluster. As revised, the adjustment applies only when all buildings in a 1-mile class location unit (the basis for classification under Sec. 192.5) are in a single cluster (new Sec. 192.5(c)(2)). Since the revision was published, RSPA has learned that many operators customarily apply the cluster adjustment irrespective of buildings outside the cluster. We also learned this practice has been tacitly accepted by RSPA enforcement

	personnel and may be consistent with instruction at RSPA's Transportation Safety Institute. Under these circumstances, the revised regulation could have a significant, unintended economic impact on the pipeline industry. Also, because this pipeline classification practice reflects the adjoining population density, the practice is consistent with pipeline safety. Therefore, we are correcting new Section 192.5(c)(2) so there is no substantive change from old Sections 192.5(f)(2) and (f)(3).
New Guidance Material	One of the following three action items has to occur for a pipeline that operates at more than 40% of SMYS and is in satisfactory condition, if the class location changes and the hoop stress (at MAOP) is not commensurate with the present class location. (§192.611(a)) (1) Confirm or revise (reduce) the segment MAOP based on a previous 8 hour test. The revised/confirmed MAOP cannot exceed any of the following: - 0.8 x previous test pressure in class 2 location - 0.667 x previous test pressure in class 3 location - 0.555 x previous test pressure in class 4 location - 72% of pipe SMYS in class 2 location - 60% of pipe SMYS in class 3 location - 50% of pipe SMYS in class 4 location (2) Reduce segment MAOP so that the pipe stress level is commensurate with the present class location (3) ARe-qualify@ the segment by testing it in accordance with subpart J. The revised/confirmed MAOP cannot exceed any of the following: - 0.8 x the test pressure in class 2 location - 0.667 x the test pressure in class 3 location - 0.555 x the test pressure in class 4 location - 72% of pipe SMYS in class 2 location - 60% of pipe SMYS in class 3 location - 50% of pipe SMYS in class 4 location - For any existing pipeline segment where a confirmation or revision of the MAOP is necessary because of the class location change study required of §192.609, the operator has 24 months from the time of the class location change to either revise or confirm the segment MAOP (the 24 month period begins upon completion of a structure or other changes which result in a new class location). (§192.611(d)) - There is no specified time interval for the operator to detect an actual class change; however, the operator must complete the study, confirmation and revision within 24 months of the time the structure was completed. - If the operator chooses to reduce the segment MAOP (§192.611(d)) within the 24 month period in order to comply with either: §192.611(a)(1) (reduction based on a previous test pressure); or §192.611(a)(2) (reduction based on allowable hoop stress), the operator has the option of establishing the segment MAOP after the 24 month period by testing the segment per §192.611(a)(3). - Both the "arc method" and the "perpendicular/parallel method" are acceptable for

	determining the 220 yard boundary for the Acluster of buildings@ referenced in §192.5(c)(2). - A grandfathered (§192.619(c)) MAOP in a class 1 area is voided when the pipeline segment class change occurs, unless the segment hoop stress is commensurate with the new class location. - Special Note....Pipelines that are located in Class 2, 3 and 4 locations, regardless of when placed in service, cannot operate above the hoop stress that is commensurate with the present class location, unless the MAOP has been confirmed or revised (or is being confirmed or revised due to a recent class location change) in accordance with §192.611. In other words, these segments were not Agrandfathered@ from the requirements of §192.611, and may require over-pressure protection equipment.
Examples of a Violation	- Any MAOP confirmation or revision that is required of §192.611 has not been completed within 24 months of an actual class location change. - An operator has performed one of the above-listed three action items in order to confirm or revise the MAOP of a pipeline segment that is in unsatisfactory condition under §192.611. - The confirmed or revised MAOP established under §192.611 exceeds the MAOP that existed before the confirmation or revision.
Evidence Guidance	- Operator class location maps, data indicating building construction completion. - Statements from contractors or inhabitants indicating building construction completion. - Copies of building permits, city or county records, date of utility connections, etc., that may indicate construction completion date. - Operator class location change records, patrol reports, class change studies, etc. - Pipeline segment MAOP records, segment hoop stress, test history, actual operating pressure, etc. - Operator class change procedures. - Operator statements. - Field observations (photos, for example).
Other Special Notations	None noted

Existing Code Language:	(a) Each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in water less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005. (b) Each operator shall conduct appropriate underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from low mean water based on the identified risk. (c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall- (1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802 of the location, and, if available, the geographic coordinates of that pipeline; (2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and, (3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year the discovery is made, place the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation. (i) An operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial. (ii) If an operator cannot obtain required state or Federal permits in time to comply with this section, it must notify OPS; specify whether the required permit is State or Federal; and justify the delay.
Origin of Code	192-67, 12-05-91
Last FR Amendment	192-98, Published 08-10-04, Effective 09-09-04
Interpretation Summary	None provided
GPTC	None provided.

Other Ref. Material & Source	Final Rule Preamble: Fisheries Institute suggested the following inlet waters list based on known fishing areas (not an exhaustive listing): 1. Fresh Water Bayou/Inter- coastal Waterway to Calcasieu River, Cameron, La. 2. Calcasieu Pass, Cameron, Louisiana. 3. Intercoastal Waterway to Morgan City, Louisiana. 4. South West Pass across Vermillion Bay, Intercoastal City, Louisiana. 5. Fresh Water Bayou, Intercoastal City, Louisiana. 6. Houma Navigation Channel/Intercoastal Waterway to Bayou Chene, Morgan City, La. 7. Houma Navigation Channel through Grand Calliou Bayou/Calliou Lake, DuLac, La. 8. Houma Navigation Canal through Cat Island Pass, DuLac, Louisiana. 9. East Pascagoula River, Moss Point, Mississippi.
Other Ref. Material & Source	33 CFR Part 64 Title 33--Navigation and Navigable Waters, Chapter 1 B Coast Guard, Department of Transportation Part 64 B Marking of structures, sunken vessels and other obstructions
New Guidance Material	- The required procedure (§192.612(a)) to identify pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep mean low water is an on going periodic requirement to review and update. - The NRC reporting requirements and subsequent remediation for the discovery of a GOM/inlet offshore pipeline condition at any time after the required survey in waters less than 15 feet (4.6 meters) deep that poses a hazard to navigation is a continuing requirement. - Notification to the NRC is required, even though the condition does not meet the NRC leak reporting criteria. - Periodic inspection of underwater pipelines should be based upon the operator's procedures. Underwater pipelines should be inspected based upon operator procedures unless the operator can show compelling evidence of why an inspection of the pipeline is not required. An example would be a horizontal drilled river/bay crossing that has the pipe with an original cover of 20 feet in a water crossing area that has low water flow velocities and minimum bank and bottom scouring.

Examples of a Violation	- The operator has not prepared a listing of all pipelines requiring underwater inspection and a procedure for determining when these inspections shall be conducted. The procedures must be in effect August 10, 2005. - The operator does not perform its operational/engineering review of pipelines requiring underwater inspection based upon the operator's procedures. Underwater pipelines shall be periodically inspected based upon the operator's procedure measures. - An operator after discovering that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, as result of an inspection under paragraph (a and b) of this section, or upon notification by any person, the operator has not complied with any of the following - (1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802 of the location, and, if available, the geographic coordinates of that pipeline; (2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and, (3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year the discovery is made, place the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation. An operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial.
Evidence Guidance	- No operator procedures for performing operational/engineering analysis of the appropriate underwater pipelines. - No initial identification or ongoing updates of underwater pipelines that should be evaluated and inspected based upon this code requirement. - No documentation or records available to support that the initial underwater survey was required (all offshore pipelines in water exceeding 15 feet (4.6 meters) in depth), or that the required survey was conducted. - No NRC report on file or a NRC report indicating that they were *not promptly* notified within 24 hours of a hazard to navigation pipeline condition (the top of the pipe is less than 12 inches (305 millimeters) below the seabed in waters less than 15 feet (4.6 meters) deep). - The OPS 2 hour minimum guideline for *promptly* reporting a reportable leak to the NRC cannot be cited; the rule specifically defines prompt notification to be any time less than 24 hours. - The discovered offshore pipeline not meeting the minimum 12 inches (305 millimeters) of cover requirement (§192.612(c)(3), was not marked (buoys) in accordance with §192.612(c)(2) requirements, and/or at the ends and within the required minimum distance intervals.

	- No documentation or records available to support that reburial of the pipeline was performed as required §192.612(c)(3) or that the operator has not obtained a waiver.
Other Special Notations	None noted

Existing Code Language:	(a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions. (b) If a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved; or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with §192.619 (a) and (b).
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	None
Interpretation Summary	Date: 11-01-75 OPS Advisory Bulletin No. 75-11 November, 1975 In determining what measures may be necessary to account for road construction over an existing pipeline, you should consider the types and magnitudes of all anticipated external forces which may be applied to the pipeline during and after the road construction. Various causes of external forces, which you should consider include: unstable soils, floods, traffic, movement by heavy construction or maintenance equipment, and direct damage by construction equipment. If it is decided that a portion of the pipeline should be replaced, relocated, or otherwise changed to protect it against likely external forces, that replacement, relocation, or change must comply with the requirements in applicable design, construction and testing criteria.
Interpretation Summary	Date: 01-26-77 As initiated by loss of pipeline cover, safety standards are enforceable only against persons who own or operate pipelines and do not apply to third parties or outside contractors who may interfere with a pipeline, such as by construction of a roadway. Refusal or inability of persons other than the operator to correct unsafe situations which they have created on an operator's pipeline does not relieve the operator of its responsibility for compliance.
Interpretation Summary	Date: 10-18-89 Regulations allow pipeline operators to use whatever means are suitable to achieve compliance, including aerial video taping. We believe aerial video taping could be an acceptable part of the process of complying with the standards, if appropriately applied by the operator.

Interpretation Summary	Date: 12-01-89 Regulations specify the depth to which a pipeline must be buried at the time of construction. However, when an operator learns that a pipeline is, or has become, unsafe because of potential damage of flooding or a farming activity, it must correct the problem. Remedial action may include lowering the pipeline, adding more cover over the line, or otherwise protecting it against outside force damage.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted
New Guidance Material	- This paragraph addresses the adequacy of an operator=s action (or lack of action) taken to mitigate conditions that are affecting a pipeline facility in a manner that, if unabated, may cause the development of a safety hazard. - If after evaluating all the factors, a determination is made that an immediate hazard exists, refer to the requirements of §§192.615 or 192.703. - The operator must evaluate any loss of cover to determine if an unsafe condition exists. When the operator becomes aware of an unsafe condition, it must take appropriate action to prevent damage in a reasonable time. Such action may be other than restored cover. - A plan must provide for immediate action to recondition, phase-out or reduce the pressure whenever continuing surveillance does not verify line integrity. Actual continuing surveillance procedures can also be included in the various procedures listed below, but must be cross referenced. - §192.613(a) requires surveillance procedures to check for changes in: . Class location (§192.609, §192.611) . Failures (§192.617) . Leakage history (§192.706, §192.723) . Corrosion (§192.455, §192.457, §192.459, §192.483, §192.485, §192.487, §192.489) . Cathodic protection requirements (§192.463, §192.465, §192.467) . Other unusual operating and maintenance requirements (§192.614, §192.705) . Flooding, earthquakes, landslides, snowload, ice, lightning, etc. - Some examples of procedures, which an operator may establish or expand based on site-specific needs (may exceed the minimum code requirements stated elsewhere in the regulations): . Odorization of lines not otherwise required to be odorized . Establishment of "sensitive" areas in close proximity to people, where increased maintenance and surveillance is performed . Leak surveys . Aerial patrols and/or line walking . Monitoring ongoing construction and encroachment activities

	. Monitoring ongoing excavating, mining/quarry work, landfills, etc. . Corrosion surveys . Cathodic protection activities . Programs to recondition or replace pipe over a period of time . Pressure testing . Pressure reduction . Application of non-destructive testing equipment and/or instruments - Separate procedures may be required for each type of facility such as, pipelines, compressor stations, regulating/measuring stations, transmission/distribution systems. - The age of facility or construction type may also be a consideration. - In addition, the type or location, such as rural, suburban, city, road/railroad crossing, unstable right-of-way, construction area, etc., should be considered. - The operator should select corrective or monitoring procedures appropriate for its facilities in its environment. - §192.613(b) requires that each situation identified by surveillance or monitoring be evaluated and that appropriate one time or continuing corrective action be initiated. The action may be the application of a specific regulation, developed by the operator or as recommended by industry guidelines. - Some of the factors to consider in determining compliance are: . Proximity of the public to the pipelines . The probability of a leak . The type of leak expected (seeping mechanical joints corrosion pit, material failure) . Elevated line pressure . Stability of pipeline right-of-way . Potential for underground migration of gas . Age of pipe . Corrosion protection and monitoring system . Loss of cover due to erosion . Encroachment from site development activities . Scour occurring near/under pipeline rip-rap . Issues related to valve operations . Above grade pipe and aerial spans . Extra attention applied to un-pigged line segments . Environmental issues related to slides, earthquakes, floods, hurricanes, etc.
Examples of a Violation	- The operator does not have a surveillance procedure for the appropriate identified factors and/or does not have a plan to respond to the findings. - The operator has not identified a facility as being in unsatisfactory condition. - The operator did not use good judgment in determining a hazard or the potential of a hazard that may develop. - The operator did not take action to correct, or insufficient action was taken to mitigate the identified condition.

