January 7, 2020

Dear Guide Purchaser,


Your purchase entitles you to receive future notification of the issuance of addenda. Addenda are formatted to enable the replacement of pages in your Guide with updated pages. Addenda are available for free downloading from the GPTC webpage at www.aga.org/gptc or paper copies may be purchased at https://www.aga.org/aga-publications for a nominal fee.

On behalf of the Gas Piping Technology Committee and the American Gas Association, thank you for your purchase and interest in the Guide.

Sincerely,

[Signature]

Secretary
GPTC Z380
The changes in this addendum are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, or a block symbol (▌) where needed. There were two Federal Regulation updates for this period. Six GPTC transactions affected 9 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, adjustments to page numbering, and adjustment of text on pages. While only significant editorial updates are marked, all affected pages carry the current addendum footnote. Editorial updates as indicated “EU” affected 16 sections of the Guide (plus other sections impacted by page adjustments, etc.).

The table shows the affected sections, the pages to be removed, and their replacement pages.

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Guide for Gas Transmission, Distribution, and Gathering Piping Systems

2018 Edition

Addendum 5, December 2019

An American National Standard

Author: Gas Piping Technology Committee (GPTC) Z380
Accredited by ANSI

Approved by American National Standards Institute (ANSI)
Date: December 19, 2019

Secretariat: American Gas Association

ANSI GPTC Z380.1-2018, Addendum 5
Catalog Number: Z3801183
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Addenda to this Guide will also be issued periodically to enable users to keep the Guide up-to-date by replacing the pages that have been revised with the new pages. It is advisable, however, that pages which have been revised be retained so that the chronological development of the Federal Regulations and the Guide is maintained.

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practicable;  
   (ii) Construction of 10 or more miles of a new pipeline or replacement pipeline;  
   (iii) Construction of a new LNG plant or LNG facility; or  
   (iv) Construction of a new underground natural gas storage facility or the abandonment, drilling or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility;  
   (v) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or  
   (vi) A pipeline converted for service under § 192.14 of this chapter, or a change in commodity as reported on the annual report as required by § 191.17.  

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:  
   (i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.  
   (ii) A change in the name of the operator;  
   (iii) A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, underground natural gas facility, or LNG facility;  
   (iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter;  
   (v) The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter; or  
   (vi) The acquisition or divestiture of an existing underground natural gas storage facility subject to part 192 of this subchapter.  

(d) Reporting. An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.  


GUIDE MATERIAL

(a) Section 191.22(c)(1) requires a notice not later than 60 days before certain construction activities occur. Examples of construction activities that might trigger this advance notification to PHMSA under §191.22(c)(1) include the following.  
   (1) Right-of-way clearing, grading, or ditching performed in advance of, but associated with the construction project.  
   (2) Onsite equipment fabrication.  
   (3) Onsite installation activities.  

(b) Operators must notify PHMSA in accordance with §191.22(c)(1)(ii) for the construction of 10 or more miles of a new pipeline that did not previously exist, or replacement of 10 or more contiguous miles of line pipe in an existing pipeline (see OPS Advisory Bulletin ADB-2014-03.  

(c) Operators must notify PHMSA in accordance with §191.22(c)(1)(vi) when the commodity being transported changes from one listed below to another.  
   (1) Natural gas.  
   (2) Synthetic gas.  
   (3) Hydrogen gas.
§191.23

Reporting safety-related conditions.

[Effective Date: 07/01/2020]

(a) Except as provided in paragraph (b) of this section, each operator shall report in accordance with §191.25 the existence of any of the following safety-related conditions involving facilities in service:

(1) In the case of a pipeline (other than an LNG facility) that operates at a hoop stress of 20 percent or more of its specified minimum yield strength, general corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure, and localized corrosion pitting to a degree where leakage might result.

(2) In the case of an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well, general corrosion that has reduced the wall thickness to less than that required for the maximum well operating pressure, and localized corrosion pitting to a degree where leakage might result.

(3) Unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impair the serviceability of a pipeline or the structural integrity or reliability of an underground natural gas facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility, LNG facility that contains, controls, or processes gas or LNG.

(4) Any crack or other material defect that impairs the structural integrity or reliability of an underground natural gas facility or LNG facility that contains, controls, or processes gas or LNG.

(5) Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20% or more of its specified minimum yield strength or underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility.

(6) Any malfunction or operating error that causes the pressure—plus the margin (build-up) allowed for operation of pressure limiting or control devices—to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG.

(7) A leak in a pipeline or an underground natural gas facility including injection, withdrawal, monitoring, or observations well for an underground natural gas storage facility or LNG facility that contains or processes gas or LNG that constitutes an emergency.

(8) Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank.

(9) Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20% or more reduction in operating pressure or shutdown of operation of a pipeline or an underground natural gas facility including injection, withdrawal, monitoring, or observations well for an underground natural gas storage facility or an LNG facility that contains or processes gas or LNG.

10) For transmission pipelines only, each exceedance of maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§ 192.201, 192.620(e), and 192.739.
reporting requirement of this paragraph (a)(10) is not applicable to gathering lines, distribution lines, LNG facilities, or underground natural gas storage facilities. (See paragraph (a)(6) of this section.

(b) A report is not required for any safety-related condition that:
   (1) Exists on a master meter system or a customer-owned service line;
   (2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;
   (3) Exists on a pipeline (other than an LNG facility or Underground Natural Gas Storage Facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or
   (4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report. Notwithstanding this exception, a report must be filed for:
      (i) Conditions under paragraph (a)(1) of this section, unless the condition is localized corrosion pitting on an effectively coated and cathodically protected pipeline; and
      (ii) Any condition under paragraph (a)(10) of this section.


GUIDE MATERIAL

This guide material is under review following Amdt. 191-26.

(a) For the purpose of Safety-Related Condition Reports, "in-service facilities" are those that are pressurized with gas, regardless of flow conditions. Facilities that are not "in-service" are completely depressurized and isolated from all pressurized facilities by valves or physical separation.

(b) Section 192.605 requires operators to have procedures enabling O&M personnel to recognize conditions that potentially may be safety-related conditions. See Guide Material Appendix G-191-3 for a chart useful in determining if reports must be filed.

(c) See 4.4 of the guide material under §192.605 for actions to consider in response to safety-related conditions. See guide material under §192.617 for failure investigation, when applicable.

(d) If the MAOP plus the build-up allowed for operation of pressure-limiting or control devices on a transmission line is exceeded, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 ("Act")(Section 23(b)) states that the operator is to notify the Secretary of Transportation, and appropriate state agencies if the pipeline is subject to state regulations, on or before the fifth calendar day of the exceedance. PHMSA-OPS issued Advisory Bulletin ADB-2012-11 (77 FR 75699, Dec. 21, 2012; reference Guide Material Appendix G-192-1, Section 2) to advise owners and operators of gas transmission pipeline facilities of new reporting requirements in the Act. The Act states that exceedance is to be reported even if the condition is corrected within the reporting timeframe. The Advisory Bulletin requests operators to submit information comparable to that required for a safety-related condition (see Guide Material Appendix G-191-4). The operator should note that the reporting requirement for an exceedance is calendar days, as opposed to the safety-related conditions requirement of working days that does not include Saturdays, Sundays, or federal holidays.
§191.25
Filing safety-related condition reports.

(a) Each report of a safety-related condition under §191.23(a)(1) through (9) must be filed (received by the Associate Administrator) in writing within five working days (not including Saturday, Sunday, or Federal Holidays) after the day a representative of an 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. Separate conditions may be described in a single report if they are closely related. Reporting methods and report requirements are described in paragraph (c) of this section.

(b) Each report of a maximum allowable operating pressure exceedance meeting the requirements of criteria in §191.23(a)(10) for a gas transmission pipeline must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance using the reporting methods and report requirements described in paragraph (c) of this section.

(c) Reports must be filed by email to InformationResourcesManager@dot.gov or by facsimile to (202) 366-7128. For a report made pursuant to §191.23(a)(1) through (9), the report must be headed “Safety-Related Condition Report.” For a report made pursuant to §191.23(a)(10) the report must be headed “Maximum Allowable Operating Pressure Exceedances.” All reports must provide the following information:

1. Name, principal address, and operator identification number (OPID) of the operator.
2. Date of report.
3. Name, job title, and business telephone number of person submitting the report.
4. Name, job title, and business telephone number of person who determined that the condition exists.
5. Date condition was discovered and date condition was first determined to exist.
6. Location of condition, with reference to the State (and town, city, or county) or offshore site, and as appropriate, nearest street address, offshore platform, survey station number, milepost, landmark, or name of pipeline.
7. Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
8. The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

GUIDE MATERIAL

This guide material is under review following Amdt. 191-26.

(a) The preamble to Amendment 191-7 ("Interpretation and Statement of Policy Regarding Discovery of Safety-Related Conditions by Smart Pigs and Instructions to Personnel") states:
"Discovery of a potentially reportable condition occurs when an operator's representative has adequate information from which to conclude the probable existence of a reportable condition. An operator would have adequate information for each anomaly that is physically examined. Absent physical examination, discovery may occur after the data are calibrated if the "adequate information" test is met. However, the adequacy of the information that pig data provide about anomalous conditions is contingent on a concurrent indication from a number of factors from which an operator could conclude the probable existence of a reportable condition. Among these are the sophistication of the pig being used, the reliability of the data, the accuracy of data interpretation, and any other factors known by the operator relative to the condition of the pipeline."

(b) See Guide Material Appendix G-191-4 for a form useful for reporting a safety-related condition.

(c) Additional state requirements may exist for intrastate facilities.

191.27

Removed.  

Effective Date: 10/01/15]
§191.29

National Pipeline Mapping System.

[Effective Date: 10/01/15]

(a) Each operator of a gas transmission pipeline or liquefied natural gas facility must provide the following geospatial data to PHMSA for that pipeline or facility:


2. The name of and address for the operator.

3. The name and contact information of a pipeline company employee, to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator's NPMS data.

(b) The information required in paragraph (a) of this section must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, the operator must comply with the guidance provided in the NPMS Operator Standards manual available at www.npms.phmsa.dot.gov or contact the PHMSA Geographic Information Systems Manager at (202) 366-4595.

[Issued by Amdt. 191-23, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

No guide material necessary.
PART 192

MINIMUM FEDERAL SAFETY STANDARDS


SUBPART A
GENERAL

§192.1
What is the scope of this part?

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

(b) This part does not apply to—
(1) Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

(2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator’s facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9;

(3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;

(4) Onshore gathering of gas—
(i) Through a pipeline that operates at less than 0 psig (0 kPa);
(ii) Through a pipeline that is not a regulated onshore gathering line (as determined in §192.8); and

(iii) Within inlets of the Gulf of Mexico, except for the requirements in §192.612; or

(5) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—
(i) Fewer than 10 customers, if no portion of the system is located in a public place; or
(ii) A single customer, if the system is located entirely on the customer’s premises (no matter if a portion of the system is located in a public place).

15, 2006; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007]

GUIDE MATERIAL

1  GPTC GUIDE

(a) The guide material presented in this Guide includes information and some acceptable methods to assist the operator in complying with the Minimum Federal Safety Standards. The recommendations contained in the Guide are based on sound engineering principles, developed by a committee balanced in accordance with accepted committee procedures, and must be applied by the use of sound and competent engineering judgment. The guide material is advisory in nature and should not restrict the operator from using other methods of complying. In addition, the operator is cautioned that the guide material may not be adequate under all conditions encountered.

(b) While the GPTC Guide is intended principally to guide operators of natural gas pipelines, it is a valuable reference for operators of other pipelines covered by Part 192. The user is cautioned that the unique properties and characteristics associated with other gases (e.g., toxicity, density, corrosivity, and temperature extremes) may require special engineering, operations, and maintenance considerations. Also, the unique properties and toxicity of other gases can represent significant hazards that need to be considered but are not specifically addressed in the Guide. Operators of petroleum gas distribution systems and smaller natural gas systems (e.g., master meter operators) may benefit from information provided in the “Guidance Manual for Operators of LP Gas Systems” and “Guidance Manual for Operators of Small Natural Gas Systems” available at https://www.phmsa.dot.gov/training/pipeline/guidance-manuals.

(c) As used in the Guide, the terms Personnel, Employees, and Workers refer to operator employees and, unless specifically noted otherwise, include other personnel (e.g. contractors) used by operators to perform Part 192 functions.

2  STATE REQUIREMENTS


3  CONTRACTORS

The operator is responsible for the work of a contractor performing tasks covered under Part 192. The operator should ensure that contract personnel are familiar with applicable procedures prior to the start of work.

4  OFFSHORE PIPELINES

For offshore pipelines, responsibilities have been assigned to the Department of Transportation and the Department of the Interior in accordance with their Memorandum of Understanding dated December 10, 1996 (Implemented per Federal Register, Vol. 62, No. 223, November 19, 1997). See Guide Material Appendix G-192-19.

5  HYDROGEN PIPELINES


6  OSHA STANDARDS
The Occupational Safety and Health Administration has issued letters regarding application of their standards to working conditions that are regulated by PHMSA-OPS. See Guide Material Appendix G-192-21.

7 SPECIAL PERMITS

PHMSA-OPS considers applications from operators for special permits (waivers) under §190.341 to use new technologies, alternative design, materials, or inspection frequencies providing the resulting level of safety is comparable to or exceeds that in the current regulations. See guide material under §§192.107, 192.328, 192.611, 192.939, 192.943, and 192.1013.

*Note:* A “special permit” was previously referred to as a “waiver” by PHMSA-OPS. State terminology may differ (e.g., waiver, variance).

### §192.3

**Definitions.**

| Effective Date: 07/01/2020 |

As used in this part:

- *Abandoned* means permanently removed from service.

- *Active corrosion* means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.

- *Administrator* means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

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

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

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

- *Customer meter* means the meter that measures the transfer of gas from an operator to a consumer.

- *Distribution line* means a pipeline other than a gathering or transmission line.

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

- *Engineering critical assessment (ECA)* means a documented analytical procedure based on fracture mechanics principles, relevant material properties (mechanical and fracture resistance properties), operating history, operational environment, in-service degradation, possible failure mechanisms, initial and final defect sizes, and usage of future operating and maintenance procedures to determine the maximum tolerable sizes for imperfections based upon the pipeline segment maximum allowable operating pressure.

- *Exposed underwater pipeline* means 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.

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

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

- *Gulf of Mexico and its inlets* means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.
Hazard to navigation means, for the purposes of this part, 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 waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.

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

Line section 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.

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

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

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

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

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

Moderate consequence areas means:

(1) An onshore area that is within a potential impact circle, as defined in § 192.903, containing either:

(i) Five or more buildings intended for human occupancy; or

(ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration’s Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1 (see: https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classification/fcauab.pdf), and that does not meet the definition of high consequence area, as defined in § 192.903.

(2) The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, or any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

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

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

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

Outer Continental Shelf means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

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

Petroleum gas 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) gage at 100 °F (38 °C).

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

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

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

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

**Service line** 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** 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.

**SMYS** means specified minimum yield strength is:

1. For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or
2. For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b).

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

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

**Transmission line** means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a 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** means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

**Underground natural gas storage facility** means a facility that stores natural gas in an underground facility incident to natural gas transportation, including—

1. A depleted hydrocarbon reservoir;
2. An aquifer reservoir; or
3. A solution-mined salt cavern reservoir, including associated material and equipment used for injection, withdrawal, monitoring, or observation wells, and wellhead equipment, piping, rights-of-way, property, buildings, compressor units, separators, metering equipment, and regulator equipment.

**Weak link** means a device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stresses allowed.

**Welder** means a person who performs manual or semi-automatic welding.

**Welding operator** means a person who operates machine or automatic welding equipment.

GUIDE MATERIAL

Glossary of Commonly Used Terms
(For Glossary of Commonly Used Abbreviations, see Table 192.3i below.)

Abandoned pipeline is a pipeline that is physically separated from its source of gas and is no longer maintained under Part 192.

Abandonment is the process of abandoning a pipeline.

Adhesive joint is a joint made in thermosetting plastic piping by the use of an adhesive substance that forms a bond between the mating surfaces without dissolving either one of them.

Ambient temperature is the temperature of the surrounding medium, usually used to refer to the temperature of the air in which a structure is situated or a device operates. See also Ground Temperature and Temperature.

Bell-welded pipe is furnace-welded pipe that has a longitudinal butt joint that is forge-welded by the mechanical pressure developed in drawing the furnace-heated skelp through a cone-shaped die. The die, commonly known as a "welding bell," serves as a combined forming and welding die. This type of pipe is produced in individual lengths from cut-length skelp. Typical specifications: ASTM A53, API Spec 5L. See also Furnace-butt-welded pipe and Pipe manufacturing processes.

Bottle is a gastight structure that is (1) completely fabricated by the manufacturer from pipe with integral drawn, forged, or spun end closures; and (2) tested in the manufacturer's plant. See also Bottle-type holder.

Bottle-type holder is any bottle or group of interconnected bottles installed in one location, and used for the sole purpose of storing gas. See also Bottle.

Carbon steel. By common custom, steel is considered to be carbon steel where (i) 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; (ii) the specified minimum content for copper does not exceed 0.40 percent; or (iii) the specified maximum content does not exceed 1.65 percent for manganese, 0.60 percent for silicon or 0.60 percent 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. The unqualified term cast iron applies to gray-cast iron that 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.

Christmas tree is an assembly consisting of valves, fittings, pressure gauges, and connecting components used at ground level atop a wellhead to control the flow of gas into or out of the well.

Cold-expanded pipe is seamless or welded pipe that is formed and then, expanded in the pipe mill while cold, so that the circumference is permanently increased by at least 0.50 percent.

Compressor station is a pipeline facility installed for the purpose of mechanically increasing the gas pressure on a pipeline system or for reducing back-pressure on upstream gas facilities to enhance flow. Other facilities that might be located at the same site but not actually part of the compressor station include measurement, treatment, processing, and pressure control.

Continuous-welded pipe is furnace-welded pipe which has a longitudinal butt joint that is forge-welded by the mechanical pressure developed in rolling the hot-formed skelp through a set of round pass welding rolls. It is produced in continuous lengths from coiled skelp and subsequently cut into individual lengths. Typical specifications (see §192.7): ASTM A53, API Spec 5L. See also Furnace-butt-welded pipe and Pipe manufacturing processes.
Control piping is pipe, valves, and fittings used to interconnect air, gas, or hydraulically operated control apparatus.

Copper Tube Size (CTS) is an alphanumeric sizing convention for copper or plastic components comprised of the letters CTS preceded by a dimensionless number (e.g., ½ CTS). The CTS "size" is indirectly related to the nominal outside diameter used in the design of copper tubing (§192.125) or plastic tubing (§192.121). In all cases, the actual nominal outside diameter, using the CTS sizing convention, will measure 1/8 inch greater than the nominal CTS size. For example, ½ CTS tubing has an actual nominal outside diameter of 0.625 inches (0.500 + 0.125 inch).

Cross bore is an intersection of an existing underground utility or underground structure by a second utility. This typically occurs when the use of trenchless technology results in direct contact between utilities or underground structures that compromises the integrity of either.

Curb valve is a type of service-line valve installed for the purpose of shutting off gas supply. It is typically installed below grade at or near the property line.

Deactivation (Inactivation) is the process of making the pipeline inactive.

District regulator station or district pressure regulating station is a pressure regulating station that controls pressure to a high- or low-pressure distribution main. It does not include pressure regulation whose sole function is to control pressure to a manifold serving multiple customers.

Double submerged-arc-welded pipe is a pipe having longitudinal or spiral butt joints. The joints are produced by at least two passes, including at least one each on the inside and on the outside of the pipe. Coalescence is produced by heating with an electric arc or arcs between the bare metal electrode or electrodes and the work. The welding is shielded by a blanket or granular, fusible material on the work. Pressure is not used and filler metal for the inside and outside welds is obtained from the electrode or electrodes. Typical specifications (see §192.7): ASTM A381, API Spec 5L. See also Pipe manufacturing processes.

Dry gas is gas above its dew point and without condensed liquids.

Ductile iron (sometimes called nodular iron) is a cast ferrous material in which the free graphite present is in a spheroidal form rather than a flake form. The desirable properties of ductile iron are achieved by means of chemistry and a ferritizing heat treatment of the castings.

Electric-flash-welded pipe is pipe having a longitudinal butt joint wherein coalescence is produced simultaneously over the entire area of abutting 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. Typical specification (see §192.7): API Spec 5L. See also Pipe manufacturing processes.

Electric-fusion-welded pipe is 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. Typical specifications (see §192.7 and Guide Material Appendix G-192-1A): ASTM A134, ASTM A139: Single or double weld is permitted with or without the use of filler metal. ASTM A671, ASTM A672, ASTM A691, and API Spec 5L: Requires both inside and outside welds and use of filler metal.

Spiral-welded pipe is also made by the electric-fusion-welded process with either a butt joint, a lap joint, or a lock-seam joint. Typical specifications (see §192.7 and Guide Material Appendix G-192-1A): ASTM A134, ASTM A139, and API Spec 5L: Butt joint. ASTM A211: Butt joint, lap joint, or lock-seam joint. See also Pipe manufacturing processes.

Electric-resistance-welded (ERW) pipe is 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. It is produced in individual lengths or in continuous lengths from coiled skelp and subsequently cut into individual lengths. Typical specifications (see §192.7 and Guide Material Appendix G-192-1A): ASTM A53, ASTM A135, and API Spec 5L. See also Pipe manufacturing processes.

Electrolyte is a chemical substance containing ions that migrate in an electric field. Electrolytes can play a role in external corrosion or internal corrosion of metallic pipelines. For external corrosion, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged piping system, including the moisture and other chemicals contained therein. For internal corrosion, electrolyte refers to the chemicals contained in water inside the pipeline, including solutions of salts, acids, and bases.
**Electrolytic contact** (also known as an electrolytic couple or electrolytic short) is ionic contact between two metallic structures via an electrolyte.