Evidence Guidance	- Copy of company surveillance procedures and associated process forms. - Photographs of field locations where surveillance requirements were compromised, that include views of any nearby and noteworthy structures, buildings, highways or construction. - Identification of field locations by station number, mile-pole or other survey-type reference. - Long-term outstanding public complaints about severe soil erosion over pipe, or looming safety hazards. - Rationale for the determination of inadequacy of the action and the nature of the potential hazard and/or the unsatisfactory condition.
Other Special Notations	None noted

Existing Code Language:	(a) Except for pipelines listed in paragraphs (d) and (e) of this section, each operator of a buried pipeline shall carry out in accordance with this section a written program to prevent damage to that pipeline by excavation activities. For the purpose of this section, "excavation activities" include excavation, blasting, boring, tunneling, backfilling, the removal of above ground structures by either explosive or mechanical means, and other earth moving operations. An operator may perform any of the duties required by paragraph (b) of this section through participation in a public service program, such as a "one-call" system, but such participation does not relieve the operator of responsibility for compliance with this section. (b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section. (1) The state has adopted a one-call damage prevention program under Sec. 198.37 of this chapter; or (2) The one-call system: (i) Is operated in accordance with Sec. 198.39 of this chapter; (ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and (iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline. (c) The damage prevention program required by paragraph (a) of this section must, at a minimum: (1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located. (2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program: (3) Provide a means of receiving and recording notification of planned excavation activities. (4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings. (5) Provide for temporary marking of buried pipelines in the area of excavation

	activity before , as far as possible, the activity begins. (6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities: (i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and (ii) In the case of blasting, any inspection must include leakage surveys. (d) A damage prevention program under this section is not required for the following pipelines: (1) Pipelines located offshore. (2) Pipelines, other than those located offshore, in Class 1 or 2 locations until September 20, 1995. (3) Pipelines to which access is physically controlled by the operator. (e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following: (1) The requirement of paragraph (a) of this section that the damage prevention program be written; and (2) The requirements of paragraphs (c)(1) and (c)(2) of this section.
Origin of Code	192-40, 04-01-82
Last FR Amendment	192-84B, 07-20-98
Interpretation Summary	Date: 09-14-88 (August 6, 1976 & No Date Interpretations refer to the same issue) This is not an interpretation, but a response justifying this requirement. OPS believes the rule meets the intent of Congress and the recommendations of NTSB developed over several years of investigations. We do not believe the "actual notification" requirement of ' 192.614(b)(4) should be removed "when no facilities are present" as Michael Kidd suggests. Nor, do we believe that a State should be able to continue with a program which does not require the notification in ' 192.614(b)(4) because such omission would adversely conflict with essential criterion in ' 192.614.
GPTC	Industry guidance available
Other Ref. Material & Source	Date: 08-23-99 Advisory Bulletin ADB-99-04, Directional Drilling and Other Trenchless Technology Operations Conducted in Proximity to Underground Pipeline Facilities.

New Guidance Material	- As specified in Amendment 192-95, 68 FR 69718, an operator must enhance its damage prevention program, as required under ' 192.614 of this part, with respect to a covered segment to prevent and minimize the consequence of a release due to third party or outside force damage. - An operator must have a written program to prevent damage to their pipeline by excavation activities. This may be a separate written program or made part of the operator=s written O&M plan as required by §192.605(a). The written procedures should state the purpose and objectives of the damage prevention program, and provide methods and procedures to achieve them. Applicable state and local requirements should also be noted. (§192.614(a)). - A one-call system or an information service provider may not be able to perform all the tasks required by the damage prevention program. However, an operator may still use these resources to assist in the compliance of this requirement. - The process used to receive and record notifications of planned excavation activities must assure that all notifications are received and recorded. - It is acceptable to use third parties to conduct meetings with excavators on behalf of the operators; however, the operator is ultimately responsible for compliance with this requirement. - Documentation must be kept concerning a good faith attempts, and include who was invited, who attended, and topics discussed. - An operator is ultimately responsible to assure that all of the damage prevention requirements are being performed. - Notification of all excavators who normally operate within the vicinity of the operator=s pipeline may be difficult. It is important that the operator=s process assures that a reasonable effort has been made to identify all excavators. - Operator=s process should include provisions for monitoring ongoing construction and encroachment activities, and monitoring ongoing excavating, mining/quarry work, and landfill operations, etc.
Examples of a Violation	- A written program to prevent damage to a pipeline by excavation activities has not been established as required, omits specific requirements of §192.614(c), or has not been carried out in accordance with the program=s written procedures. §192.614(a) - The operator does not participate in a qualified one-call system (see §192.614(b)(1) or (2)), for receiving and recording notification of planned excavation activities. §192.614(b) - The damage prevention program omits one or more of the required provisions under §192.614(c)(1) thru (6), or lacks sufficient detail for adequate compliance with one or more of those provisions. §192.614(c) - Through spot checking, the operator=s list of identified contractors does not include excavators listed in the current local yellow pages directory, or other excavator listings, who are indicated as working in the area of the pipeline. §192.614(c)(1) - The process by which mailing lists are developed including mailing frequency, or other documentation (meeting attendance records, etc.) demonstrate that a

	reasonable effort has not been put forth to assure actual notification of the identified excavators was carried out. The communication process (mailings, news media, meetings) either has not been implemented or fails to provide sufficient information about the existence and purpose of the operator=s damage prevention program to the public (right-of-way residents or landowners). §192.614(c)(2) - The process used to receive and record notification of planned excavation activities does not have a means to recover from equipment outages, so that no messages are lost. §192.614(c)(3) - The operator has not contacted an excavator who gave notice of their intent to excavate in the area of the pipeline. §192.614(c)(4) - The operator has not provided for temporary marking of buried pipelines in the area of excavation activity before the activity begins, except in emergency situations. §192.614(c)(5) - The operator did not inspect their pipelines in which the operator has reason to believe could have been damaged by excavation activities. §192.614(c)(6)
Evidence Guidance	- Statements from contractors, public, or other persons. - Records supporting non-compliance. - Omission of records to support compliance. - Photographs of improper marking, lack of required marking, excavation damage, etc. - Copy of Damage Prevention Program written plan or specific procedure. - Copy of brochure, letters, news media advertisements indicating communications failed to provide required information to the public. - By admission, records, or lack of records that the operator has not identified (on a current basis) persons who normally engage in excavation activities in the area in which the pipeline is located. - Documentation of meetings, invitation lists, and list of those that attended the meeting.
Other Special Notations	None noted.

Existing Code Language:	(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following: (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator. (2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials. (3) Prompt and effective response to a notice of each type of emergency, including the following: (i) Gas detected inside or near a building (ii) Fire located near or directly involving a pipeline facility (iii) Explosion occurring near or directly involving a pipeline facility (iv) Natural disaster (4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency. (5) Actions directed toward protecting people first and then property. (6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property. (7) Making safe any actual or potential hazard to life or property. (8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency. (9) Safely restoring any service outage. (10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible (b) Each operator shall: (1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures. (2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective. (3) Review employee activities to determine whether the procedures were effectively followed in each emergency. (c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to: (1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency; (2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency; (3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and, (4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

Origin of Code	192-24, 03-31-76
Last FR Amendment	192-71, 02-11-94
Interpretation Summary	Date: 06-17-97 Section §192.615(a)(3)(i) allows operators latitude in responding to notices of gas odor inside buildings. As long as an operator's response is "prompt" and is "effective" in minimizing the hazard, there would be little reason, if any, to challenge the appropriateness of the operator's procedures. Given the pros and cons of taking time in a gas emergency to open windows and doors before exiting, we do not think there is sufficient reason to challenge the effectiveness of a response that tells callers to exit quickly without stopping to open windows and doors.
Interpretation Summary	Date: 02-23-94 Advisory Bulletin ADB 94-03 Pipelines in a common right-of-way, parallel right-of-way, or cross a railroad right-of-way
Interpretation Summary	Date: 02-04-93 This responds to your letter of December 15, 1992, in which you ask us to clarify the requirements in §§192.615(c) and 195.402(c)(12) regarding the requirements to "...establish and maintain liaison with appropriate fire, police, and other public officials..." In complying with §§192.615(c) and 195.402(c)(12), operators must meet face-to-face with public officials and maintain an ongoing face-to-face liaison after the initial meeting.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted

New Guidance Material	- Core emergency plans are fine for the whole company; however, there must be site-specific information about area locations covered by the locally-applied emergency plan. §192.615(a) - Cross references must be included in the emergency plan, if material in other manuals are to be used at the incident site (i.e. Safety Manuals, etc.). §192.615(a) - Individuals who normally receive calls for the operator should be appropriately trained to identify the situation, direct callers to seek safety first, and then gather critical information to promptly initiate the operator=s response efforts. §192.615(a) - It is permissible to have on-line access to an electronic copy of the Emergency Plan; however, appropriate portions of the plan must be readily accessible locally, even if network connectivity to headquarters is temporarily not available. The same is true for maps showing the location of emergency valves and other pertinent information. §192.615(b) - Emergency training programs typically include mandatory initial employee training, with periodic individual refresher training. The operator should require and Atrack@ individual employee training frequencies. §192.615(b) - Emergency training should cover different levels of responsibility and complexity, including, as applicable to the operator, personnel from the control center, managers and/or supervisors, field personnel, patrol pilots, communications systems, SCADA systems, etc. §192.615(b) - Emergency exercises are not mandatory but are recommended. They may include Atabletop@ scenarios, on-scene Amock@ and/or corporate-wide exercises, simulated control room exercises, etc. §192.615(b) - One method operators use to review performance, make appropriate changes, and verify that supervisors maintain a thorough knowledge, is by critiquing the performance of emergency exercises. All simulated and real emergencies should be self-critiqued, with deficiencies identified and recommendations made and followed up on. §192.615(b) - It is acceptable to use third parties to conduct meetings with appropriate public officials on behalf of the operators; however, the operator is ultimately responsible for compliance with this requirement. §192.615(c) - Documentation must be kept concerning a good faith attempt, and include who was invited, who attended, and topics discussed. §192.615(c) - Appropriate materials must be sent to the public officials that were invited but did not attend. §192.615(c) - The operator should make reasonable attempts to conduct face-to-face meetings with local public officials. §192.615(c)

Examples of a Violation	- Statements indicating that they treat all incidents as emergencies and have no provisions for prioritizing multiple events that could occur at the same time. - No listing of where pretested emergency pipe is located. - No listing for the railroad road-master or individual with the authority to shut-down a segment of a railroad that parallels a pipeline in their assigned area. - Maps that have not been revised or red lined to show modifications to essential facilities, as in removal or addition of emergency valves. - Control displays or other aids that have not been revised to show modifications to essential facilities, as in removal or addition of emergency valves. - Lack of training related to emergency response. - A written, continuing training program has not been established. - Training program procedures are/have not been followed. - No documentation of the required review of emergency procedures used during recent emergencies. - Omission of invitations for certain public officials for liaison meetings. - Insufficient documentation of the materials sent or provided to public officials about liaison meetings. - No documentation of attempts to meet with appropriate public officials. -The procedure parrots the regulation.
Evidence Guidance	- Copy of emergency procedures or applicable portion that shows omission or deficiency in the plan. - Documented conversations with operator personnel who are charged with establishing the plan. - Documentation of meetings, invitation lists, and list of those that attended the meeting.
Other Special Notations	None noted

Existing Code Language:	(a) 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 (IBR, see § 192.7). (b) The operator's program must follow the general program recommendations of API RP 1162 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, 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 small propane distribution systems having less than 25 customers and master meter operators having less than 25 customers must have completed development and documentation of their programs no later than June 20, 2007. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency. (i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.
Origin of Code	192-24, 03-31-76 (Previously part of §192.615(d))
Last FR	192–100, 195–84, May 19, 2005

Amendment	

GPTC	Industry guidance available.
Other Ref. Material & Source	Dig Safely, National Campaign
Other Ref. Material & Source	API 1162, Public Awareness Programs for Pipeline Operators, currently referenced edition, see §195.3.
New Guidance Material	**Note to Inspectors: The review of operator's WRITTEN public awareness programs will be a function of A CLEARINGHOUSE ESTABLISHED BY PHMSA HQ in Washington DC. Inspectors should focus on determining if an operator's program was in effect on or before the dead lines listed above. Additionally Inspectors should review public awareness program implementation documentation to determine if the operator is following through on the provisions listed in their WRITTEN public awareness program.** By June, 20, 2006 the operator of a natural gas transmission pipeline or distribution system must have a written program 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 that follows the guidance given in API 1162. Operators of small propane distribution systems and master meter systems with less than 25 customers must have a public awareness program by June 20, 2007. PUBLIC AWARENESS PROGRAM PROVISIONS: **Note: the following is a general compilation of the requirement of both API 1162 and §192.616. For further clarification and descriptions API 1162 should be referenced.** STAKEHOLDER AUDIENCE: A written public awareness program must include provisions to educate: (1) The Affected Public (all residents, municipalities, school districts, churches, businesses and other places of congregation near either the transmission pipeline ROW or near pipeline facilities), periodically (API 1162 advises every 2 years), through means of printed materials and if appropriate personal contacts, telephone calls, group meetings, and/or open houses. (2) Emergency Officials (local, state, or officials, agencies and organizations with emergency response or public safety jurisdiction along the pipeline route including pipeline facilities), periodically (API 1162 advises annually), through means of personal contacts (preferred), targeted distribution of printed materials, group meetings, or telephone calls with targeted distribution of print materials and if appropriate emergency table top deployment exercises, facility tours, and/or open

houses.