**Excess Flow Valve (EFV)** is a device installed in a gas pipeline to automatically restrict or shut off the gas flow through the line when the flow exceeds a predetermined limit.

**Excess Flow Valve-Bypass (EFVB)** is an EFV that is designed to limit the flow of gas upon closure to a small, predetermined level. EFVBs reset automatically once the line downstream is made gastight and pressure is equalized across the valve.

**Excess Flow Valve-Non-Bypass (EFVNB)** is an EFV that is designed to stop the flow of gas upon closure. EFVNBs must be manually reset.

**Furnace-but-welded pipe.** There are two such types of pipe defined in this glossary: *Bell-welded pipe* and *Continuous-welded pipe*. See also *Pipe manufacturing processes*.

**Furnace-lap-welded pipe** is pipe that has a longitudinal lap joint that is produced by the forge welding process. In this process, coalescence is produced by heating a 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. Typical specification: API Spec 5L. The manufacture of this type of pipe was discontinued, and the process was deleted from API Spec 5L in 1962 (see §192.7 and Guide Material Appendix G-192-1A). See also *Pipe manufacturing processes*.

**Gas control** is a person or persons who acquire and maintain data to remotely monitor and direct the flow of gas to meet design and contractual obligations, and to assist in detecting pipeline emergencies and initiating response. See related definitions of *Control room* and *Controller* in §192.3.

**Ground temperature** is the temperature of the earth at pipe depth. See also *Ambient temperature* and *Temperature*.

**Heat-fusion joint** is a joint made in thermoplastic piping by heating the parts sufficiently to permit fusion of the materials when the parts are pressed together.

**Holiday** is a coating imperfection that exposes the pipe surface to the environment.

**Holiday detection** is testing of a coating for holidays using an instrument that applies a voltage between the external surface of the coating and the pipe.

**Hoop stress** is the stress in a pipe wall, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe, produced by the pressure of the fluid in the pipe. In this Guide, hoop stress in steel pipe is calculated by the formula:

\[ S_h = \frac{PD}{2t} \]

Where:
- \( S_h \) = Hoop stress, psi
- \( P \) = Internal pressure, psig
- \( D \) = Nominal outside diameter of pipe, inches
- \( t \) = Nominal wall thickness, inches

See also *Maximum allowable hoop stress*.

**Hot taps** are connections made to transmission lines, mains, or other facilities while they are in operation. The connecting and tapping is done while the facility is under gas pressure.

**Hydrostatic Design Basis (HDB)** is one of a series of established stress values specified in ASTM D2837, "Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products," for a plastic compound, obtained by categorizing the long-term hydrostatic strength as determined in accordance with ASTM D2837.

**Inactive pipeline** is a pipeline that is being maintained under Part 192 but is not presently being used to transport gas. See guide material under §192.727.

**Instrument piping** is pipe, valves, and fittings used to connect instruments to main piping, to other instruments and apparatus, or to measuring equipment.

**Iron.** See *Cast iron*, *Ductile iron*, and *Malleable iron*.

**Iron Pipe Size (IPS)** is an alphanumeric sizing convention for cast iron or plastic components comprised of the letters IPS followed by a dimensionless number (e.g., IPS 2). It was originally related to cast iron piping, but has been adopted by the plastic pipe specifications (i.e., ASTM D2513 - see §192.7) as a
plastic pipe sizing convention. IPS is not used for steel piping.

*Jeeping* is a method of *Holiday detection*.

**Joint.** See *Length*.

**Lateral line (transmission).** See guide material under §192.625.

*Leak surveys* are systematic inspections made for the purpose of finding leaks in a gas piping system. The types of inspections commonly made are described in Guide Material Appendix G-192-11 "Gas Leakage Control Guidelines for Natural Gas Systems" and Guide Material Appendix G-192-11A "Gas Leakage Control Guidelines for Petroleum Gas Systems."

**Length** is a piece of pipe as delivered from the mill. Each piece is called a length regardless of its actual longitudinal dimension. While this is sometimes called a "joint," the term "length" is preferred.

**Light surface oxide** is a non-damaging form of corrosion.

**Long-term hydrostatic strength (LTHS)** of plastic pipe is the estimated hoop stress, in psi, that would result in a failure of the pipe if the pipe were subjected to 100,000 hours of hydrostatic pressure.

**Lower Explosive Limit (LEL)** is the lower limit of flammability for a gas expressed as a percent, by volume, of gas in air.

**Malleable iron** is a mixture of iron and carbon, including small amounts of silicon, manganese, phosphorous, and sulfur which, after being cast, is converted structurally by heat treatment into primarily a matrix of ferrite containing nodules of tempered carbon.

**Maximum allowable hoop stress** is the maximum hoop stress permitted for the design of a piping system. It depends upon the material used, the class location of the pipe, and the operating conditions. See also *Hoop stress*.

**Maximum allowable test pressure** is the maximum internal fluid pressure permitted for testing, for the materials and class location involved.

**Metallic short** is direct metallic contact between two metallic structures.

**Meters.** See *Meter set assembly*.

**Meter set assembly** is that exposed portion of the service line extending from the service line riser valve to the connection of the customer's fuel line, including the meter, and (if present) the regulator and relief vent line. In the absence of a service line riser valve, the meter set assembly starts at the first exposed fitting. The meter set assembly does not include the customer's buried or exposed fuel line. If the operator's service line continues past the meter and connects to the customer's fuel line at a location some distance downstream of the meter, the meter set assembly ends at the meter outlet valve (if present) or at the first exposed fitting (e.g., coupling or union) downstream of the meter.

**Monitoring regulator** is 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.

**Nodular iron.** See *Ductile iron*.

**Nominal outside diameter (D)** is the outside diameter, in inches, as listed in Table 192.105i for nominal pipe size (NPS) 12 and less, and is the same as the nominal pipe size for greater than NPS 12. It is used in the design formula for steel pipe in §192.105 and the calculation for hoop stress. Steel, plastic in IPS and NPS sizes, and some types of cast iron pipe have the same nominal outside diameters. Matching diameters are used when replacing cast iron or steel pipe with plastic pipe. Table 192.121ii lists the outside diameters used in the design formula for copper or matching plastic pipe.

**Nominal Pipe Size (NPS)** is an alphanumeric sizing convention for steel and plastic components comprised of the letters NPS followed by a dimensionless number (e.g., NPS 2). NPS and IPS have the same nominal outside diameter for a given size. The NPS/IPS "number" originally represented the actual measured inside diameter of the piping, but this is not always true. The nominal outside diameter (D) used in the design formulas for NPS piping can be obtained from Table 192.105i or the various product specifications.

**Nominal wall thickness (t)** is the wall thickness, in inches, computed by, or used in, the design formula for steel pipe in §192.105. Pipe may be ordered to this computed wall thickness without adding an allowance to compensate for the under-thickness tolerances permitted in approved specifications.

**Operating stress** is the stress in a pipe or structural member under normal operating conditions.

**Otherwise changed** is a substantial physical alteration of a pipeline facility as opposed to a repair or restoration (Amdt. 192-102). The original alignment or functionality of the pipeline facility is modified by the alteration. Examples of a substantial physical alteration include the following.
(a) Addition of a pig launcher or receiver to a pipeline.
(b) Addition of a mainline block valve.
(c) Relocation of a pipeline.
(d) Connection of a lateral.

Overpressure protection is 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. See also Pressure limiting station, Pressure regulating station, and Pressure relief station.

Parallel encroachment pertains to that portion of the route of a transmission line or main that lies within, runs in a generally parallel direction to, and does not necessarily cross, the rights-of-way of a road, street, highway, or railroad.


Pipe-container is a gastight structure assembled from pipe and end closures. See also Pipe-type holder.

Pipe manufacturing processes. A reference is ASME I00396 “History of Line Pipe Manufacturing in North America.” Types and names of welded joints are used herein as defined in the American Welding Society (AWS) Publication A3.0 “Standard Welding Terms and Definitions” except for the following terms which are defined in this glossary.

Bell-welded pipe
Continuous-welded pipe
Double-submerged-arc-welded pipe
Electric-flash-welded pipe
Electric-fusion-welded pipe
Electric-resistance-welded pipe
Furnace-butt-welded pipe
Furnace-lap-welded pipe
Seamless pipe

Pipe-type holder is any pipe-container or group of interconnected pipe-containers installed at one location for the sole purpose of storing gas. See also Pipe-container.

Plastic (noun) is a material that contains one or more organic polymeric substances of high molecular weight as an essential ingredient, is solid in its finished state, and can be shaped by flow at some stage of its manufacture or processing into finished articles. The two general types of plastic referred to in this Guide are thermoplastic and thermosetting. See also Thermoplastic and Thermosetting plastic.


Pressure (expressed in pounds per square inch above atmospheric pressure, i.e., gauge pressure (abbreviation: psig), unless otherwise stated). See also Maximum allowable test pressure, Overpressure protection, Pressure limiting station, Pressure regulating station, Pressure relief station, and Standup pressure test.

Pressure limiting station consists of apparatus which, under abnormal conditions, 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 gas 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. 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 regulating station consists of apparatus 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 consists of apparatus installed to vent 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 station are any enclosures and
ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.

Private rights-of-way are those that are not located on roads, streets, or highways used by the public, or on railroad rights-of-way.

Proprietary items are items made by a company having the exclusive right of manufacture.

Public place is a place that is generally open to all persons in a community as opposed to being restricted to specific persons. A public place includes churches, schools, and commercial property, as well as any publicly owned right-of-way or property that is frequented by people.

Public road, street, or highway is a general term denoting a public way for the purpose of vehicular travel, including the entire area within its right-of-way.

Reference datum is a known and constant surface which is used to describe the location of points on the earth. The most common reference datum sets used in North America are NAD27, NAD83, and WGS84.

Regulators. See Pressure limiting station, Pressure regulating station, and Pressure relief station.

Right-of-way is a general term denoting land, property, or interest therein, usually in a strip, acquired for or devoted to specific purpose such as a highway or pipeline.

Sample piping is pipe, valves, and fittings used for the collection of samples of gas or other fluids.

Seamless pipe is 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. See also Pipe manufacturing processes.

Secondary stress is stress created in the pipe wall by loads other than internal fluid pressure. Examples are backfill loads, traffic loads, beam action in a span and loads at supports and at connections to the pipe.

Service-line valve is a valve located in a service line and meets the requirements of §192.363. A service-line valve may be a curb valve, or other valve, located upstream of the:

(a) service regulator,
(b) meter and any meter bypass, where there is no service regulator, or
(c) connection to customer piping if there is no meter.

Slack loop is extra pipe length installed to counter the effects of pipe expansion and contraction.

Solvent cement joint is a joint made in PVC piping by using solvent cement to join the piping components.

Standup pressure test is 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.

Steel is an iron-base alloy, malleable in some temperature range as initially cast, containing manganese, carbon, and often other alloying elements. See also Carbon steel.

Stress is the resultant internal force that resists change in the size or shape of a body acted on by external forces. See also Hoop stress, Maximum allowable hoop stress, Operating stress, Secondary stress, Tensile strength, and Yield strength.

Stress corrosion cracking of metallic pipe is the formation of cracks, typically in a colony or cluster, as a result of the interaction of tensile stress, a corrosive environment, and a susceptible material.

Subject Matter Experts (SMEs) are persons knowledgeable about design, construction, operations, maintenance, or characteristics of a pipeline system. Designation as an SME does not necessarily require specialized education or advanced qualifications. Some SMEs may possess such expertise, but detailed knowledge of the pipeline system gained by working with it over time can also make someone an SME. SMEs may be employees, consultants, contractors, or any suitable combination of these.

Subsurface safety valve (SSSV) is a downhole device installed in the production (flow) string of a well to prevent uncontrolled flow from a well in the event of an emergency. An SSSV may be surface-controlled or subsurface-controlled.

Temperature (expressed in degrees Fahrenheit (°F) unless otherwise stated). See also Ambient temperature and Ground temperature.

Tensile strength is the highest unit tensile stress (referred to the original cross section) that a material can sustain before failure (psi)

Thermoplastic is a plastic that is capable of being repeatedly softened by increase of temperature and hardened by decrease of temperature. Examples of thermoplastic materials include polyethylene (PE), polyamid (PA or nylon), and polyvinyl chloride (PVC).

Thermosetting plastic is a plastic that is capable of being changed into a substantially infusible or insoluble product when cured under the application of heat or by chemical means. Examples of thermosetting
plastic materials include:
(a) Epoxy as used in epoxy fiberglass pipe, “Red Thread®” pipe, and fiber-reinforced pipe (FRP); and
(b) Unsaturated polyester as used in fiberglass composites for steel pipe repair sleeves, and cured-in-place (CIP).

Thickness. See Nominal wall thickness.

Valve. See Curb valve and Service-line valve.

Vault is an underground structure which may be entered, and which is designed to contain piping and piping components, such as valves or pressure regulators.

Wellhead is a structure installed at the surface of a gas well to provide the structural and pressure-containing interface between the subsurface casing strings and the surface facilities including the Christmas tree.

Yield strength is the strength at which a material exhibits a specified limiting permanent set, or produces a specified total elongation under load. The specified limiting set or elongation is usually expressed as a percentage of gage length, and its values are specified in the various material specifications acceptable under this Guide.

### GLOSSARY OF COMMONLY USED ABBREVIATIONS

*Note: For added organizational abbreviations, see Guide Material Appendix G-192-1, Sections 4 and 5.*

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>ABS</td>
<td>acrylonitrile-butadiene-styrene</td>
</tr>
<tr>
<td>ACVG</td>
<td>alternating current voltage gradient</td>
</tr>
<tr>
<td>AOC</td>
<td>abnormal operating condition</td>
</tr>
<tr>
<td>ASV</td>
<td>automatic shut-off valve</td>
</tr>
<tr>
<td>BAP</td>
<td>baseline assessment plan</td>
</tr>
<tr>
<td>CAB</td>
<td>cellulose acetate butyrate</td>
</tr>
<tr>
<td>CDA</td>
<td>confirmatory direct assessment</td>
</tr>
<tr>
<td>CGI</td>
<td>combustible gas indicator</td>
</tr>
<tr>
<td>CIS</td>
<td>close-interval survey</td>
</tr>
<tr>
<td>CP</td>
<td>cathodic protection</td>
</tr>
<tr>
<td>CTS</td>
<td>copper tube size</td>
</tr>
<tr>
<td>DA</td>
<td>direct assessment</td>
</tr>
<tr>
<td>DCVG</td>
<td>direct current voltage gradient</td>
</tr>
<tr>
<td>DIMP</td>
<td>Distribution Integrity Management Program</td>
</tr>
<tr>
<td>ECDA</td>
<td>external corrosion direct assessment</td>
</tr>
<tr>
<td>EFV</td>
<td>excess flow valve</td>
</tr>
<tr>
<td>EFVB</td>
<td>excess flow valve – bypass (automatic reset)</td>
</tr>
<tr>
<td>EFVNB</td>
<td>excess flow valve – non-bypass (manual reset)</td>
</tr>
<tr>
<td>ERW</td>
<td>electric resistance welded</td>
</tr>
<tr>
<td>ESD</td>
<td>emergency shutdown</td>
</tr>
<tr>
<td>FAQ</td>
<td>frequently asked question</td>
</tr>
<tr>
<td>FBE</td>
<td>fusion bonded epoxy</td>
</tr>
<tr>
<td>FRP</td>
<td>fiberglass reinforced plastic</td>
</tr>
<tr>
<td>GIS</td>
<td>geographic information system</td>
</tr>
<tr>
<td>GMA</td>
<td>Guide Material Appendix</td>
</tr>
<tr>
<td>GPS</td>
<td>global positioning system</td>
</tr>
<tr>
<td>H₂S</td>
<td>hydrogen sulfide</td>
</tr>
<tr>
<td>HCA</td>
<td>high consequence area</td>
</tr>
<tr>
<td>HDB</td>
<td>hydrostatic design basis</td>
</tr>
<tr>
<td>HFI</td>
<td>hydrogen flame ionization</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Meaning</td>
</tr>
<tr>
<td>--------------</td>
<td>---------</td>
</tr>
<tr>
<td>IBR</td>
<td>Incorporated by reference (see §192.7)</td>
</tr>
<tr>
<td>IC</td>
<td>internal corrosion</td>
</tr>
<tr>
<td>ICDA</td>
<td>internal corrosion direct assessment</td>
</tr>
<tr>
<td>ICS</td>
<td>Incident Command System</td>
</tr>
<tr>
<td>ILI</td>
<td>in-line inspection</td>
</tr>
<tr>
<td>IMP</td>
<td>integrity management program</td>
</tr>
<tr>
<td>IPS</td>
<td>iron pipe size</td>
</tr>
<tr>
<td>IR drop</td>
<td>voltage drop</td>
</tr>
<tr>
<td>LEL</td>
<td>lower explosive limit</td>
</tr>
<tr>
<td>LNG</td>
<td>liquefied natural gas</td>
</tr>
<tr>
<td>LPG</td>
<td>liquid or liquefied petroleum gas</td>
</tr>
<tr>
<td>LTHS</td>
<td>long-term hydrostatic strength</td>
</tr>
<tr>
<td>MAOP</td>
<td>maximum allowable operating pressure</td>
</tr>
<tr>
<td>MIC</td>
<td>microbiologically influenced corrosion</td>
</tr>
<tr>
<td>MOC</td>
<td>management of change</td>
</tr>
<tr>
<td>MOP</td>
<td>maximum operating pressure</td>
</tr>
<tr>
<td>MRS</td>
<td>minimum required strength</td>
</tr>
<tr>
<td>NAPSRO</td>
<td>National Association of Pipeline Safety Representatives</td>
</tr>
<tr>
<td>NDE</td>
<td>nondestructive evaluation</td>
</tr>
<tr>
<td>NPS</td>
<td>nominal pipe size</td>
</tr>
<tr>
<td>O₂</td>
<td>oxygen</td>
</tr>
<tr>
<td>O&amp;M</td>
<td>operations and maintenance</td>
</tr>
<tr>
<td>OCS</td>
<td>outer continental shelf</td>
</tr>
<tr>
<td>OQ</td>
<td>operator qualification</td>
</tr>
<tr>
<td>PA</td>
<td>polyamide</td>
</tr>
<tr>
<td>P&amp;M measures</td>
<td>preventive and mitigative measures</td>
</tr>
<tr>
<td>PDB</td>
<td>pressure design basis</td>
</tr>
<tr>
<td>PE</td>
<td>polyethylene</td>
</tr>
<tr>
<td>PIC</td>
<td>potential impact circle</td>
</tr>
<tr>
<td>PIR</td>
<td>potential impact radius</td>
</tr>
<tr>
<td>PVC</td>
<td>poly (vinyl chloride), also written as polyvinyl chloride</td>
</tr>
<tr>
<td>RCV</td>
<td>remote control valve</td>
</tr>
<tr>
<td>SCADA</td>
<td>supervisory control and data acquisition</td>
</tr>
<tr>
<td>SCC</td>
<td>stress corrosion cracking</td>
</tr>
<tr>
<td>SCCDA</td>
<td>stress corrosion cracking direct assessment</td>
</tr>
<tr>
<td>SDB</td>
<td>strength design basis</td>
</tr>
<tr>
<td>SDR</td>
<td>standard dimension ratio</td>
</tr>
<tr>
<td>SME</td>
<td>subject matter expert</td>
</tr>
<tr>
<td>SMYS</td>
<td>specified minimum yield strength</td>
</tr>
<tr>
<td>USGS</td>
<td>United States Geological Survey</td>
</tr>
<tr>
<td>USCG</td>
<td>United States Coast Guard</td>
</tr>
</tbody>
</table>

**TABLE 192.3i**
§192.5
Class locations.

(a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.

(1) A "class location unit" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline.

(2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:

(1) A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

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

(3) A Class 3 location is:

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

(ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

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

(c) The length of Class locations 2, 3, and 4 may be adjusted as follows:

(1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.

(2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.

(d) An operator must have records that document the current class location of each pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.


GUIDE MATERIAL

This guide material is under review following Amendment 192-125.
§192.7

What documents are incorporated by reference partly or wholly in this part?

[Effective Date: 07/01/2020]

(a) This part prescribes standards, or portions thereof, incorporated by reference into this part with the approval of the Director of the Federal Register in 5 U.S.C. 552(a) and 1 CFR part 51. The materials listed in this section have the full force of law. To enforce any edition other than that specified in this section, PHMSA must publish a notice of change in the Federal Register.