(3) Public Officials (local, city, county, state, or federal officials and their staffs having land use and street/road jurisdiction along the pipeline route including pipeline facilities), periodically (API 1162 advises every 3 years), through means of targeted distribution of print materials and if appropriate personal contacts, telephone calls, and/or videos and CDs.
(4) Excavators/Contractors (companies and local/state/federal government who are involved in any form of excavation activities), periodically (API 1162 advises annually), through means of targeted distribution of print materials and one call outreach and if appropriate personal contacts and/or group meetings.
(5) Land Developers (companies and private entities involved in land development and planning), at frequencies that are appropriate, through means of targeted distribution of print materials, personal contact, group meetings, and/or telephone calls.
(6) Membership in the appropriate One-Call Center, at frequencies required by the applicable One Call Centers, requirements of the applicable One-Call Center and all maps as required by the appropriate One-Call Center. As pipeline routes change additional targeted distribution of print materials, personal contacts, and/or telephone calls should be made.

The written program must include methods and frequencies for delivering the following messages at the level of detail appropriate for each audience unless the operator provides justification as to why one or all messages would not be practicable and not necessary for safety.

BASELINE MESSAGES:

To the Affected Public, Emergency Officials, Public Officials, Excavators/Contractors, and Land Developers

(1) Pipeline and/or Facility Purpose and Reliability
(2) Potential Hazards and Prevention Measures
    a. Specific information about release characteristics and potential hazards posed by the accidental release of the substance from the pipeline and/or pipeline facility.
    b. Preventative measures undertaken by the operator in planning, design, operation, maintenance, inspection and testing of the pipeline. Should reinforce how the audience can play an important role in preventing third-party damaged and right of way encroachments.
(3) Leak Recognition and Response
    a. Recognizing a Pipeline Leak by sight, sound, and or smell.
    b. Response to a Pipeline Leak
        i. What to do and what not to do if a leak is suspected (including specific information on detection response if the pipeline contains product that, when released, could be immediately hazardous to health (e.g. high concentration of hydrogen sulfide).
        ii. How to report a leak.

(4) Pipeline Location Information
   a. Maps appropriate to the audience.
   b. Transmission pipeline markers, how to identify them, what information is on them and a statement that the markers merely indicate the pipeline ROW and not necessarily the exact pipeline location.
   c. How to get additional information and the availability of pipeline operators in the area through NPMS.

To the Affected Public, Public Officials, and Excavators/Contractors.
(1) Damage Prevention (the importance to report any suspected signs of damage consistent with the key "Dig Safely" messages developed by the Common Ground Alliance).
(2) Use of One Call Notification System (the appropriate One Call System phone number and a request to call the One Call System in their area before they begin any excavation activity. If the state or locality has established penalties for failure to use established One Call System, that fact may also be communicated, depending on the audience and situation).

To Emergency Officials and Local Public Officials.
(1) Emergency Preparedness Communications
   a. Operator considers public safety and environmental protection as top priorities in any pipeline emergency response.
   b. Emergency 24 hour contacts and phone numbers, ensuring that both the operator and emergency officials have current phone numbers and calling priorities.
   c. The operators Emergency Response Plan.
   d. Information on the unified command system, roles, operating procedures, and preparedness for various emergency scenarios through hands on drills and exercises.

To One-Call Centers.
(1) Membership in the appropriate One-Call Center.
(2) Requirements of the applicable One-Call Center.
(3) All maps as required by the appropriate One-Call Center.
(4) As pipeline routes change additional targeted distribution of print materials, personal contacts, and/or telephone calls should be made.

SUPPLEMENTAL MESSAGES:

Supplemental messages at appropriate frequencies as listed in API 1162 to:
(1) The Affected Public, information about the operator's Integrity Management Program, right-of-way encroachment prevention, any planned maintenance and or construction activity, special response notification and or evacuation measures if appropriate to the product or facility, and facility, i.e. tanks etc., propose.
(2) Emergency Officials, information about the operator's Integrity Management

	Program and any construction activity. (3) Local Public Officials, information about HCA designations and summaries of integrity measures undertaken by the operator, ROW encroachment prevention, and maintenance and construction activity. (4) Excavators, information about the pipeline purpose, prevention measures and reliability. (5) Land Developers, information about the pipeline purpose and reliability, awareness of hazards and prevention measures undertaken, Damage Prevention Awareness, One-call requirements, leak recognition and response, ROW encroachment prevention, and the availability of lists of pipeline operators through NPMS. (6) One-Call Centers the One-Call performance, accurate line location information, and one-call system improvements. SPECIAL CONSIDERATIONS: Operators should consider widening the public awareness program coverage area for: ▪ HVL pipelines in high population areas. The coverage area should be extended beyond the 1/8th mile minimum distance on each side of the pipeline. The coverage area should be extended as appropriate based on a sound engineering analysis which should include as a minimum, topography, worst case spill volume, and any other applicable considerations. ▪ Large diameter, high pressure, high volume pipelines where a pipeline emergency would likely affect the public outside the specified minimum coverage area. The coverage area should be extended to a wider distance as deems prudent PROGRAM EVALUATION: The written program must have a plan to evaluate the implementation and effectiveness of their public awareness program. DOCUMENTATION: The operator must have documentation showing implementation and the evaluation of their public awareness program. Both the implementation and the evaluation must in compliance with their public awareness program.
Examples of a Violation	- An operator has not established, or followed its public awareness program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials. - A written public awareness program completed after June 20, 2006, or in the case of small propane and master meter systems (less than 25 customers) after June 20, 2007. - An operator has not met the time frames shown in their public awareness program. - The program and the media used do not reach all areas in the operator=s area. - The program is not conducted in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

	- Operator did not collect and retain documentation to demonstrate compliance.
Evidence Guidance	- Lack of a written public education program. - Documented date of an operators initial public awareness program. - Documented conversations with operator. - Sign-in sheets for attendees of emergency agencies facility tours. - Records and documentation of the frequency or specific media employed. - Statements and/or documents from the public, appropriate government organizations, and/or excavators which indicate they have not received the required information. - Local newspapers, radio/TV, and business communications demonstrating a significant use of non-English language in the area.
Other Special Notations	None noted

Existing Code Language:	Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.
Origin of Code	08-19-70, Original Code Document
Last FR Amendment	None
Interpretation Summary	Date: 06-16-92 Summary: The Appendix D criteria were based on the National Association of Corrosion Engineers (NACE) Standard RP-01-69 and Appendix D will not be dropped to adopt instead a system-specific approach. Determining the cause of each corrosion leak is covered by §§192.617, 193.2515, and 195.402(c) and operators with numerous corrosion leaks should be asked to explain their actions or lack of action, but the rules needed to require operators to take proper corrective actions are already in the regulations.
GPTC	Industry guidance available
Other Ref. Material & Source	None noted
New Guidance Material	- A procedure must be prepared for selecting, collecting, preserving, labeling, site-mapping and handling specimens; to include a chain-of-custody process with associated records. - A detailed analysis, including root cause and trending of incidents, should be performed. - When a detailed analysis is to be made, a person at the scene of the incident should be designated to coordinate the investigation. That person's minimal responsibilities should be listed in the operator=s procedures. - When a detailed analysis is to be made, a fully qualified investigation team should be designated. The team=s minimal objectives should be listed in the operator=s procedures. - A photographic record of the scene is typically a valuable resource, and should include views from all angles. - Photo records should include compass orientation and a brief description of captured objects. - Specific procedures for collecting metallurgical specimens should include precautions against changing the granular structure in the areas of investigatory interest.

	- Operator should have an adequate process to address and conduct post-accident drug and alcohol testing.
Examples of a Violation	- Operator failed to establish procedures for analyzing accidents and failures for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence. - The operator=s procedures do not provide detailed guidance that directs how to conduct an investigation.
Evidence Guidance	- Operator=s procedures and related forms. - Records and documentation of failure investigations. - Documented statements from the Operator. - Operator=s incident reports. - Results of drug and alcohol testing. - Operator=s event log.
Other Special Notations	None noted

Existing Code Language:

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

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under '192.14 or up-rated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula ('192.105) is unknown, one of the following pressures is to be used as design pressure: (i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or (ii) If the pipe is 12: inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.

(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 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Factors * segment

Class location	Installed before (Nov 12, 1970)	Installed after (Nov 11, 1970)	Converted under '192.14
1	1.10	1.10	1.25
2	1.25	1.25	1.25
3	1.40	1.50	1.50
4	1.40	1.50	1.50

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

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970 (or in the case of offshore gathering lines, July 1, 1976), unless the segment was tested in accordance with paragraph (a)(2) of this section after July 1, 1965 (or in the case of offshore gathering lines, July 1, 1971), or the segment was up-rated in accordance with Subpart K of this part.

(4) 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)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with '192.195

	(c) Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding July 1, 1970, or in the case of offshore gathering , July 1, 1976, subject to the requirements of '192.611.
Origin of Code	08-19-70
Last FR Amendment	192-85, 07-13-98
Interpretation Summary	Date: 06-04-71 It is our opinion that pipelines in Class 2, 3, and 4 locations must have their operating pressures confirmed or revised in accordance with section §192.611. However, pipelines in Class 1 locations operated at pressures which are not commensurate with that class location, based on the design stress levels of section §192.619(a)(1), may continue to operate at their previous MAOP under the "grandfather" clause of section §192.619(c).
Interpretation Summary	Date: 09-16-82 The "desired maximum pressure" of facilities is not defined or specifically regulated by Part 192. However, the operating pressure of a pipeline may not exceed its maximum allowable operating pressure (§192.619, 192.623) or any lower pressure that might be required as a remedial measure for safety (e.g., '192.485).
Interpretation Summary	Date: 08-04-86 Q. Is it the intent of the regulations that the pressure gradient be ignored in determining the MAOP and that the MAOP for the entire line from A to B be established at 850 psi? A. No, the intent of §192.619(c) is to allow old safe operations to continue, but not be exceeded. Thus, pressure gradient would have to be continued. The MAOP of an element inside the segment could not exceed its old operating pressure. Q. As an inspector, must I verify that the entire line from A to B was subjected to 850 psi sometime during that five year period? A. Yes Q. Is it adequate to assume that it was because the line was frequently operated at a

	discharge pressure of 850 psi at A? A. No Q. Do the regulations require that the operator have records to substantiate the pressures used to establish the MAOP per 192.619(c)? The regulations do not require "records", however, enforcement personnel have to apply judgment as to what they will accept to substantiate the operator claim. A violation would have to be clearly obvious in order to be enforceable. Records (i.e., pressure recording charts, compressor station records, flow calculations from a substantiated point, dispatcher records, etc.), sworn statements by the operator, etc., would be means that the operator could use to establish the highest pressure for the 5 year period.
Interpretation Summary	Date: 06-12-96 §192.619(a)(2)(ii) permits operators to rely on previous test pressures in calculating MAOP. And there is nothing in the regulations that alters this policy when MAOP is determined by up-rating.
GPTC	Industry guidance available.
Other Ref. Material & Source	Date: 04-22-98 Transportation Safety Institute - Determination of Maximum Allowable Operating Pressure in Natural Gas Pipelines.
New Guidance Material	- §192.619 is used to determine MAOP of a specific pipeline segment. - An operator must have some means that will ensure that the MAOP is not exceeded during normal operations. - The intent of §192.619(c) (grandfather clause) is to allow old safe pipeline segments to continue operating at a specified pressure which will not be exceeded during normal operation. - MAOPs based on MP5 pressure gradients may still apply. As an example, the MP5 pressure at the discharge side of compressor station A may be greater than the MP5 pressure at the suction side of compressor station B. In this case, established MAOP=s along a segment or section may differ. The guiding principal is that the MAOP of an element inside the segment cannot exceed it=s old (MP5) operating level. - A grandfathered, (§192.619(c)), MAOP in a class 1 area is voided when the pipeline segment class change occurs, unless the segment hoop stress is commensurate with the new class location. - Pipelines that are located in Class 2, 3 and 4 locations, regardless of when placed in service, cannot operate above the hoop stress that is commensurate with the

	present class location, unless the MAOP has been confirmed or revised (or is being confirmed or revised due to a recent class location change) in accordance with §192.611. In other words, these segments were not Agrandfathered@ from the requirements of §192.611. - Operators may not design or set normal pressure controlling devices such that any part of any pipeline segment exceeds its prescribed MAOP. - Operators may not exceed MAOP for such purposes as temporarily applying a pressure boost in an attempt to dislodge a stuck pig, during times of high demand rates, or other operational upset conditions. - §192.619(a)(2)(ii) permits operators to rely on previous test pressures in calculating MAOP. And there is nothing in the regulations that alters this policy when MAOP is determined by up-rating. - The "desired maximum pressure" of facilities is not defined or specifically regulated by Part 192. However, the operating pressure of a pipeline may not exceed its maximum allowable operating pressure (' 192.619, §192.623) or any lower pressure that might be required as a remedial measure for safety (e.g., ' 192.485).
Examples of a Violation	- Operator=s listed MAOP exceeds the criteria of §192.619. - All applicable elements required in a MAOP calculation were not adequately documented. - Actual operating pressure exceeded MAOP, without the occurrence of an equipment malfunction or failure. - Operator has no means to prevent the pipeline from being normally operated above the MAOP.
Evidence Guidance	- Records used to substantiate MAOP, such as: . MP5 records . Up-rating records . Hydro-test records . Pipe and component specifications . Segment class designations. - Diagram of the system showing existing pressure-limiting devices. - Photographs of field equipment. - Segment operating pressure records (charts and SCADA printouts).
Other Special Notations	None noted

Existing Code Language:	(a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell. (b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless: (1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location; (2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975: (i) An underground storage field; (ii) A gas processing plant; (iii) A gas dehydration plant; or (iv) An industrial plant using gas in a process where the presence of an odorant: (A) Makes the end product unfit for the purpose for which it is intended; (B) Reduces the activity of a catalyst; or (C) Reduces the percentage completion of a chemical reaction (3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or (4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process. (c) In the concentrations in which it is used, the odorant in combustible gases must comply with the following: (1) The odorant may not be deleterious to persons, materials, or pipe. (2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed. (d) The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight. (e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant. (f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by - (1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and (2) Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.
Origin of Code	Original Code Document, 08-19-70

Last FR Amendment	192-93, 09-15-03, Effective date 10/15/03
Interpretation Summary	Date: 12-17-70 Answer: In §192.625(f), the term "periodic sampling" is used instead of requiring a specific amount of time between tests, because each system will have different requirements. The operator must sample as often as experience indicated the need, to assure proper odorant level.
Interpretation Summary	Date: 10-31-73 §192.625(f) - The gas operator must test its system sufficiently to assure compliance with this requirements. The number, location, and frequency of this sampling can best be determined by the operator, based on the experience and characteristics of the particular gas system. Some consideration in determining the sampling period would be the location, size of the system, age of the system, average number of annual leaks in the system, any new lines in the area of the sampling, type of pipe in the area of sampling, past experience in odorization sampling, type of odorant used, and any other factors that could effect the ability of the gas to maintain the required odorant level.
Interpretation Summary	Date: 02-14-74 A regular check of the injection rate of the odorant into the gas is a good indicator that the desired level of injection is being maintained at the odorizer. This does not determine that there is a sufficient odor level throughout the system. Odorant, under certain conditions, will drop out of the gas within a piping system; thus, there can be excessive odorant in some areas and not enough in other areas at the same time. This could cause "odorant complaints" in one part of the gas system while some areas would be receiving insufficient odorant in the gas. Odorant is often lost from the gas due to the effect of dirt in the system, velocity of flow precipitation of odorant on the walls of new pipe installed and low humidity of the gas stream, to list a few influences. The various odorants used in gas distribution also vary widely in their strength; therefore, the amount of odorant that should be injected in a given volume of gas cannot be given as one number for all odorants.

Interpretation Summary	Date: 02-06-79 (The 18 month requirement has been changed to 24 months under the current revision to §192.611). This is in response to your recent letter asking how much time is permitted under Part 192 to make system changes (in particular odorization) necessitated by class location changes. While §192.613(a) requires an operator to make necessary changes, no time period for compliance is specified. However, a similar provision under §192.611(c) requires confirmation or revision of MAOP within 18 months after a change in class location. In view of this similarity, it appears that an 18-month compliance period is appropriate to apply under §192.613(a). In a previous interpretation, we have stated that the 18-month period begins to run upon completion of a structure which results in a new class location. (See §192.611 interpretation of 05-12-78)
Interpretation Summary	Date: 03-03-79 On odorizing equipment that is not equipped to measure the injection rate or the volume of odorant in the odorizer tanks, the tanks would at least have some means of indicating when they are full. An operator can determine the number of pounds of odorant required to fill the odorizer tanks and by reading the gas meter determine the quantity of gas used since the odorizer was last filled. From this, the pounds of odorant per million cubic feet of gas can be determined and compared with other periods. Filling of odorizers and reading of gas meters should be often enough to assure continuous odorization of gas delivered and should be done, in so far as is practicable, near the times when the system gas load characteristics are expected to change. These changes should be readily anticipated by operators having knowledge of the customer gas usage characteristics and at seasonal or other weather changes such as extreme cold weather.
Interpretation Summary	Date: 09-10-80 A farm tap from a transmission line is used to deliver gas to a restaurant directly from a transmission line. Gas in the transmission line is not required to be odorized. Does the gas in the service line have to be odorized? §192.625(a) requires that gas in distribution lines have a natural odor or be odorized to the limit prescribed. Since service lines are distribution lines, they are subject to the odorization requirements of §192.625(a). The exception from odorization provided by §192.625(b) for some transmission lines does not affect the requirement to odorize gas in distribution lines connected to an unodorized transmission line.

Interpretation Summary	Date: 03-11-82 If there are 30 other customers along the pipeline not requiring unodorized gas, does the one which requires unodorized gas govern the determination? Any of the customers along an unodorized transmission line that receive gas via a service line would have to be supplied odorized gas under §192.625(a).
Interpretation Summary	Date: 06-07-89 Section 192.9, Gathering Lines, requires each gathering line to comply with the requirements of Part 192 applicable to transmission lines. In addition, §192.625(b)(1) exempts from odorization requirements transmission lines in Class 3 or 4 locations where at least 50 percent of the downstream length of line is in Class 1 or 2 locations.
Interpretation Summary	Date: 07-23-92 Any testing procedure may be used that is capable of demonstrating the sufficiency of odorant concentration. If a gas chromatograph is used, the operator must compare the measured odorant concentrations with the proper concentration, which must be determined separately. Since the proper odorant concentration can vary among systems, we cannot give you a specific value in lbs./MMCF that meets the standard.
GPTC	Industry guidance available.
Other Ref. Material & Source	Transportation Safety Institute, Odorization Papers.
New Guidance Material	- Any combustible gas in a transmission line that is odorized, must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell. - Sniff tests are qualitative tests that should be performed by individuals with a normal sense of smell, considering smoking habits, colds, and other health-related conditions that could affect the sense of smell. Such tests should be conducted by releasing small amounts of gas for short duration in a controlled manner to determine whether odorant is detectable. Records should reflect the person actually doing the sniff test. - Some operators conduct sniff tests with two individuals, to get more conclusive results. - Test locations to verify odorant levels should include system end points (extremities). - The operator should retain records of the odor level and odorant concentration test results. - Special attention to odorization requirements should be applied to transmission

	(and transmission laterals) lines where class 3 areas exist. - Operator=s line designation plan may help in the determination of line classification of transmission or lateral.
Examples of a Violation	- The operator is not odorizing a pipeline segment that has to be odorized. - The odorant is not detectable as per §192.625(a) at the one-fifth of the lower explosive limit of the gas, or is injected without wide variation. - The operator is odorizing a pipeline, but the odorant is deleterious to persons (materials or pipes) in violation of §192.625(c)(1). - The operator is odorizing a pipeline but, the products of combustion from the odorant are toxic when breathed. - The operator is odorizing the pipeline, but the products of combustion from the odorant are corrosive or harmful. - The operator is odorizing a pipeline and is using up the remnants of a batch of odorant which, laboratory test records show is soluble in water to an extent greater that 2.5 parts to 100 parts by weight in violation of §192.625(d). - The operator is odorizing a pipeline but, the amount of odorant induced by the odorizer varies considerably over time and is inconsistent, in violation of §192.625(e). - The operator is odorizing a pipeline but company records do not substantiate that the operator is conducting periodic sampling of the combustible gas to assure the proper concentration of odorant in accordance with §192.625(f).
Evidence Guidance	- Operator=s procedures. - Records and documentation of odorizer inspections, calibrations, or tests. - Operator=s field checklists or procedures used for operating an odorizer. - Documented statements from operator.
Other Special Notations	None noted

Existing Code Language:	Each tap made on a pipeline under pressure must be performed by a crew qualified to make hot taps.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	None
Interpretation Summary	None provided
GPTC	Industry guidance available
Other Ref. Material & Source	Advisory Bulletin, ALN-87-01, 03-13-87 Recommended Low Hydrogen for Fillet Welds
Other Ref. Material & Source	API RP 2201 Safe Hot Tapping Practices in the Petroleum & Petrochemical Industries
New Guidance Material	- Whenever an operator makes a tap on a pipeline under pressure (hot tap), it must be performed by an individual qualified to make hot taps. - Qualification must be available and supported by appropriate records or equivalent documents. - UT examination of pipe wall should be performed to identify possible laminations, wall thinning or other defects, prior to selecting final tap location. - Pressure testing and NDT of the welded fitting should be performed to ascertain the integrity of the weld, prior to tapping the carrier pipe. - It is acceptable for an operator to use the procedures as provided by the hot tap equipment manufacturer, as long as an associated reference is in the operator=s procedures.
Examples of a Violation	- The operator performed (or contracted) hot taps on a pipeline under pressure using a crew or individual that was not qualified to make hot taps.
Evidence Guidance	- Sections of the operator=s procedures. - Records and documentation of pipeline repairs that required hot taps. - Operator statements. - Photographs. - Qualification records.
Other Special Notations	None noted

Existing Code Language:	(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas. (b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	None
GPTC	Industry guidance available.
Other Ref. Material & Source	AGA XK0101, APurging Principles and Practice@
New Guidance Material	- The operator should determine the time required to complete the purge operation to assure that gas-air mixtures are minimized. - Instruments may be used to verify completion of purge. - Selection of gas venting location should not be near electric high voltage lines, or other overhead obstructions.
Examples of a Violation	- The gas/air was not released into the line in a moderately rapid and continuous flow, resulting in the formation of a hazardous mixture. - The gas/air was not supplied in sufficient quantity, resulting in the formation of a hazardous mixture.
Evidence Guidance	- Operator=s procedures. - Records and documentation of any pipeline purging operations. - Operator field checklists or procedures used during purging operations. - Documented statements from operator.
Other Special Notations	None noted

Existing Code Language:	(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart. (b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. (c) Hazardous leaks must be repaired promptly.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	None
Interpretation Summary	Date: 04-22-74 Hazardous leaks must be repaired promptly and many leaks could lead to a pipeline having to be replaced, repaired, or removed from service.
Interpretation Summary	Date: 05-29-75 Under the circumstances of a pending road construction, the Federal gas pipeline safety standards in §§192.613 and 192.703(b) require that the pipeline be evaluated for safety and appropriate remedial or protective measures taken, if necessary, in accord with those sections. In determining what measures may be necessary, you should consider the types and magnitudes of all anticipated external forces which may be applied to the pipeline during and after the road construction. Various causes of external forces which you should consider include: unstable soils, floods, traffic, movement by heavy construction or maintenance equipment, and direct damage by construction equipment.
Interpretation Summary	Date: 02-10-83 §192.703(b) states that each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service. This requirement applies to all pipeline segments, regardless of the construction date.
Interpretation Summary	Date October 3, 1989 Q1.A. Clarify whether or not the code requires the operator to periodically verify that all connected gas utilization equipment is properly adjusted. A1.A. As discussed above, the design requirements do not make gas operators responsible for subsequent changes that are beyond their control. This, although the operator has to meet the requirements of §192.195 in designing a customer service, the operator does not have to monitor the customer's equipment to verify the continuing appropriateness of the design. However, if an operator learns that its system is creating an unsafe condition, it must take appropriate action under §192.703(b).