1. Availability of standards incorporated by reference. All of the materials incorporated by reference are available for inspection from several sources, including the following:
   (i) The National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email fedreg.legal@nara.gov or go to www.archives.gov/federal-register/cfr/ibr-locations.html.
   (iii) Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

2. [Reserved]

IBR approved for:


<p>| (5) API Recommended Practice 1162, “Public Awareness Programs for Pipeline Operators,” 1st edition, December 2003, (API RP 1162). | §192.616(a), (b), and (c). |
| (7) API Specification 5L, “Specification for Line Pipe,” 45th edition, effective July 1, 2013, (API Spec 5L). | §§192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192. |</p>
<table>
<thead>
<tr>
<th>IBR approved for: (Continued)</th>
</tr>
</thead>
<tbody>
<tr>
<td>§192.145(a).</td>
</tr>
<tr>
<td>§192.147(c).</td>
</tr>
<tr>
<td>§192.147(a) and 192.279 and 192.607(f).</td>
</tr>
<tr>
<td>Item I, Appendix B to Part 192.</td>
</tr>
<tr>
<td>§192.112(b) and 192.619(a).</td>
</tr>
<tr>
<td>§192.903 note to Potential impact radius; 192.907 introductory text, (b); 192.911 introductory text, (l), (k), (l), (m), 192.913(a), (b), (c); 192.917(a), (b), (c), (d), (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b), (c); 192.929(b); 192.933(c), (d); 192.935(a), (b); 192.937(c); 192.939(a); and 192.945(a).</td>
</tr>
<tr>
<td>IBR approved for: (Continued)</td>
</tr>
<tr>
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</tr>
<tr>
<td>(8) ASME Boiler &amp; Pressure Vessel Code, Section VIII, Division 1 “Rules for Construction of Pressure Vessels,” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1).</td>
</tr>
<tr>
<td>(d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800-222-2768, website: <a href="https://www.asnt.org/">https://www.asnt.org/</a>.</td>
</tr>
<tr>
<td>(2) [Reserved]</td>
</tr>
<tr>
<td>IBR approved for: (Continued)</td>
</tr>
<tr>
<td>---</td>
</tr>
<tr>
<td>(12) ASTM D2517–00, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings,” (ASTM D 2517).</td>
</tr>
</tbody>
</table>
Addendum 5, December 2019

**GPTC GUIDE FOR GAS TRANSMISSION, DISTRIBUTION,**
**AND GATHERING PIPING SYSTEMS: 2018 Edition**

**SUBPART A**

<table>
<thead>
<tr>
<th>Item</th>
<th>Description</th>
<th>Section(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(f)</td>
<td>Gas Technology Institute (GTI, formerly the Gas Research Institute GRI), 1700 S. Mount Prospect Road, Des Plaines, IL 60018, phone: 847–768–0500, Web site: <a href="http://www.gastechnology.org">www.gastechnology.org</a>.</td>
<td>§192.927(c).</td>
</tr>
<tr>
<td>(h)</td>
<td>NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084, phone: 281–228–6223 or 800–797–6223, Web site: <a href="http://www.nace.org/Publications/">http://www.nace.org/Publications/</a>.</td>
<td>§§ 192.150(a) and 192.493</td>
</tr>
</tbody>
</table>

§§192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).

(2) [Reserved]


§192.121.

(2) PPI TR–4 HDB/HDS/SDB/MRS, Listed Materials, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB), and Minimum Required Strength (MRS) Rating for Thermoplastic Piping Materials or Pipe," Updated March, 2011. (PPI TR–4/2012)

§192.121.


GUIDE MATERIAL

This guide material is under review following Amendments 192-119, 192-124 and 192-125.

(a) Additional standards and specifications recommended for use under this Guide, and the names and addresses of the sponsoring organizations, are shown in Guide Material Appendix G-192-1. See Guide Material Appendix G-192-1A for documents previously incorporated by reference in the Regulations.

(b) Operators are cautioned that significant changes have been made between the 43rd and 44th editions of API Spec 5L. Significant changes include pipe dimensions, manufacturing tolerances, chemical composition, welding methods, inspection criteria, and pipe grade naming conventions.

Note: For additional information regarding the changes, see API’s comparison document referenced in API’s letter dated August 2008, “Re: Comparison of API Spec 5L 43rd edition and ISO 3183 (2nd ed.) /API Spec 5L 44th edition.” Revised edition titled “Detailed comparison of API 5L (43rd) & API 5L (44th) Requirements,” printed June 9, 2009 and available at:

www.api.org/certification-programs/api-monogram-program-and-apiqr/~media/166147045384dc5a4a236373cddfe4a8.ashx

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### §192.9

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Compliance deadline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Establish MAOP under §192.619.</td>
<td>October 15, 2007</td>
</tr>
<tr>
<td>Install and maintain line markers under §192.707.</td>
<td>April 15, 2008</td>
</tr>
<tr>
<td>Establish a public education program under §192.616</td>
<td>April 15, 2008</td>
</tr>
<tr>
<td>Other provisions of this part as required by paragraph (c) of this section for Type A lines.</td>
<td>April 15, 2009</td>
</tr>
</tbody>
</table>

(3) If, after April 14, 2006, a change in class location or increase in dwelling density causes an onshore gathering line to be a regulated onshore gathering line, the operator has 1 year for Type B lines and 2 years for Type A lines after the line becomes a regulated onshore gathering line to comply with this section.


### §192.10

**Outer continental shelf pipelines.**

[Effective Date: 03/08/05]

Operators of transportation pipelines on the Outer Continental Shelf (as defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331) must identify on all their respective pipelines the specific points at which operating responsibility transfers to a producing operator. For those instances in which the transfer points are not identifiable by a durable marking, each operator will have until September 15, 1998 to identify the transfer points. If it is not practicable to durably mark a transfer point and the transfer point is located above water, the operator must depict the transfer point on a schematic located near the transfer point. If a transfer point is located subsea, then the operator must identify the transfer point on a schematic which must be maintained at the nearest upstream facility and provided to PHMSA upon request. For those cases in which adjoining operators have not agreed on a transfer point by September 15, 1998 the Regional Director and the MMS Regional Supervisor will make a joint determination of the transfer point.

[Issued by Amtd. 192-81, 62 FR 61692, Nov. 19, 1997 with Amtd. 192-81 Confirmation, 63 FR 12659, Mar. 16, 1998; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005]

### GUIDE MATERIAL

No guide material necessary.

Addendum 5, December 2019 43
§192.11
Petroleum gas systems.

(a) Each plant that supplies petroleum gas by pipeline to a natural gas distribution system must meet the requirements of this part and NFPA 58 and NFPA 59 (incorporated by reference, see §192.7).

(b) Each pipeline system subject to this part that transports only petroleum gas or petroleum gas/air mixtures must meet the requirements of this part and ANSI/NFPA 58 and 59.

(c) In the event of a conflict between this part and NFPA 58 and 59 (incorporated by reference, see §192.7), NFPA 58 and NFPA 59 prevail.


GUIDE MATERIAL

1 GENERAL

1.1 Introduction.

Personnel involved in the design, construction, operation, and maintenance of petroleum gas systems should be thoroughly familiar with the applicable provisions of the Federal Regulations and referenced NFPA Standards (see §192.7 for IBR).

Figure 192.11A depicts the standards applicable to petroleum gas plants that supplement natural gas systems, as described in §192.11(a).

![Diagram of Petroleum Gas Systems](image-url)
compliance with a provision of the recommended practice is not practicable and not necessary for safety with respect to specified underground storage facilities or equipment. The justifications for any deviation from any provision of API RP 1170 and API RP 1171 must be technically reviewed and documented by a subject matter expert to ensure there will be no adverse impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety and must be dated and approved by a senior executive officer, vice president, or higher office with responsibility of the underground natural gas storage facility. An operator must discontinue use of any variance where PHMSA determines and provides notice that the variance adversely impacts design, construction, operations, maintenance, integrity, emergency preparedness and response, or overall safety.

[Amdt. 192-122, 81 FR 91873, Dec. 19, 2016]

GUIDE MATERIAL

Note: This guide material is based upon the adoption of an Interim Final Rule (81 FR 91860, December 19, 2016, effective January 18, 2017). PHMSA issued a Stay of Enforcement (82 FR 28224, June 20, 2017) to consider issues raised in comments received and to announce the suspension of enforcement citations for a period of one year after the Final Rule is published.

1 API RP 1170 AND API RP 1171 (See §192.7 for IBR)
Guidance provided in API RP 1170 for solution-mined salt caverns and API RP 1171 for depleted hydrocarbon reservoirs and aquifer reservoirs used for the underground storage of natural gas is represented as “recommended practices.” However, §192.12(f) requires the operator to follow the general program recommendations of API RP 1170 or API RP 1171, as applicable, unless the operator justifies in its written program or procedural manual why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

2 REFERENCES
(a) National standards and the sections referencing them in API RP 1170 and API RP 1171 are as follows.

<table>
<thead>
<tr>
<th>National Standard</th>
<th>API RP 1170</th>
<th>API RP 1171</th>
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</thead>
<tbody>
<tr>
<td>API Bulletin 5A2, Bulletin on Thread Compounds for Casing, Tubing, and Line Pipe</td>
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<tr>
<td>API Bulletin E3, Well Abandonment and Inactive Well Practices</td>
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<td>6.7.1</td>
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<tr>
<td>API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines</td>
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<td>6.5.3</td>
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<tr>
<td>API Guidance Document HF2, Water Management Associated with Hydraulic Fracturing</td>
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<td>6.5.3</td>
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<tr>
<td>API Guidance Document HF3, Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing</td>
<td></td>
<td>6.5.3</td>
</tr>
<tr>
<td>API RP 5A3, Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements</td>
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<td>8.4.2.6</td>
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<tr>
<td>API RP 5A5, Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe</td>
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<tr>
<td>API RP 5B1, Gauging and Inspection of Casing, Tubing and Line Pipe Threads</td>
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<tr>
<td>API RP 5C1, Recommended Practice for Care and Use of Casing and Tubing</td>
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<td>8.4.2.5</td>
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<tr>
<td>API RP 10D-2, Recommended Practice for Centralizer Placement and Stop-collar Testing</td>
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<td>6.4.5</td>
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<tr>
<td>API RP 10F, Recommended Practice for Performance Testing of Cementing Float Equipment</td>
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<td>2, 7.6.1</td>
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<tr>
<td>National Standard</td>
<td>API RP 1170</td>
<td>API RP 1171</td>
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<tr>
<td>API RP 13D, Rheology and Hydraulics of Oil-well Drilling Fluids</td>
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<tr>
<td>API RP 14B, Design, Installation, Repair and Operation of Subsurface Safety Valve Systems</td>
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<td>6.2.5</td>
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<tr>
<td>API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems</td>
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<td>6.3.5</td>
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<tr>
<td>API RP 49, Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide</td>
<td></td>
<td>6.8.1</td>
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<tr>
<td>API RP 51R, Environmental Protection for Onshore Oil and Gas Production Operations and Leases</td>
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<td>5.5.1, 6.8.1</td>
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<td>API RP 53, Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells</td>
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<td>11.5.2</td>
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<tr>
<td>API RP 54, Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations</td>
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<td>6.8.1, 11.5.2, 11.6.2</td>
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<td>API RP 76, Contractor Safety Management for Oil and Gas Drilling and Production Operations</td>
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<tr>
<td>API RP 1114, Recommended Practice for the Design of Solution-Mined Underground Storage Facilities</td>
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<tr>
<td>API RP 1115, Design and Operation of Solution-mined Salt Caverns Used for Liquid Hydrocarbon Storage</td>
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<tr>
<td>API Specification 5CT, Specification for Casing and Tubing</td>
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<td>API Specification 5DP, Specification for Drill Pipe</td>
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<td>API Specification 5L, Specification for Line Pipe</td>
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<td>API Specification 6A, Specification for Wellhead and Christmas Tree Equipment</td>
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<td>API Specification 6D, Specification for Pipeline Valves</td>
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<td>API Specification 10A, Specification for Cements and Materials for Well Cementing</td>
<td>2, 7.6.1</td>
<td>6.4.2, 6.7.2</td>
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<tr>
<td>API Specification 14A, Specification for Subsurface Safety Valve Equipment</td>
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<td>6.2.5</td>
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<tr>
<td>API Standard 65-2, Isolating Potential Flow Zones during Well Construction</td>
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<td>6.4.5</td>
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<tr>
<td>API Standard 1104, Welding of Pipelines and Related Facilities</td>
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<tr>
<td>API Technical Report 5C3, Calculating Performance Properties of Pipe Used as Casing or Tubing</td>
<td>2, 8.4.2.3</td>
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<tr>
<td>API Technical Report 10TR1, Cement Sheath Evaluation</td>
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<td>6.4.6</td>
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<tr>
<td>API Technical Report 10TR4, Selection of Centralizers for Primary Cementing Operations</td>
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<td>6.4.5</td>
</tr>
<tr>
<td>ASTM C150/C150M, Standard Specification for Portland Cement</td>
<td></td>
<td>6.4.2, 6.7.2</td>
</tr>
<tr>
<td>ASTM D3740, Standard Practice for Minimum Requirements for Agencies Engaged in Testing and/or Inspection of Soil and Rock as Used in Engineering Design and Construction</td>
<td></td>
<td>5.4.2.1</td>
</tr>
<tr>
<td>ASTM D3967, Standard Test Method for Splitting Tensile Strength of Intact Rock Core Specimens</td>
<td>2, 5.4.2.4</td>
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<tr>
<td>ASTM D4543, Standard Practices for Preparing Rock Core as Cylindrical Test Specimens and Verifying Conformance to Dimensional and Shape Tolerances</td>
<td>2, 5.4.2.3</td>
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<tr>
<td>ASTM D4645, Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method</td>
<td>2, 5.4.4</td>
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</tbody>
</table>
TABLE 192.12-1 (Continued)