Interpretation Summary	Date May 22, 1998 The only safety standard in Part 192 that governs the maintenance of service line valves is §192.703(b). This section requires the repair, replacement, or removal from service of any segment of pipeline, including a valve, that is unsafe. Although the inability to operate a service line valve may be reason to apply §192.703(b), Part 192 does not require inspection of service line valves to see if they are operable.
Interpretation Summary	Date: 06-10-03 (The Gas Integrity Management rule, 192 Subpart O, should be consulted for additional information on repairs). General pipeline facility repair requirements in 49 CFR 192.703 require repair of conditions that are "unsafe" or "could adversely affect the safe operation of [the] pipeline system," but do not specify a time period in which the required repairs must be made. These provisions, instead, require an operator to take actions necessary to assure the pipeline is safe and to take these actions "within a reasonable time." Thus, for the non immediate hazard conditions, a reasonable repair time allows for an operator to obtain the Federal, state or local permits necessary to make a repair. RSPA/OPS expects an operator to exercise diligence in obtaining the necessary permits by being able to demonstrate that it has applied for the applicable permit and is taking all necessary steps for the permit to be processed and granted. In this interim period until the permit is granted, an operator is allowed to take alternative actions to mitigate the condition, as long as the actions are compatible with pipeline safety.
GPTC	Industry guidance available
Other Ref. Material & Source	Advisory Bulletin ADB 99-01, Potential Failure Due to Brittle-Like Cracking Certain Polyethylene Plastic Pipe Manufactured by Century Utility Products Inc.
New Guidance Material	- Operators are expected to identify, evaluate and react to potentially hazardous conditions. - §192.703(a) is usually coupled with other regulations during enforcement actions. - §192.703(b) is frequently associated with §§192.613 and 192.614. - Enforcement should be sought only when the investigator is convinced that corrective action was unreasonably delayed.

Examples of a Violation	- A hazardous leak is not repaired promptly. - A protracted period during which the operator did not react to an identified unsafe condition. - An unsafe condition is not considered prior to a failure.
Evidence Guidance	- Documentation that leak was not repaired promptly, including operator's records showing date of leak discovery and date of repair or operator's or investigator's statement that leak has not been repaired. - Accident investigation reports. - Patrolling records. - Photographs of unsafe conditions. - Operator=s listing of exposed pipe locations.
Other Special Notations	None noted

Existing Code Language:	(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation. (b) The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors, but intervals between patrols may not be longer than prescribed in the following table: Maximum interval between patrols Class location of line / At highway and railroad crossings / At all other places 1,2.......... 7 1/2 months; but at least twice each calender year / 15 months; but at least once each calender year 3............ 4 1/2 months; but at least 4 times each calender year / 7 1/2 months; but at least twice each calender year 4............ 4 1/2 months; but at least 4 times each calender year / 4 1/2 months; but at least four times each calender year (c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.
Origin of Code	Original Code Document, 8-19-70
Last FR Amendment	192-78, 06-06-96 (includes aerial patrols as an optional method of compliance for clarification)
Interpretation Summary	Date: 10-18-89 Opinion that aerial video taping would be an acceptable part of the process of complying with the standards.
Interpretation Summary	Date: 05-28-91 The regulations do not require that trees be removed or that rights-of-way be inspected from the air. It is the position of the Department that, if visual aerial inspections are used by the operator to meet the requirements of the regulations, the rights-of-way must be kept clear of brush and trees. Normally, this is a matter subject to negotiation in the rights-of-way agreement between the pipeline companies and the landowners involved.
GPTC	Industry guidance available.

Other Ref. Material & Source	None
New Guidance Material	- The patrol program to observe surface conditions on and adjacent to the transmission line ROW for indications of leaks, construction activity, and other factors affecting safety and operation should include the following: . Indication of leaks may include dead vegetation, blowing gas & debris, product, sheen or bubbles on the water, and/or odor. . Indication of construction activity may include clearing of trees or vegetation, heavy equipment including directional drilling on or near the ROW . Dredging activities on a waterway in the ROW crossing vicinity, a building, fence or shed, on or near the ROW. . Presence of a coffer dam or bell hole on the ROW, or the presence of marking flags, ribbon, or paint on or near the ROW. . Areas of continual earth moving activities (i.e. gravel/sand pits, quarries, land fills, etc.) . Pipe spans, bank or shoreline erosion at water crossings, removal of rip rap. . Land slides, flooding, exposed pipe. . Dumping or burying of trash on ROW. . Damaged or missing pipeline markers. . If aerial patrols are used, trees or vegetation obscuring the ROW. - Aerial Patrols should take into consideration factors that affect the ability to adequately observe the pipeline ROW such as angle of sunlight, and shadows cast on the ROW that would conceal signs of leakage.
Examples of a Violation	- The frequency of patrols is inadequate as determined by the size of the line, operating pressures, class location, terrain, weather, and other relevant factors. - A transmission line is not patrolled at least as frequently as required by the table. - For aerial patrols, tree canopy and vegetation overgrowth not adequately trimmed, inhibiting the ability to evaluate surface conditions. - When the route of a surface patrol does not provide adequate observation of the ROW. - The patrol program fails to promptly communicate critical patrol intelligence to assure the safety and operation of the pipeline. - Inadequate documentation of patrol follow-up activities, including dates.

Evidence Guidance	- Documentation showing that the pipeline is a transmission line, including operator's records, FPC/FERC certification, photograph, description by investigator, etc. - Documentation showing the class location for transmission line segments, including operator's records, photograph, description by investigator, etc. - Documentation showing whether the pipeline is at highway, waterway or railroad crossing, including operator's records (maps), photographs, description by investigator, etc. - Documentation showing that patrols were not made at required intervals, including operator=s records of inspection kept to show adherence to O&M plan kept pursuant to §192.603(b) and operator's record of patrol kept pursuant to §192.709. - Documentation showing that patrols were not made at more frequent intervals than required as determined by usual operating conditions affecting the safety and operation of the pipeline. - Documentation or lack thereof, including pictures that conditions existed on the pipeline ROW that may adversely affect the safety and operation of the pipeline that were not identified during the patrol. - Patrolling and associated follow-up records.
Other Special Notations	None noted

§192.706	**Transmission Lines: Leakage Surveys**

Existing Code Language:	Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted- (a) In Class 3 locations, at intervals not exceeding 7 2 months, but at least twice each calendar year; and (b) In Class 4 locations, at intervals not exceeding 4 2 months, but at least four times each calendar year.
Origin of Code	192-21, 05-09-75
Last FR Amendment	192-71, 02-11-94
Interpretation Summary	Date: 04-03-01 The DOT pipeline safety regulations at 49 CFR '192.706 and '192.723 only require that leakage be conducted "using leak detector equipment" and is not limited to the use of flame ionization. Leak detection regulations are performance based meaning, that any equipment capable of detecting all leaks in gas distribution or transmission systems may be used. The regulations do not mandate the use of any specific type of detection equipment.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted
New Guidance Material	- Leak surveys must be performed by qualified personnel. - Leak detection equipment must be calibrated. - Records should indicate each facility surveyed, the survey date, the person who conducted the survey, and the survey result. - Surveys must be performed and recorded on all required Transmission Pipelines (including pipe, valves, above ground facilities and appurtenances, meter stations, etc. - including those that are off the main pipeline ROW. (See Pipeline definition under §192.3). - Records should indicate the survey method (vegetation, leak detector equipment, aerial, foot, etc.), and the type/model of any leak detection equipment used. - Inspector should compare Operator=s class location lists and class change records with leak survey records, to verify that any required class 3 or 4 leak detection equipment surveys are being conducted. -Vegetation surveys are permitted in Class 1 & 2 areas or where Class 3 & 4 areas are odorized. - Leak detection equipment is not required for Class 1 & 2.

Examples of a Violation	- Required (§192.706) leak surveys, including gas detector equipment surveys on unodorized class 3 or 4 pipelines, have not been conducted. - Required surveys have not been conducted within the prescribed time intervals. - Required surveys are/have been inadequately conducted. - Evidence of leaks that were not discovered by recent surveys.
Evidence Guidance	- Leak survey records/reports. - Documented statements from the operator. - Type of leak detection equipment. - Leak detection equipment calibration . - Leak detection equipment operating manual.
Other Special Notations	None noted

Existing Code Language:	(a) Buried pipelines. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line: (1) At each crossing of a public road and railroad; and (2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference. (b) Exceptions for buried pipelines. Line markers are not required for the following buried pipelines: (1) Waterways and other bodies or water. (2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under ' 192.614. (3) Transmission lines in Class 3 or 4 locations until March 20, 1996. (4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical. (c) Pipelines above ground. Line markers must be placed and maintained along each section of a main and transmission line that is located above ground in an area accessible to the public. (d) Marker warning. The following must be written legibly on a background of sharply contrasting color on each line marker: (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 1 inch (25 millimeters) high with 3 inch (6.4 millimeters) stroke. (2) The name of the operator and telephone number (including area code) where the operator can be reached at all times.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-85, 07-13-98
Interpretation Summary	Date: 06-20-79 §192.707(a) provides that each pipeline marker that is required to be installed must be "maintained". Although specific criteria for maintenance are not set forth, under this general maintenance requirement, markers must be kept free of obscuring vegetation if they are to help identify the location of pipelines, which is the purpose of §192.707.

Interpretation Summary	Date: 12-22-80 Question. Can a pipeline "stile" be used on one side of the road with a marker on the other side? Answer: The word "stile" is not defined or used in 49 CFR Part 192. The dictionary definitions of "stile," - "a step or set of steps for passing over a fence or wall," "a turnstile," or a "vertical member in a frame or panel into which the secondary members are fitted," - do not make it clear how a "stile" could be used to identify the location of a transmission line or main. Nevertheless, §192.707 does not limit operators to the use of any particular type of line marker. In other words, any marker will suffice provided it meets the general requirements as to placement, characteristics, and wording prescribed by §192.707.
Interpretation Summary	Date: 07-16-91 In your letter, you described " a rural farm tap serving more than one customer that is located on private property, in a cultivated field, 100 yards off an unpaved county road." You stated that the area "is normally encountered only by the landowner." You asked if a pipeline located in such an area is considered "accessible to the public" under §192.707(c). For the purpose of §192.707(c), we consider an area accessible to the public if entrance into the area is not physically controlled by the operator or if the area may be entered without difficulty. Based on these criteria and your description of the farm tap's location, we consider the farm tap to be located in an area accessible to the public for the following reasons: 1) the area is not under the operator's control, and 2) the area is not described as having any man-made or natural impediments to prevent public access. The application of the regulation depends upon all factors relevant to whether an operator exercises physical control or whether an area is difficult to enter. These factors can only be ascertained by examination of the site. Two factors to consider are whether the area is adequately fenced and locked or guarded, and if not fenced, the remoteness of a facility from areas frequented by the public. These and other relevant factors should be considered by enforcement personnel in applying section §192.707(c) to given situations.

Interpretation Summary	Date: 02-04-92 Part 192 does not define "heavily developed urban areas." as referenced in §192.707(d)(1). All Class 4 locations - places where building four or more stories in height are prevalent - are included in the term "heavily developed urban areas." Buildings of four or more stories normally are prevalent only in such areas. The definition of "Class 3 location" does not necessarily indicate that the location is in a heavily developed urban area. Yet the definition could encompass such areas, depending on the circumstances. We consider the surroundings of a Class 3 location to decide if all or part of it is a heavily developed urban area for purposes of §192.707(d) (1).
GPTC	Industry guidance available.
Other Ref. Material & Source	None
New Guidance Material	- Install line markers for each transmission line that crosses or lies in close proximity to any high risk area where, in the operator's judgment, the potential for future excavation or damage is likely such as: . Flood zone areas. . Irrigation ditches and canals subject to periodic excavations for cleaning out or deepening. . Drainage ditches subject to periodic grading, including those along roads. . Agricultural fields subject to deep plowing or where deep-pan breakers are employed. . Active drilling or mining areas. . Waterways or bodies of water, especially those subject to dredging or commercial vessel activities. . Fence lines, notable changes in direction, or exposed pipe including spans. - Temporary or permanent line markers are required when the pipeline becomes exposed by design or through acts of nature (erosion by wind or water), in areas accessible to the public. - Projects of long duration near or on the pipeline may require more frequent verification that markers are in place (see damage prevention guidance). - Line of sight (can physically see from one marker to the next marker) is not required in areas where the land use does not reasonably permit such installation (i.e. corn field, swamp, forests and other such examples). - Multiple lines in a common ROW must have individual markers. - Assure line markers have current operator name. - Verify that listed 24-hour phone number is routed to actual person, not just a recorder. - Other methods of indicating the presence of the line are adequate (such as stenciled

	markings, cast monument plaques, signs or other devices installed in curbs, sidewalks, streets, building facades or any other appropriate location) where the use of conventional markers are not feasible. - Consider where feasible to include on the line marker the Dig Safely national campaign logo and message: Call Before You Dig; Wait the Required Time for Marking; Respect the Marks; and Dig With Care. Call your local One-Call Center or the toll-free National Referral number, 1-888-258-0808. - All exposed pipe must have a marker, whether the pipe is intentionally or unintentionally exposed. - A secured, fenced, aboveground pipeline facility does not require line marker if signs with sufficient information are provided. - Stickers, as long as permanently affixed and fully legible must be applied may be applied over outdated info as soon as practicable (within six months) over outdated information: however, the telephone number must reach the pipeline operator at all times.
Examples of a Violation	- Buried main or transmission line is not marked at the crossing of a public road, railroad and it is practicable to do so, and no interference prevention program is established by law. - There are an inadequate number of line markers, operator name & phone number, and no markers at aboveground pipelines accessible to the public. - There is no marker in other areas where a marker would be necessary to reduce the possibility of damage or interference. - Above-ground main or transmission line in area accessible to public is not marked. - Markers have not been updated or do not contain required information. - Exposed pipe including wash-outs and spans, in areas accessible to the public, without markers.
Evidence Guidance	- Documentation showing that a pipeline is a jurisdictional transmission line or jurisdictional gathering line, including operator's records, FPC/FERC certification, photograph, description by investigator, etc. - Documentation showing the class location for the transmission line, including operator's records, photograph, description by investigator, etc. - Documentation showing whether the pipeline is at highway or railroad crossing, including operator's records (maps), photographs, description by investigator, etc. - Documentation showing that an above ground pipeline is not marked in an area accessible to the public, including operator's records, photograph, description by investigator, etc. - Documentation that it is not impractical to locate the marker, including investigator's analysis of practicability. - Verification that no interference prevention program has been established by law, including statements of knowledgeable State and local government officials. - Documentation that marker does not meet requirement of §192.707(d), including color photographs and detailed investigator description of measurements and other characteristics.

Other Special Notations	None noted

Existing Code Language:	Each operator shall maintain the following records for transmission lines for the periods specified: (a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service. (b) The date, location, and description of each repair made to parts of the pipeline system other than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section. (c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-78, 06-06-96
Interpretation Summary	None provided
GPTC	None provided
Other Ref. Material & Source	None noted
New Guidance Material	- Computerized records are acceptable, if sufficient details are included. - Patrolling and equipment malfunction reports should generate follow-up maintenance activities and their associated records.
Examples of a Violation	- Operator did not maintain records for the required time periods. - Computerized records were not managed properly, lost, deleted or otherwise destroyed. - Omission of required records.
Evidence Guidance	- Documentation that no record of the event was kept, including operator's or investigator's statement of absence of record. - Operator representative=s statement regarding the missing records.
Other Special Notations	None noted

§192.711	**Transmission Lines: General Requirements for Repair Procedures**

Existing Code Language:	(a) Each operator shall take immediate temporary measures to protect the public whenever: (1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and (2) It is not feasible to make a permanent repair at the time of discovery. As soon as feasible the operator shall make permanent repairs. (b) Except as provided in ' 192.717(b)(3), no operator may use a welded patch as a means of repair.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-88, 12-14-99
GPTC	Industry guidance available.
Other Ref. Material & Source	Pipeline Repair Manual, PRCI, Rev. 1.0, December, 1999. (This is in the Inspector's Toolbox).
New Guidance Material	- If it is not feasible to make an immediate permanent repair at the time of discovery, then measures to ensure public safety must be taken by the operator; such as a temporary repair, lowering the operating pressure, or other measures. - A temporary repair does not have to be replaced with a permanent repair within a specified time period, unless the operator=s procedures give specific guidance. - Patches are not permitted on pipe whose MAOP would produce an effective hoop stress at or above 40% of SMYS (ref. §192.717(b)(3)). - Associated permanent repair requirements are also addressed in §192.713, §192.715, and §192.717.
Examples of a Violation	- Operator discovered a leak, imperfection, or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40% of the SMYS, but failed to make a permanent repair as soon as feasible. - Operator discovered a leak, imperfection, or damage that impairs the serviceability of a segment of steel transmission line operating at or above 40 percent of the SMYS, but failed to take immediate temporary measures to protect the public when a permanent repair was not immediately feasible - Operator used a patch that does not comply with §192.717(b)(3).
Evidence Guidance	- Operator=s procedures. - Documented statements from operator. - Operator=s Afirst discovery@ records/reports. - Operator=s maintenance records/reports. - Documentation of the pipeline segment=s SMYS. - Photographs.

Other Special Notations	None noted

Existing Code Language:	(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be- (1) Removed by cutting out and replacing a cylindrical piece of pipe; or (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. (b) Operating pressure must be at a safe level during repair operations.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-88, 12-14-99
Interpretation Summary	None provided
GPTC	Industry guidance available.
Other Ref. Material & Source	Pipeline Repair Manual, PRCI, Rev. 1.0, December, 1999. (This is part of the Inspector's Toolbox).
Other Ref. Material & Source	API 1104, Appendix B, 19th Edition. Welding Standard
New Guidance Material	- Guidelines for timeframes for repairs in "covered segments" can be found in the Gas Integrity Management rule, 192 Subpart O. - The repair method selected must be able to "permanently restore the serviceability of the pipe," with a result comparable to that expected from replacing damaged pipe or installing a full-encirclement split sleeve. - Such restoration is considered permanent if the repair is expected to last as long as the pipe under normal operating and maintenance conditions. - The repair method meets the performance standard and the method must have undergone "reliable engineering tests and analyses." - The tests and analyses need only be what a reasonable and prudent professional engineer would consider adequate to demonstrate compliance with the performance standard. - These repair methods do not require the pipe to be replaced even if it is feasible to take a damaged pipeline out of service. - Alternatives to composite pipe wrap type repair should be considered on above-grade piping where there is a possibility of fire hazards. - Appropriate NDT assessment should be performed in conjunction with repairs (§192.241, §192.719). - UT examination of the repair area should be performed immediately prior to the intended repair work to assure safe working conditions. - Direct deposit welding requires a specific qualified welding procedure and welder qualification.

	- If the pipeline is to be repaired without taking it out of service, the operating pressure must be monitored during the repair process to insure a safe pressure, which may or may not require a pressure reduction.
Examples of a Violation	- Operator failed to establish procedures as outlined in §192.713. - Operator failed to properly remove/repair an imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40% of SMYS. - Operator repaired a line, but failed to reduce the operating pressure to a safe level during repairs. - Making a direct deposit weld repair without a specific procedure or engineering analysis. - No engineering test and analysis completed to support the direct deposit welding procedure being utilized.
Evidence Guidance	- Operator=s procedures. - Documented operator=s statements. - Operator=s maintenance records/reports. - Engineering assessments and analysis.
Other Special Notations	None noted

Existing Code Language:	Each weld that is unacceptable under '192.241(c) must be repaired as follows: (a) If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements of '192.245. (b) A weld may be repaired in accordance with '192.245 while the segment of transmission line is in service if: (1) The weld is not leaking (2) The pressure in the segment is reduced so that it does not produce a stress that is more than 20 percent of the SMYS of the pipe; and (3) Grinding of the defective area can be limited so that at least 1/8-inch (3.2 millimeters) thickness in the pipe weld remains (c) A defective weld which cannot be repaired in accordance with paragraph (a) or (b) of this section must be repaired by installing a full encirclement welded split sleeve of appropriate design
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-85, 07-13-98
Interpretation Summary	None provided.
GPTC	Industry guidance available.
Other Ref. Material & Source	- API 1104, 19th Edition, Welding Standard. - Pipeline Repair Manual, PRCI, Rev. 1.0, December, 1999 (This is part of the Inspector's Toolbox). - Alert Notice ALN 87-0, Incident involving the fillet welding of a full encirclement repair sleeve on a 14" API 5LX-52 pipeline.
New Guidance Material	- Some weld defects during initial construction as listed in API-1104, Section 6 , can be repaired once in the same physical location on the weld, using the same welding procedure as was used to make the original weld. - A weld area can be repaired only one time with the original welding procedure. Multiple repairs are permissible as long as they are not in the same location on the weld. - A weld that has already been repaired at a specific location can be repaired again at that location with a separate qualified welding repair procedure. The repaired area is only a small portion of the total weld. Therefore, the qualification of this procedure is treated as a fillet weld, and only four straps are required from the repaired area to test and qualify the repair procedure. - Other code requirements are addressed in §192.245. - Direct deposit welding requires a specific welding procedure and welder qualification.

Examples of a Violation	- Making more than one repair to a weld in the same area without a specific welding repair procedure. - A repaired weld did not meet the requirements of API-1104, Section 6.
Evidence Guidance	- Photographs of repaired weld, if still exposed. - Records associated with the repairs. - Copies of NDT evaluations. - Copies of the welding procedure. - Qualification records used to establish the welding procedure.
Other Special Notations	None noted

Existing Code Language:	Each permanent field repair of a leak on a transmission line must be made by- (a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or (b) Repairing the leak by one of the following methods: (1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS. (2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp. (3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size. (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design. (5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.
Origin of Code	Original Code Document, 08-17-70
Last FR Amendment	192-88, 12-14-99
Interpretation Summary	None provided
GPTC	Industry guidance available.
Other Ref. Material & Source	Alert Notice ALN 87-01 Incident involving the fillet welding of a full encirclement repair sleeve on a 14" API 5LX-52 pipeline.
Other Ref. Material & Source	Pipeline Repair Manual, PRCI, Rev. 1.0, December, 1999 (This is part of the Inspector's Toolbox).
New Guidance Material	- If the pipeline is to be repaired without taking it out of service, the operating pressure must be reduced to a safe level during the repair process. - Determination of the safe operating pressure during the repair is left up to the operator, through their application of pre-established guidance material. - Appropriate UT examination of the repair area should be performed to insure the integrity of the planned repair. - Appropriate NDT (see §192.241) methods must be used after the repair to evaluate the integrity of the weld repair.

Examples of a Violation	- An incident occurs while repairs are being attempted. - The MAOP of the replacement cylinder is not commensurate with §192.619. - Patch installed on the pipe that has a yield of 40,000psi or more (§192.717(b)(3)).
Evidence Guidance	- Photographs of the pipe prior to the repair. - Photographs of the repair. - Copies of documents that describe the repairs made to the pipeline. - Documentation of the pipe specifications.
Other Special Notations	None noted

Existing Code Language:	a) Testing of replacement pipe. If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed. (b) Testing of repairs made by welding. Each repair made by welding in accordance with ''192.713, 192.715, and 192.717 must be examined in accordance with '192.241.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-54, 11-18-86
Interpretation Summary	Date: 06-07-94 Question : "Our second question relates to the hydrostatic testing of replacement pipe under § 192.719(a). In a repair situation where several joints of pipe are welded together, does the welded piece have to be hydrostatically tested as a unit? Each joint is pre-tested and the welds are 100% non-destructively tested." Answer: Section 192.719(a) is intended for testing of repairs of transmission pipelines, where the pipe is required to be tested as a new line. The test requirements in Subpart J are applicable to a new segment of pipeline, or the return to service of a segment of pipeline that has been relocated or replaced. In accordance with § 192.503(a) in Subpart J, the entire replaced segment must be tested in accordance with Subpart J and § 192.619, except the tie-in joints that are excepted under § 192.503(d). It should be noted that the joints connecting the several pipe lengths are not tie-in joints. However, if, in accordance with § 192.505(e), it is not practical to conduct a post installation test, a preinstallation strength test must be conducted on each pipe length or the segment by maintaining the pressure at or above the test pressure for at least 4 hours.
GPTC	Industry guidance available
Other Ref. Material & Source	None provided.

New Guidance Material	- Appropriate UT examination of the repair area should be performed to insure the integrity of the planned repair. - A pipe segment that is replaced must be pressure tested after installation unless it is not practical, in which case each length of pipe or each segment must be pressure tested. - Special attention should be applied to the potential for stresses associated with out-of-roundness, high-low, alignment, and changes in pipe wall or grade. - Records documenting pretest of pipe for emergency use must include an audit trail to each specific joint of pipe installed in the pipeline.
Examples of a Violation	- Test records for installed pipe cannot be traced back to the original test documentation. - NDT records are not available concerning inspection of welds made on repair fittings and devices.
Evidence Guidance	- Records regarding the repairs made to the pipeline. - Statements from supervisory personnel regarding any missing or incomplete records. - Metallurgical reports. - Accident reports.
Other Special Notations	None noted

Existing Code Language:	(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section. (b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard. (c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard. (d) Whenever service to a customer is discontinued, one of the following must be complied with: (1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. (2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly. (3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed. (e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging. (f) Each abandoned vault must be filled with a suitable compacted material. (g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. (1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at www.npms.rspa.dot.gov or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@rspa.dot.gov. The information in the report must contain all

	reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws. (2) Data on pipeline facilities abandoned before October 10, 2000 must be filed by before April 10, 2000. Operators may submit reports by mail, fax or e-mail to the Information Officer, Research and Special Programs Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@rspa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-89, 08-28-00
Interpretation Summary	None provided.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted
New Guidance Material	- An abandoned pipeline must be physically isolated (does not require an air gap) from active pipelines and disconnected from all sources of gas. (§192.3). - An inactive (idle) pipeline is a pipeline that is being maintained under Part 192 but is not presently being used to transport gas; that may or may not contain pressurized gas. - Deactivation (inactivation) is the process of making the pipeline inactive.
Examples of a Violation	- An offshore pipeline was abandoned in place and was not disconnected from all sources and supplies of gas; purged of gas; filled with water or inert materials, or sealed at the ends. - A customer has been inactive for an extended period of time, and its connection has not either been locked, blinded or otherwise separated (§192.727(d)). - The operator did not file a report to OPS-NPMS for each abandoned offshore facility, as required by §192.727(g). - The operator did not file a report to OPS-NPMS for each on shore over, under or through a commercially navigable waterway, as required by §192.727(g).