<table>
<thead>
<tr>
<th>National Standard</th>
<th>API RP 1170</th>
<th>API RP 1171</th>
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<tbody>
<tr>
<td>ASTM D7012, Standard Test Methods for Compressive Strength and Elastic Moduli of</td>
<td>2, 5.4.2.5.1,</td>
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<tr>
<td>Intact Rock Core Specimens under Varying States of Stress and Temperatures</td>
<td>5.4.2.5.2,</td>
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<td>5.4.2.5.3</td>
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<tr>
<td>ASTM D7070, Standard Test Methods for Creep of Rock Core Under Constant Stress</td>
<td>2, 5.4.2.6</td>
<td>6.7.2</td>
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<td>and Temperature</td>
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<td>U.S. Bureau of Safety and Environmental Enforcement Report</td>
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<td>RLS0116, Cement Plug Testing: Weight vs pressure Testing to Assess Viability of a</td>
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<td>Wellbore Seal between Zones</td>
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<td>* Standard referenced in API</td>
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<td>associated with another</td>
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<tr>
<td></td>
<td>particular section.</td>
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</tbody>
</table>

(b) For additional guidance on managing risk for gas storage operations, the operator may refer to the following:

4. ASME B31.8S, Managing System Integrity of Gas Pipelines.

3 COMPLIANCE DATES FOR EXISTING STORAGE FACILITIES

3.1 Solution-mined Salt Cavern Reservoirs
Each underground natural gas storage facility constructed not later than July 18, 2017 that uses a solution-mined salt cavern reservoir for natural gas storage must meet the requirements and recommendations of the following sections of API RP 1170 by January 18, 2018 (§192.12(b)).

(a) Section 9, Gas Storage Operations, for operations, maintenance, site security, emergency response and preparedness, and associated records.
(b) Section 10, Cavern Integrity Monitoring, for integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, and associated records.
(c) Section 11, Cavern Abandonment, and associated records.

3.2 Depleted Hydrocarbon and Aquifer Reservoirs
Each underground natural gas storage facility constructed not later than July 18, 2017 that uses a depleted hydrocarbon reservoir or an aquifer reservoir for natural gas storage must meet the requirements and recommendations of the following sections of API RP 1171 by January 18, 2018 (§192.12(d)).

(a) Section 8, Risk Management for Gas Storage Operations, for operations, maintenance, and associated records.
(b) Section 9, Integrity Demonstration, Verification, and Monitoring, for integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, and associated records.
(c) Section 10, Site Security and Safety, Site Inspections, and Emergency Preparedness and Response, for site security, emergency response and preparedness, and associated records.
(d) Section 11, Procedures and Training, and associated records.
§192.13
What general requirements apply to pipelines regulated under this part?
[Effective Date: 04/14/06]

(a) No person may operate a segment of pipeline listed in the first column that is readied for service after the date in the second column, unless:
(1) The pipeline has been designed, installed, constructed, initially inspected, and initially tested in accordance with this part; or
(2) The pipeline qualifies for use under this part according to the requirements in §192.14.

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until April 14, 2006.</td>
<td>March 15, 2007.</td>
</tr>
<tr>
<td>All other pipelines.</td>
<td>March 12, 1971.</td>
</tr>
</tbody>
</table>

(b) No person may operate a segment of pipeline listed in the first column that is replaced, relocated, or otherwise changed after the date in the second column, unless the replacement, relocation or change has been made according to the requirements in this part.

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until April 14, 2006.</td>
<td>March 15, 2007.</td>
</tr>
<tr>
<td>All other pipelines.</td>
<td>November 12, 1970.</td>
</tr>
</tbody>
</table>

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


GUIDE MATERIAL

See Guide Material Appendix G-192-17. Also, see the "Glossary of Commonly Used Terms" under §192.3 for definition of "otherwise changed."

§192.14
Conversion to service subject to this part.
[Effective Date: 03/24/17]

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:
(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation.

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

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

(4) The pipeline must be tested in accordance with Subpart J of this part to substantiate the maximum allowable operating pressure permitted by Subpart L of this part.

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

(c) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 191.22 of this chapter.


GUIDE MATERIAL

1 TYPES

The following are some of the types of steel pipelines that might be converted to gas service under this part.

(a) Gas pipelines abandoned prior to effective date of Part 192.

(b) Liquid petroleum pipelines, such as oil or gasoline.

(c) LPG pipeline systems.

(d) Nonjurisdictional pipelines.

(e) Pipelines carrying chemical or industrial products, such as carbon dioxide, nitrogen, air or liquid chemicals.

(f) Slurry pipelines.

2 TESTS AND INSPECTION

The following are examples of appropriate tests and inspections that may be used to evaluate pipelines where sufficient historical records are not available. See §192.14(a)(1).

(a) Corrosion surveys.

(b) Ultrasonic inspections.

(c) Acoustic emissions.

(d) Tensile tests. See Appendix B to Part 192.

(e) Internal inspections.

(f) Radiographic inspections.

(g) Pressure tests. See §192.619(a)(1).

3 VISUAL INSPECTION OF UNDERGROUND SEGMENTS

Generally, the segments to be inspected should be at locations where the worst probable conditions may be expected. The following criteria should be used for the selection of inspection sites.

(a) Corrosion surveys (inadequately protected segments, poor coating, stray currents, and interference).

(b) Pipeline component locations.

(c) Locations subject to mechanical damage.

(d) Foreign pipeline crossings.

(e) Locations subject to damage due to chemicals, such as acid.

(f) Segments subject to coating deterioration due to soil stresses and internal or external temperature extremes.
§192.15
Rules of regulatory construction.  

(a) As used in this part:
Includes means including but not limited to.
May means "is permitted to" or "is authorized to".
May not means "is not permitted to" or "is not authorized to".
Shall is used in the mandatory and imperative sense.
(b) In this part:
(1) Words importing the singular include the plural;
(2) Words importing the plural include the singular; and
(3) Words importing the masculine gender include the feminine.

GUIDE MATERIAL

No guide material necessary.

§192.16
Customer notification.  

(a) This section applies to each operator of a service line who does not maintain the customer's buried piping up to entry of the first building downstream, or, if the customer's buried piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment. For the purpose of this section, "customer's buried piping" does not include branch lines that serve yard lanterns, pool heaters, or other types of secondary equipment. Also, "maintain" means monitor for corrosion according to §192.465 if the customer's buried piping is metallic, survey for leaks according to §192.723, and if an unsafe condition is found, shut off the flow of gas, advise the customer of the need to repair the unsafe condition, or repair the unsafe condition.
(b) Each operator shall notify each customer once in writing of the following information:
(1) The operator does not maintain the customer's buried piping.
(2) If the customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
(3) Buried gas piping should be-
   (i) Periodically inspected for leaks;
   (ii) Periodically inspected for corrosion if the piping is metallic; and
   (iii) Repaired if any unsafe condition is discovered.
(4) When excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand.
(5) The operator (if applicable), plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping.
(c) Each operator shall notify each customer not later than August 14, 1996, or 90 days after the customer first receives gas at a particular location, whichever is later. However, operators of master meter systems may continuously post a general notice in a prominent location frequented by
customers.

(d) Each operator must make the following records available for inspection by the Administrator or a state agency participating under 49 U.S.C. 60105 or 60106:

(1) A copy of the notice currently in use; and

(2) Evidence that notices have been sent to customers within the previous 3 years.


GUIDE MATERIAL

No guide material necessary.

§192.17
(removed.)
[Effective Date: 07/20/81]

§192.18
How to notify PHMSA.
[Effective Date: 07/01/2020]

(a) An operator must provide any notification required by this part by –(1) Sending the notification by electronic mail to InformationResourcesManager@dot.gov; or (2) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor E22-321, 1200 New Jersey Ave. SE Washington, DC 20590.,

(b) An operator must also notify the appropriate State or local pipeline safety authority when an applicable pipeline segment is located in a State where OPS has an interstate agent agreement, or an intrastate applicable pipeline segment is regulated by the State.

(c) Unless otherwise specified, if the notification is made pursuant to § 192.506(b), § 192.607(e)(4), § 192.607(e)(5), § 192.624(c)(2)(iii), § 192.624(c)(6), § 192.632(b)(3), § 192.710(c)(7), § 192.712(d)(3)(iv), § 192.712(e)(2)(i)(E), § 192.921(a)(7), or § 192.937(c)(7) to use a different integrity assessment method, analytical method, sampling approach, or technique (i.e, “other technology”) that differs from that prescribed in those sections, the operator must notify PHMSA at least 90 days in advance of using the other technology. An operator may proceed to use the other technology 91 days after submittal of the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposed use of other technology or that PHMSA requires additional time to conduct the review.

[Issued by Amdt. 192-125, Oct. 1, 2019]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125.
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§192.63

GUIDE MATERIAL

This guide material is under review following Amendment 192-124.

(a) The manufacturer marks the pipe and fittings with the maximum temperature at which the pipe and fittings have been qualified for use. For example: PE 2406/PE 2708 CDC - The first letter following the 4-digit number designates the maximum temperature at which the piping material's hydrostatic design basis (HDB) has been established and, thus, the maximum temperature at which the pipe can be used. The second letter indicates the HDB for the piping material at that maximum temperature and the third letter is the categorized melt index (actual values are listed in ASTM D2513 - see §192.7 for IBR). The first letter designations from ASTM D2513 are as follows.