Evidence Guidance	- Documentation/Photos/Statements that show the operator did not disconnect the abandoned pipeline from all sources and supplies of gas, and purged of gas. - Operator did not fill an abandoned offshore pipeline with water or inert materials; and sealed at the ends. - If air is used for purging, documentation showing that operator did not insure that a combustible mixture was not present after purging. - Documentation/Photos/Statements that shows an abandoned vault was not filled with a suitable compacted material.
Other Special Notations	None noted

Existing Code Language:	(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §192.739 and §192.743, and must be operated periodically to determine that it opens at the correct set pressure. (b) Any defective or inadequate equipment found must be promptly repaired or replaced. (c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-43, 10-21-82
Interpretation Summary	Date: 01-28-77 The word "pressure" in §§192.731, 192.739, and 192.743 restricts the applicability of those sections to devices or stations which serve to relieve or limit gas pressure. <u>The sections do not apply to devices or regulators which are part of non-gas carrying equipment inside gas compressor stations.</u> This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of Section 192.192 for installation of pressure control devices. Since under §192.3 the term "pipeline" encompasses all the gas carrying parts of an operator's systems, the pressure relief devices and limiting stations subject to §§192.731, 192.739, and 192.743 are those on a pipeline.
Interpretation Summary	Date: 06-01-79 I am responding to your letter dated March 12, 1979, to Mr. George Orr, Office of Operations and Enforcement (Pipeline Safety) Houston, Texas, in which you question the applicability of §§192.731, 192.739, and 192.743 to relief devices or regulators installed on piping systems or storage vessels not containing gas. The word "pressure" in §§192.731, 192.739, and 192.743 restricts the applicability of those sections to devices or stations which serve to relieve or limit gas pressure. <u>The sections do not apply to devices or regulators which are part of non-gas carrying equipment that may exist inside gas compressor stations.</u> This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of Section 192.195 for installation of pressure control devices. Since under §192.3 the term "pipeline" encompasses all the gas carrying parts of an operator's systems, the pressure relief devices and limiting stations subject to §§192.731, 192.739, and 192.743 are those on a "pipeline."

Interpretation Summary	Date: 02-08-99 This responds to your request for an official interpretation of §§192.731, 192.739 and 192.743. You asked if these sections apply to compressor station relief devices that relieve natural gas in equipment and systems associated with operation of the compressor, such as fuel gas lines and instrument gas lines. *Does the interpretation mean any vessel or piping in the compressor station that contains natural gas for whatever purpose is jurisdictional?* Answer: At a minimum, the interpretation applies to gas relief devices on any vessel or piping in the compressor station that is used in the transportation of gas. It is unclear whether §192.731 was intended to cover devices on vessels or piping that are unrelated to gas transportation by pipeline. *Does the gas in the aforementioned vessels or piping have to be in transportation, i.e. passing through the vessel or piping on route to the consumer before the vessel or piping is considered jurisdictional?* Answer: Subpart M, and consequently §192.731, applies to the maintenance of pipeline facilities, i.e. things used in gas transportation by pipeline. It doesn't matter whether the vessel or piping actually carries gas in transportation. Although there may be a question whether a fuel gas line carries gas in transportation, it's certainly used in transportation and, therefore, a pipeline facility. *Would blanket gas injected over the top of a liquid such as glycol in a tank (with a relief device) make the tank and related devices subject to the regulations?* Answer: Yes, if the tank is used in gas transportation by pipeline.
GPTC	Industry guidance available .
Other Ref. Material & Source	None noted
New Guidance Material	-Testing and inspection of all devices is required to be performed at least once each calendar year, not to exceed 15 months, as per §192.739(a). - Determination of set pressure should be derived from both MAOP and SMYS considerations, see §§192.739 and 192.743 for guidance. - Testing methods should not create the potential for an over-pressure condition. - Set pressures for primary pressure regulating or control devices must be set so as to prevent the system from being normally operated above the MAOP. - If there is no automatic pressure regulating or control device that prevents a pipeline from being normally operated above the MAOP then pressure relief devices associated with that system should not be set above the MAOP of the pipeline being protected. - Factors affecting the calculation of capacity can be derived from manufacturer data and/or direct measurement during full flow conditions.

	- Calculated capacity must include the effect of piping size and length associated with the relief device. - The device capacity should be based on the largest single upstream pressure regulating or pressure control device failure that may occur. - If calculations or determination otherwise indicates that capacity is not adequate, adjustments should be made promptly. - Relief valve outlet piping and vent stack should be included in capacity calculations. - During annual testing, at least one remote control shutdown device must be used to activate the facility=s shutdown utilities; however, actual gas blow-down is not required. - All individual remote control shutdown devices must be tested to verify that they each can activate the facility=s shutdown utilities. - Connectivity and calibration between unit trip sensors and its associated unit control panel should be verified during testing. - Unit trips within the station may be the primary means of over-pressure protection; and may work with redundant or secondary reliefs to achieve or enhance station blow-down. - If check valves are used to provide station isolation during blow-down, the operator must verify the integrity of the seal on the check valves. - Conventional and check valves used as a part of the remote control shutdown (ESD) system must be inspected and tested to verify adequate seals for pressure isolation on an annual basis (§192.731(c)). - Set points and capacities of back-up or secondary over-pressure safety devices do not have to meet the code requirements, but the devices must be tested for functionality once each calendar year, not to exceed 15 months. - If a station built before March 21, 1971 has no over-pressure protection devices and it is significantly altered; then over-pressure protection devices must be added. - All equipment found to be defective or inadequate during these inspections and tests must be promptly repaired or replaced. - Regulators and overpressure protection devices on compressor fuel gas or instrumentation gas lines are subject to the requirements of §§192.731, 192.739, and 192.743.
Examples of a Violation	- A remote control shutdown device is not inspected and tested within the required intervals. - The review of the required capacity, the inspection, or the testing of the relief device is not made within the required intervals. - Actual relief or unit trip pressures do not match required settings. - Capacity calculations do not match the current station piping design. - Changes to the station required that relief capacity needed to be greater, but no changes were incorporated in a timely manner. - Equipment inspection reports indicate that a valve used for isolation (ESD) and blowdown was noted as in need of maintenance that was not repaired promptly. - Inspection reports for pressure control/pressure relief devices indicate that repairs

	were required but those repairs have not been made promptly. - Regulators and over pressure protection devices on compressor fuel gas and instrumentation gas have not been tested and inspected at the required intervals. - A pressure limiting device that has a set point set above the limits allowed under §192.739. - A pressure limiting device that fails to operate at the set point which then leads to an incident.
Evidence Guidance	- Operator=s listing of station ESD valves and controlling devices. - Pressure control/pressure relief inspection and test records. - Photographs. - Documentation of increased compressor flow rates. - Capacity calculation sheets. - MAOP listings. - Pressure charts or pressure database records. - Station shutdown reports. - Trip device inspection records. - Station schematics.
Other Special Notations	None noted

§192.736	Compressor Stations: Gas Detection

Existing Code Language:	(a) Not later than September 16, 1996, 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 (746 kilowatts) or less. (b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must- (1) Continuously monitor the compressor building for a concentration 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.
Origin of Code	192-58, 09-16-93
Last FR Amendment	192-85, 07-13-98
Interpretation Summary	None provided
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted
New Guidance Material	- This requirement became effective on 09-16-96, and is retroactive to all affected stations. - Since this requirement is now greater than five years old, the operator should not be required to demonstrate that the installed system was in place by the effective date. - Since the noise level in active stations may be high, a visual indication (i.e. strobe) will probably be necessary to adequately alert those within the building. - A horn, and perhaps a beacon, should be applied outside of the building - Since gas detectors are normally mounted high in the building, special testing techniques may need to be applied to ensure the system will activate at 25% LEL. - Operators should be using manufacturer guidance or operator=s experience for periodic testing and maintenance intervals. - The operator is allowed to set the inspection interval and must provide justification for why the inspection cycle is longer than one year intervals. - The operator should maintain records to demonstrate satisfactory testing in a reasonable interval.

	- The gas detection alarm signal should be unique from other facility alarms. - Station shutdown or blow-down is not required on the occurrence of a 25% LEL gas detection alarm; however, their procedures must address, investigate, and/or eliminate the hazard. - Gas detectors should be mounted in places where gas is likely to accumulate inside the building. - Having an alarm only in the control room is insufficient.
Examples of a Violation	- Gas detection threshold is greater than 25% LEL. - There is a horn but no visual indicator in the building and the horn is not loud enough to overcome engine noise. - There is no horn or strobe/beacon outside the building. - Mounting location, visibility or volume of equipment is not sufficient. - Gas detectors not mounted in places where gas may accumulate inside the building.
Evidence Guidance	- Inspection and test records, including threshold settings. - Photographs showing the location of detector installation. - The brightness of the strobe, or volume of audible alarms is insufficient; in light of their placement or competition with other distractions. - Accident reports. - Documented statements from the operator.
Other Special Notations	None noted

Existing Code Language:	(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 it is- (a)(1) In good mechanical condition; (a)(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed; (a)(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressures consistent with the pressure limits of '192.201(a); and (a)(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation. (b) For steel pipelines whose MAOP is determined under '192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-96, 05-17-04 Effective Date: 09-14-04
Interpretation Summary	Date: 06-01-79 The word "pressure" in §§192.731, 192.739, and 192.743 restricts the applicability of those sections to devices or stations which serve to relieve or limit gas pressure. The sections do not apply to devices or regulators which are part of non-gas carrying equipment that may exist inside gas compressor stations. This interpretation is based on the relationship between the words "pressure" and "gas" occurring throughout Part 192 and in particular in the requirements of §192.195 for installation of pressure control devices.

If the MAOP produces a hoop stress that is:	Then the pressure limit is:
Greater than 72 percent of SMYS.	MAOP plus 4 percent.
Unknown as a percentage of SMYS.	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

Interpretation Summary	Date: 06-28-88 Any regulator serving a downstream main is a pressure regulating station. While the drafters of the industry definition may not have had in mind regulators that serve mains in master meter systems, such regulators do meet the terms of the definition. Also, they function similarly to other regulators that are generally recognized to come under the definition.
Interpretation Summary	Date: 07-23-92 If an operator seeks to satisfy the requirements of over-pressure protection by relying on over-pressure devices of others, the operator is still responsible for compliance with §192.743. If an operator maintains a pressure limiting or regulating station that was built before March 12, 1971 that was not designed with over-pressure protection devices, and has not been changed or modified since that time, then the operator is not required to install over-pressure protection at that station, unless §192.619(a)(4) applies.
Interpretation Summary	Date: 04-28-93 Set-point, lock-up, and full-stroke-operation would be part of the inspection and testing if such tests are practicable at the station concerned...... Consequently, all the inspections and tests that can be done at some regulator stations may not be practicable at stations with service-type regulators.......Practicable inspections and tests do not require the operator to disassemble the regulator, re-pipe the regulator, or cut off the supply of gas to the system. Instead, we suggest that, as a minimum, these service-type regulators be visually inspected, be checked for leaks (including the regulator vent), and be checked for correct set-point.
Interpretation Summary	Date: 02-08-99 This responds to your request for an official interpretation of §§192.731, 192.739 and 192.743. You asked if these sections apply to compressor station relief devices that relieve natural gas in equipment and systems associated with operation of the compressor, such as fuel gas lines and instrument gas lines. *Does the interpretation mean any vessel or piping in the compressor station that contains natural gas for whatever purpose is jurisdictional?* Answer: <u>At a minimum, the interpretation applies to gas relief devices on any vessel or piping in the compressor station that is used in the transportation of gas.</u> It is unclear whether §192.731 was intended to cover devices on vessels or piping that are unrelated to gas transportation by pipeline. *Does the gas in the aforementioned vessels or piping have to be in transportation, i.e. passing through the vessel or piping on route to the consumer before the vessel*

	or piping is considered jurisdictional? Answer: Subpart M, and consequently §192.731, applies to the maintenance of pipeline facilities, i.e. things used in gas transportation by pipeline. It doesn't matter whether the vessel or piping actually carries gas in transportation. Although there may be a question whether a fuel gas line carries gas in transportation, it's certainly used in transportation and, therefore, a pipeline facility. *Would blanket gas injected over the top of a liquid such as glycol in a tank (with a relief device) make the tank and related devices subject to the regulations?* Answer: Yes, if the tank is used in gas transportation by pipeline.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted
New Guidance Material	- Also see §192.743 guidance for capacity guidance. - Set pressures for pressure protection/relief devices must be set so as to prevent system pressures from exceeding the pressure limits of either §192.201(a) or §192.739(b), which ever is applicable. See below.