A=100 °F
B=120 °F
C=140 °F
D=160 °F
E=180 °F

Note: The HDB expresses the long-term strength of a thermoplastic material in terms of a series of standard strength categories (e.g., 1600 psi, 1250 psi, 1000 psi) which have been established in accordance with ASTM D2837. Specific HDBs can be obtained from the manufacturer and from the Plastics Pipe Institute (PPI).

(b) Thermoplastic pipe manufactured prior to August 16, 1978 may not be marked with the appropriate code letters for elevated temperature operation. Operators who have installed such pipe should take proper precautions to ensure the pipe is used only within the actual temperature and stress limits for which it was tested and qualified. See §192.123(b)(2).

(c) Marking requirements for PE pipe manufactured after March 6, 2015 are described in ASTM D2513-09a. All other new installations of thermoplastic materials must meet the ASTM D2513-87 (see §192.7 for IBR) marking requirements (§192.63(a)).

§192.65

Transportation of pipe.

[Effective Date: 10/01/15]

(a) Railroad. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by railroad unless the transportation is performed by API RP 5L1 (incorporated by reference, see §192.7).

(b) Ship or barge. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that
is transported by ship or barge on both inland and marine waterways unless the transportation is performed in accordance with API RP 5LW (incorporated by reference, see §192.7).

(c) **Truck.** In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not use pipe having an outer diameter to wall thickness ratio of 70 to 1, or more, that is transported by truck unless the transportation is performed in accordance with API RP 5LT (incorporated by reference, see § 192.7).


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**GUIDE MATERIAL**

*No guide material necessary*

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**§192.67**

Records: Material properties

[Effective Date: 07/01/20]

(a) For steel transmission pipelines installed after [July 1, 2020], an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §§ 192.53 and 192.55. Records must include tests, inspections and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records that document tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition in accordance with §§ 192.53 and 192.55, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of the pipeline segment, the operator may be subject to the requirements of § 192.624 according to the terms of that section.

[Amend 192-125, Oct. 1, 2019]

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**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*
§192.69
Storage and handling of plastic pipe and associated components
[Effective Date: 01/22/19]

Each operator must have and follow written procedures for the storage and handling of plastic pipe and associated components that meet the applicable listed specifications.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

No guide material available at present.
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5 PLASTIC PIPE MANUFACTURED BEFORE MAY 18, 1978

The following language was removed from §192.123(b)(2)(i) by Amendment 192-93:

"However, if the pipe was manufactured before May 18, 1978 and its long-term hydrostatic strength was determined at 73 °F (23 °C), it may be used at temperatures up to 100 °F (38 °C)."

This language permitted the installation and operation of plastic pipe manufactured prior to May 18, 1978, at temperatures up to 100 °F using the 73 °F HDB. This sentence was removed since this vintage plastic pipe is no longer available nor is it still being installed. However, pipe installed under this clause is "grandfathered" and can continue to be operated at temperatures up to 100 °F using the 73 °F HDB.

6 MECHANICAL FITTINGS

ASTM Subcommittee F17.60 publishes the following specifications to qualify mechanical fittings that connect plastic pipe for design temperatures from -20 °F to 140 °F.
(a) ASTM F1924, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing."
(b) ASTM F1948, "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing."

7 INSTALLATION OF PA-11 PIPING FOR HIGHER PRESSURE APPLICATIONS

See 9 of the guide material under §192.321.
§192.125  
Design of copper pipe.  

[Effective Date: 07/13/98]

(a) Copper pipe used in mains must have a minimum wall thickness of 0.065 inches (1.65 millimeters) and must be hard drawn.  
(b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

<table>
<thead>
<tr>
<th>Standard size inch (millimeter)</th>
<th>Nominal O.D. inch (millimeter)</th>
<th>Wall thickness inch (millimeter)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal</td>
<td>Tolerance</td>
<td></td>
</tr>
<tr>
<td>1/2 (13)</td>
<td>0.625 (16)</td>
<td>0.040 (1.06)</td>
</tr>
<tr>
<td>5/8 (16)</td>
<td>0.750 (19)</td>
<td>0.042 (1.07)</td>
</tr>
<tr>
<td>3/4 (19)</td>
<td>0.875 (22)</td>
<td>0.045 (1.14)</td>
</tr>
<tr>
<td>1 (25)</td>
<td>1.125 (29)</td>
<td>0.050 (1.27)</td>
</tr>
<tr>
<td>1 1/4 (32)</td>
<td>1.375 (35)</td>
<td>0.055 (1.40)</td>
</tr>
<tr>
<td>1 1/2 (38)</td>
<td>1.625 (41)</td>
<td>0.060 (1.52)</td>
</tr>
</tbody>
</table>

c) Copper pipe used in mains and service lines may not be used at pressures in excess of 100 p.s.i. (689 kPa) gage.  
d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft³ (6.9/m³) under standard conditions. Standard conditions refers to 60 °F and 14.7 psia (15.6 °C and one atmosphere) of gas.


GUIDE MATERIAL

See §192.377 for additional requirement regarding copper service lines.

§192.127  
Records: Pipe design.  

[Effective Date: 07/01/20]

(a) For steel transmission pipelines installed after July 1, 2020], an operator must collect or make, and retain for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with § 192.103 and documenting that the determination of design pressure for the pipe is made in accordance with § 192.105.  
(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting pipe design and the determination of design pressure in accordance with §§ 192.103 and 192.105, operators must retain such records for the life of the pipeline.
(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of the § 192.624 according to the terms of that section.

[Amdt 192-125, Oct. 1, 2019]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125.
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§192.150

Passage of internal inspection devices.

[Effective Date: 07/01/2020]

(a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, see §192.7).

(b) This section does not apply to:

(1) Manifolds;
(2) Station piping such as at compressor stations, meter stations, or regulator stations;
(3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;
(4) Cross-overs;
(5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;
(6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;
(7) Offshore transmission lines, except transmission lines 10 ¼ inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless —

(i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or
(ii) If the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices; and
(8) Other piping that, under §190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.

(c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (a) of this section, if the operator determines and documents why and impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under §190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.


GUIDE MATERIAL

This guide material is under review following Amendment 192-125.

REFERENCES
§192.151
Tapping.

[Effective Date: 07/13/98]

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

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

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

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

(2) A 1¼-inch (32 millimeters) tap may be made in a 4-inch (102 millimeters) cast iron or ductile iron pipe, without reinforcement. However, in areas where climate, soil, and service conditions may create unusual external stresses on cast iron pipe, unreinforced taps may be used only on 6-inch (152 millimeters) or larger pipe.

[Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 DESIGN

1.1 Proprietary fittings.

(a) General. When using proprietary hot tap fittings, the operator should ensure that the pressure-temperature rating, installation procedure and service restrictions have been established in accordance with sound engineering principles. The fittings should be used only in accordance with the manufacturer's recommendations.

(b) Pressure-temperature ratings. Published catalog or engineering data supplied by a reputable manufacturer or designer is usually sufficient. When the rating cannot be so established, it should be established by test in accordance with paragraph UG-101 of Section VIII of the ASME Boiler and Pressure Vessel Code (see §192.7).

1.2 Other fittings.

For design requirements for hot tap fittings fabricated by welding, see §192.153.

1.3 Branch connection.

For hot taps involving branch connections, see guide material under §192.155.

2 PRESSURE LIMITATIONS

Tapping equipment can have a maximum working pressure rating less than the fitting and less than the actual operating pressure of the pipeline being tapped. In that event, the operating pressure must be temporarily reduced during the tapping operation. If, in an emergency, a fitting is not qualified for the MAOP of the pipeline, the operating pressure must be lowered to the pressure rating of the fitting and must be maintained at or below this level until the fitting is removed.
regulator, the relief capacity may be based on the maximum capacity of the pipeline system supplying the station.

2 DETERMINATION OF RELIEF DEVICE CAPACITY

(a) When installed in accordance with the provisions of §192.199(f):
   (1) Relief devices stamped by the manufacturer with a capacity certified under the rules of Section VIII of the ASME Boiler and Pressure Vessel Code (see §192.7), including recertification stampings, may be considered capable of relieving the capacity stamped. An adjustment should be made to determine the capacity at actual operating conditions.
   (2) Capacities listed in information published by the manufacturer may be used to identify the capacity of the relief device under the stated conditions.
   (3) The use of published data or data otherwise obtained from the manufacturer, and data calculated using recognized formulas, is acceptable.

(b) Relief device capacities as set out above are normally based on the pressure measured at the inlet to the relief device with discharge to atmosphere without vent stack piping. Therefore, when the installation is not in accordance with the provisions of §192.199(f), consideration should be given to the pressure loss in the inlet piping to the relief device, the control piping location and back pressure on the discharge side caused by vent stack piping.

(c) References include the following.
   (1) For the calculations in 2(a)(3) above, UG-131 of Section VIII of the ASME Boiler and Pressure Vessel Code. It is not the intent herein that the capacity be limited to 90% of the actual capacity as set out in Section VIII rules, but only that this information is useful in calculating the actual capacity of a relief device.
   (2) For data on relief devices which have been certified by the NBBI, "Relieving Capacities of Safety Valves and Relief Valves Approved by the National Board" (Discontinued).
   (3) For the effect of backpressure on relief device discharge, Figure D-1 of API RP 520 P2, "Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part 2 Installation."

§192.203
Instrument, control, and sampling pipe and components.
[Effective Date: 07/13/98]

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

(b) Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following:
   (1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.
   (2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.
   (3) Brass or copper material may not be used for metal temperatures greater than 400 °F (204 °C).
   (4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.
   (5) Pipe or components in which liquids may accumulate must have drains or drips.
   (6) Pipe or components subject to clogging from solids or deposits must have suitable
connections for cleaning.

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

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

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


GUIDE MATERIAL

Instrument, control, and sampling pipe and components which extend to a remote location (adjacent room or building) should be identified by color code, signs, diagrams, or other appropriate means so that proper valves can be located and operated in an emergency. At locations where the identification of such piping is obvious, color coding, marking, diagrams, etc., may not be necessary. Also, see Guide Material Appendix G-192-13 and 3.3 of the guide material under §192.199.

§192.204

Risers installed after January 22, 2019.

[Effective Date: 01/22/19]

(a) Riser designs must be tested to ensure safe performance under anticipated external and internal loads acting on the assembly.

(b) Factory assembled anodeless risers must be designed and tested in accordance with ASTM F1973–13 (incorporated by reference, see § 192.7).

(c) All risers used to connect regulator stations to plastic mains must be rigid and designed to provide adequate support and resist lateral movement. Anodeless risers used in accordance with this paragraph must have a rigid riser casing.

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

No guide material available at present.
§192.205
Records: Pipeline components.

[Effective Date: 07/01/2020]

(a) For steel transmission pipelines installed after July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records documenting the manufactured and tested in accordance with this subpart. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.

(b) For steel transmission pipelines installed on or before July 1, 2020, if operators have records documenting the manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches, operators must retain such records for the life of the pipeline.

(c) For steel transmission pipeline segments installed on or before July 1, 2020, if an operator does not have records necessary to establish the MAOP of a pipeline segment, the operator may be subject to the requirements of §192.624 according to the terms of that section.