If the MAOP:	Then the pressure limit is:
Produces a hoop stress equal to or less than 72% of SMYS and is 60 psig or greater.	The lower of… MAOP plus 10 percent or 75% SMYS.
Produces a hoop stress equal to or less than 72% of SMYS and is 12 psig or more, but less than 60 psig.	MAOP plus 6 psig.
Produces a hoop stress equal to or less than 72% of SMYS and is less than 12 psig.	MAOP plus 50 percent.
Was determined under §192.619(c) and produces a hoop stress greater than 72% of SMYS .	MAOP plus 4 percent.
Was determined under §192.619(c) and produces a hoop stress that is unknown as a percentage of SMYS.	A pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.

- Visually check station piping supports, control/sensing/supply lines, and ventilating equipment for proper design and maintenance.
- If a pipeline was either built or significantly modified after March 12, 1971 and the pressure limiting device is removed from service for testing; adequate over-pressure protection of the affected line must still be maintained.
- Device testing records **should** include the set pressure of the device as well as the name of the individual who did the testing.

	- Testing relief valves to determine they are in good mechanical condition requires, in part, physical movement of the valve plug to assure the valve can open. - Relief stacks must be free of obstructions and have rain caps or weep holes. - If operational checks, as well as the required testing and inspection, indicate malfunctions that make a pipeline segment unsafe, the device must be replaced, repaired, or removed from service within a reasonable time frame, see §192.703(b). - If a check valve is used as a primary pressure control device to protect a pipeline from a higher pressure source, then that check valve must be tested and inspected once each calendar year not to exceed 15 months for flow-by leakage that could cause pressures to exceed the MAOP. - The occurrence of over-pressure may be indicative of an equipment failure or design flaw. - Facilities not in service, but still physically connected, must meet the inspection and testing requirements of §192.739. - Regulators and over pressure protection devices on compressor fuel gas lines and instrumentation gas are subject to the requirements of 192.731, 192.739, and 192.743. Facility Design Considerations - For a pipeline or pipeline facility that was either built or significantly modified after March 12, 1971 the downstream pressure rating of a regulator must be capable of withstanding pressures it would be subjected to if it were to fail open. §192.143. - If a facility has been installed or modified after March 12, 1971, and there is only a single pressure control device, the operator must also be able to show that the failure of that device will not cause the MAOP to be exceeded, otherwise there must be an over-pressure protection device installed that will meet the requirements of §192.199 and §192.201. A check valve that isolates a pipeline segment from a higher pressure facility (gas source), could be considered a pressure control device. §192.195. - If the regulator assembly includes a worker/monitor configuration, then separate taps and sensing lines are required; or be designed to fail-safe. §192.199. - Facilities either built or significantly modified after March 12, 1971 are required to meet the requirements of 192.201(a): Setpoints can either be locally or remotely controlled or set; however, sole reliance on remote human intervention to activate a safety valve in the case of regulator or pressure control failure does not satisfy the set point requirements of 192.201(a). - In citing a violation of inadequate or non-existent overpressure protection equipment (192.195(a)) it is incumbent upon the inspector to obtain adequate information from the operator to demonstrate that MAOP could be exceeded as a result of pressure control or other type of failure. This may involve flow and pressure gradient studies, simulations, etc.
Examples of a	- Excessive ice buildup on the downstream side of a regulating station that impedes

Violation	the operation of the any pressure protection device. - Test or review of the required capacity of the relief device is not made within the required intervals. - Inspection and testing of an overpressure protection device has not been completed within the required intervals. - Actual relief set pressures do not match required settings. - Capacity calculations do not match the current station piping design. Capacity calculations should include downstream piping capacity calculations for maximum pressure and flow, so as not to choke the relief valve. - Changes to the station required that relief capacity needed to be greater, but no changes were incorporated in a timely manner. - Repairs to pressure control/pressure relief devices to correct an unsafe condition have not been made within a reasonable amount of time. Go to 192.703. - Regulators and over pressure protection devices on compressor fuel gas and instrumentation gas have not been tested and inspected at the required intervals. - A pressure limiting device that has a set point set above the pressure limits allowed. - A pressure limiting device that fails to operate at the set point due to lack of maintenance. - Corrosion, mechanical damage or a precarious arrangement of the device or associated control piping. - Capacity calculations that pre-date piping changes (or other factors) that may have impacted actual capacity requirements. - Unprotected relief ports that would be subject to damage or restriction from water, ice, debris, etc. - A facility built or significantly modified after March 12, 1971 has out of service tests conducted without an equivalent temporary device or adequate manual control to protect against the possibility of over-pressure.
Evidence Guidance	- Test records. - Photographs. - Station schematics. - Documentation of increased upstream regulator capacity. - Capacity calculation sheets. - MAOP listings. - Maintenance records. - Stations pressure charts or database pressure history. - Accident reports.
Other Special Notations	None noted

Existing Code Language:	(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in '192.739(b), the capacity must be consistent with the pressure limits of '192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations. (b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient. (c) If the relieving device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-96, 05-17-04 Effective date: 09-14-04
Interpretation Summary	Date: 06-01-79 The sections do not apply to devices or regulators which are part of non-gas carrying equipment that may exist inside gas compressor stations.
Interpretation Summary	Date: 07-23-92 If an operator seeks to satisfy the requirements of over-pressure protection by relying on over-pressure devices of others, the operator is still responsible for compliance with §192.743. If an operator maintains a pressure limiting or regulating station that was built before March 12, 1971 that was not designed with over-pressure protection devices, and has not been changed or modified since that time, then the operator is not required to install over-pressure protection at that station, unless §192.619(b) applies.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted

§192.743	Pressure Limiting and Regulating Stations: Capacity of Relief Valves

New Guidance Material	- Also see guidance for §192.739. - Several factors that may suggest that testing be performed out-of-service are continuity of service and the potential for creating a hazardous condition caused by venting gas. - Venting gas should not create the potential for a hazardous condition (i.e. static discharge from overhead electrical lines, accumulation of gas in a building) (see §192.201). - When conducting tests in-place, continuity of service may be a important factor. - Successful testing should not create an over-pressure condition. - If pressure other than MAOP is used for capacity calculation of over-pressure protective devices, there must be specific procedures in place to address the effect of changes in operating pressure on the effective relief capacity. - Set points and capacities of back-up or secondary over-pressure safety devices do not have to meet the code requirements, but the devices must be tested for functionality on an annual basis, not to exceed 15 months. - Regulators and over pressure protection devices on compressor fuel gas lines are subject to the requirements of §§192.731, 192.739, and 192.743. - Factors affecting the calculation of capacity can be derived from manufacturer data, direct measurement during full flow conditions and/or industry models. - Relief valve piping (inlet and outlet) and vent stack should be addressed in capacity calculations. - Operators may use minimum demand loads in the capacity calculations, but must be able to substantiate and prove by historical documentation or engineering calculations those minimum demand calculations. - Capacity checks can be determined from historical engineering calculations, as long no changes have been made to the facilities, related MAOP=s or operating parameters. - The device capacity should be based on the largest single upstream pressure control failure that may occur - If calculations or determination otherwise indicates that capacity is not adequate, adjustments must be made promptly (see §192.703(b). - If a station built before March 21, 1971, that has no over-pressure protection devices, is significantly altered; then over-pressure protection devices must be added.
Examples of a Violation	- Test or review of the required capacity of the relief device is not made within required intervals. - Capacity calculations pre-date piping changes (or other factors) that may have impacted actual capacity requirements. - Out of service tests, conducted without an equivalent temporary device or adequate manual control to protect against the possibility of over-pressure.

Evidence Guidance	- Test records. - Photographs. - Capacity calculation sheets. - MAOP listings. - Pressure charts or pressure database records.
Other Special Notations	None noted

Existing Code Language:	(a) Each transmission line valve that might be required during any emergency 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, unless the operator designates an alternative valve.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-93, 09-15-03 Effective date: 10-15-03
Interpretation Summary	None noted
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted
New Guidance Material	- The operator should identify the valves on the pipeline system that might need to be opened/closed during an emergency situation. - The operator should establish, and periodically review, a master list of emergency valves. - ESD valves are emergency valves, although they may be shown on a separate list. - The emergency valve list and the process to identify related valves should be reviewed for §192.745 requirements. - Operator must inspect and partially operate all emergency valves within the required time intervals of §192.745. - Operator should use specific valve manufacturer's recommendations to develop an appropriate maintenance program. - Maintenance discrepancies identified during valve inspections must be addressed and remedial actions documented.
Examples of a Violation	- Certain valves were not included in emergency valve list. - Operator did not inspect or partially operate some or all of the valves addressed in §192.745. - The operator=s inspection interval for some or all valves was longer than required in §192.745.

Evidence Guidance	- Emergency valve list. - Pipeline schematics. - Station drawings. - ESD records. - Operator=s O&M procedures. - Documented statements from the Operator. - Operator=s maintenance records. - Photographs.
Other Special Notations	None noted

Existing Code Language:	(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 leaks found must be repaired. (c) The ventilating equipment must also be inspected to determine that it is functioning properly. (d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	192-85, 07-13-98
Interpretation Summary	None noted.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted.
New Guidance Material	None provided.
Examples of a Violation	- Inspection of the vault is not made in the required intervals. - The operator did not repair leaks that were found. - The vault ventilation equipment is not functioning properly.
Evidence Guidance	None provided.
Other Special Notations	None noted

Existing Code Language:	Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following: (a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided (b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work (c) Post warning signs, where appropriate
Origin of Code	Original Code Document, 08-19-70
Last FR Amendment	None
Interpretation Summary	Date: 07-19-90 (Preemption of Certain OSHA Excavation Standards) - Section 4(b)(1) of the Occupational Safety and Health Act (OSH Act) provides that OSHA does not apply to working conditions with respect to which other Federal agencies "exercise statutory authority to prescribe or enforce standards or regulations affecting occupational safety or health." - §192.751 addresses the same safety problem, requiring pipeline operators to "minimize the danger at accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion." This OPS regulation therefore preempts enforcement of subsection §192.651(g)(1)(iii) against employers who are subject to the DOT standard.
Interpretation Summary	Date: 06-01-94 (Preemption of Certain OSHA Confined Space Standards - Specifically Vaults) The OSHA confined space standard (29 CFR 1910.146) applies only to those operations where DOT/OPS regulations do not address working conditions.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted

§192.751	Prevention of Accidental Ignition

New Guidance Material	- Applicable procedures should be reviewed during an inspection. - The operator must follow these procedures. - Typically, these procedures prohibit, restrict, and/or control the following activities where the presence of gas might constitute a fire or explosion hazard: . smoking/open flames . operating internal combustion engines . activities that could generate static electricity or electrical arcing . welding, cutting, and other hot work . using certain non-approved electric equipment (flashlights, power tools/equipment, etc.) . working on compressor engine or appurtenances . working inside pipeline buildings (compressor and regulator buildings) . use of spark-producing hand tools; etc. . venting of gas - Operator=s performance of procedures may be observed, if feasible. - Applicable records should be reviewed to assure adequate steps were taken to prevent accidental ignition such as: . hot work/equipment permits . gas source isolation (positive shut-off) purge . lock/tag-out - Warning signs must be posted where appropriate. - With regard to the potential overlap with OSHA rules. Section 4(b)(1) of the OSH Act prohibits OSHA from exercising authority over working conditions when another agency exercises authority through regulation. - Maintenance and construction activities conducted where gas may be present should prohibit the use of tools, materials, fabrics, slings, etc. that may produce static discharge. - Operator should take precautions to minimize the potential of accumulating gas. - Spark-arresting techniques should be applied under certain hazardous conditions. - Consideration for engine exhaust stack temperatures should be included in safety plans. - Operators should maintain restricted access to hazardous areas, including safety zones for vehicular and air space domains.
Examples of a Violation	- Inadequate ignition prevention procedures. - Ignition prevention procedures were/are not followed. - Appropriate signs are not posted. - When venting gas, ignition sources are not removed from the area. - When venting gas, fire extinguishers are not present.
Evidence Guidance	- Written procedures (or lack there of). - Observed or documented violation of ignition prevention procedures. - Photographs.

Other Special Notations	None noted