[Amtd. 192-125, Oct. 1, 2019]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125.
§192.221 Scope.
[Effective Date: 11/12/70]

(a) This subpart prescribes minimum requirements for welding steel materials in pipelines.
(b) This subpart does not apply to welding that occurs during the manufacture of steel pipe or steel pipeline components.

GUIDE MATERIAL

Welding terms used in this Guide generally conform to the standard definitions established by the American Welding Society and contained in AWS Publication A3.0 "Standard Welding Terms and Definitions." See definition of "Pipe Manufacturing Processes" in the guide material under §192.3 for exceptions.

§192.223 (Removed.)
[Effective Date: 07/07/86]

§192.225 Welding procedures.
[Effective Date: 03/24/17]

(a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see §192.7) or section IX of the ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §192.7), to produce welds meeting the requirements of this subpart. The quality of the test welds used to qualify welding procedures must be determined by destructive testing in accordance with the applicable welding standard(s).

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

GUIDE MATERIAL

(a) An additional reference for welding procedures is.
    ASME B31.8, "Gas Transmission and Distribution Piping Systems."

(b) Information on preheating and stress relieving of welded connections can be found in the above references. Preheating and stress relieving should be performed in accordance with the qualified welding procedure being used.

§192.227
Qualification of welders.
[Effective Date: 07/01/2020]

(a) Except as provided in paragraph (b) of this section, each welder or welding operator must be qualified in accordance with section 6, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see §192.7), or section IX of the ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §192.7). However, a welder or welding operator qualified under an earlier edition than the edition listed in §192.7 of this part may weld but may not requalify under that earlier edition.

(b) A welder may qualify to perform welding on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS by performing an acceptable test weld, for the process to be used, under the test set forth in section I of Appendix C of this part. Each welder who is to make a welded service line connection to a main must first perform an acceptable test weld under section II of Appendix C of this part as a requirement of the qualifying test.

(c) For steel transmission pipe installed after July 1, 2021, records demonstrating each individual welder qualification at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.


GUIDE MATERIAL

This guide material is under review following Amendment 192-125.

It is the operator’s responsibility to ensure that all welding is performed by qualified welders and welding operators. The ability of welders and welding operators to make sound welds should be determined by test welds using previously qualified welding procedures. The evaluation of test welds may be conducted by qualified operator personnel or testing laboratories.
(x) Joining or repair technique. See 3 of the guide material under §192.281.
(2) Qualification. The procedure specification should be considered qualified if test assemblies of joints or repairs made in accordance with the procedure specification meet the requirements of 2.2 below. The test assemblies should be cured, set, or hardened in accordance with the manufacturer's recommendations.

(b) Mechanical. (Plastic-to-plastic and plastic-to-metal)
(1) Procedure. A separate procedure should be established for each kind and type of mechanical fitting to be used for making a joint or repair. It should include at least the following.
(i) Kind and type of plastic material(s).
(ii) Other piping elements to be joined to the plastic.
(iii) Joint design.
(iv) Size and thickness range.
(v) Type of mechanical fitting.
(vi) Tools and equipment.
(vii) Joining and repair procedure.
(2) Qualification. To qualify the procedure specification, test assemblies of joints or repairs should be made in accordance with the procedure specifications and tested in accordance with 2.2 below. The test assemblies may be restrained to the same extent that they would be in service. These assemblies should be sectioned or dismantled to inspect for damage to the plastic pipe. The procedure should be rejected if there is evidence of damage that would reduce the service life of an installed joint or repair.
(3) Other considerations. See 3.5 of the guide material under §192.281.

2.2 Test requirements. (Plastic-to-plastic and plastic-to-metal)
Test assemblies should successfully meet the following requirements.
(a) Leak test. An assembly should not leak when subjected to a stand-up pressure test with air or gas.
(b) Short-term burst test. An assembly should meet the minimum burst requirements of ASTM D2513 or ASTM D2517, whichever is applicable (see §192.7 for both), for the specific kind and size of plastic pipe used in the assembly.
(c) Sustained-pressure test. An assembly should not fail when subjected to a sustained pressure test, such as the 1000 hr test described in ASTM D2513 or ASTM D2517 (whichever is applicable), for the specific kind and size of plastic pipe used in the assembly.
(d) Inspection. An assembly should be subjected to suitable nondestructive or destructive inspection to determine if the bonded area is substantially equivalent to the intended bond area.

3 UNLIKE PE COMPONENT QUALIFICATION

PE components made of different compounds and different grades of materials may be heat-fused, provided that properly qualified procedures for joining the specific compounds are used. Any combination of PE 2306, PE 2406/PE 2708, PE 3306, PE 3406, and PE 3408/PE 4710 may be joined by heat fusion using qualified procedures for specific materials. Operators attempting to qualify such procedures may be able to obtain qualified procedures from pipe manufacturers. (See guide material under §192.281 for PE heat fusion.) Additionally, the following references may be of assistance.
(a) PPI TN-13, "General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings."
(b) PPI TR-33, "Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe."
(c) PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."
§192.285 Plastic pipe: Qualifying persons to make joints.  [Effective Date: 01/22/19]

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by —
   (1) Appropriate training or experience in the use of the procedure; and
   (2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.

(b) The specimen joint must be —
   (1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
   (2) In the case of a heat fusion, solvent cement, or adhesive joint:
      (i) Tested under any one of the test methods listed under §192.283(a) or for PE heat fusion joints (except for electrofusion joints) visually inspected and tested in accordance with ASTM F2620–12 (incorporated by reference, see § 192.7) applicable to the type of joint and material being tested;
      (ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
      (iii) Cut into at least 3 longitudinal straps, each of which is —
         (A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
         (B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.

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

(e) For transmission pipe installed after July 1, 2021, records demonstrating each person's plastic pipe joining qualifications at the time of construction in accordance with this section must be retained for a minimum of 5 years following construction.


GUIDE MATERIAL

This guide material is under review following Amendment 192-124 and 192-125.

1 OBSERVATION AND CERTIFICATION OF JOINER

Persons qualifying to make joints in plastic piping should be observed and certified by a qualified joiner while demonstrating their ability to make satisfactory joints using the correct procedure. See AGA XR0603, "Plastic Pipe Manual for Gas Service."

2 CERTIFICATION RECORDS

Addendum 5, December 2019
Records or qualification cards or both, which show the extent of the individual's qualifications, should be maintained for the qualification interval.

3 ULTRASONIC INSPECTION OF FUSION JOINTS

Ultrasonic inspection equipment should be capable of inspecting the internal bead for proper formation as well as detecting flaws in the fusion zone. Each manufacturer is a source of procedures for its equipment. The criteria for establishing an acceptable fusion joint must be verified by a destructive test and be repeatable. Each procedure should include the following.
(a) Cleaning the inspection area on both sides of the fusion joint.
(b) Using an appropriate manufacturer-approved couplant to couple the transducer to the pipe.
(c) Inspecting the entire pipe circumference on both sides of the fusion joint.

§192.287
Plastic pipe: Inspection of joints.
[Effective Date: 07/14/04]

No person may carry out the inspection of joints in plastic pipes required by §§192.273(c) and 192.285(b) unless that person has been qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedure.


GUIDE MATERIAL

No guide material available at present.
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§192.491
Corrosion control records.
[Effective Date: 07/08/96]

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode. 

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465(a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service.


GUIDE MATERIAL

In addition to the specific requirements of §192.491, the data contained in the records or maps used for corrosion control should include the following.

(a) Location of test stations.
(b) Location of rectifiers and groundbeds.
(c) Location of galvanic anodes.
(d) Location of corrosion control facilities, such as insulating flanges or connections, bonds, automatic switches, and diodes.
(e) Readings of pipe-to-soil potential.
(f) Length and location of cathodically protected segments of piping.
(g) Location of unprotected metallic piping.
(h) Date cathodic protection facilities placed in service.
§192.493
In-line inspection of pipelines. [Effective Date: 07/01/2020]

When conducting in-line inspections of pipelines required by this part, an operator must comply with API STD 1163, ANSI/ASNT ILI-PQ, and NACE SP0102, (incorporated by reference, see § 192.7). Assessments may be conducted using tethered or remotely controlled tools, not explicitly discussed in NACE SP0102, provided they comply with those sections of NACE SP0102 that are applicable.

[Amdt. 192-125, Oct. 1, 2019]

GUIDE MATERIAL

This guide material is under review following Amdt. 192-125.
thermometers, deadweight pressure gauges, meters, etc. be used and that the readings be taken at properly located points and at proper intervals of time.

4.2 Test procedure.
It is recommended that pressure in the test segment be applied in increments equal to 25% of the total test pressure. At the end of each incremental increase, the pressure should be maintained while the test segment is checked for leaks or other sources of rapid decline in pressure.

4.3 Locating leaks.
The location of leaks may be determined visually, by sound, by smell, or by utilizing leak detection equipment. The leak detection method to be used is dependent upon the test media. Caution - multiple leaks may exist.

4.4 Repairs.
It may be prudent to lower pressure in the test segment prior to exposing the pipe for repair. While temporary repairs may be made to accommodate the test, permanent repairs must satisfy requirements of §§192.309, 192.711, 192.713, 192.715, and 192.717 as applicable.

5 RECORDS
See guide material under §192.517.

§192.506
Transmission lines: Spike hydrostatic pressure test.
[Effective Date: 07/01/2020]

(a) Spike test requirements. Whenever a segment of steel transmission pipeline that is operated at a hoop stress level of 30 percent or more of SMYS is spike tested under this part, the spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with this section.

1) The test must use water as the test medium.
2) The baseline test pressure must be as specified in the applicable paragraphs of §192.619(a)(2) or §192.620(a)(2), whichever applies.
3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours as specified in §192.505.
4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the lesser of 1.5 times MAOP or 100% SMYS. This spike hydrostatic pressure test must be held for at least 15 minutes after the spike test pressure stabilizes.

(b) Other technology or other technical evaluation process. Operators may use other technology or another process supported by a documented engineering analysis for establishing a spike hydrostatic pressure test or equivalent. Operators must notify PHMSA 90 days in advance of the assessment or reassessment requirements of this subchapter. The notification must be made in accordance with §192.18 and must include the following information:

1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;
§192.50

Addendum 5, December 2019

243(a)
§192.509

Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.
[Effective Date: 07/13/98]

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated below 100 p.s.i. (689 kPa) gage must be leak tested in accordance with the following:

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

(b) Each main that is to be operated at less than 1 p.s.i. (6.9 kPa) gage must be tested to at least 10 p.s.i. (69 kPa) gage and each main to be operated at or above 1 p.s.i. (6.9 kPa) gage must be tested at least 90 p.s.i. (621 kPa) gage.

[Ammd. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL

See 1(b) of the guide material under §192.505; guide material under §§192.515 and 192.517; and Guide Material Appendix G-192-9.

2 TEST DURATION

(a) See 4(a) and (b) of the guide material under §192.513.

(b) An example of an approach to determine the test durations for steel pipe at typical diameters and lengths is presented in Table 192.509i. These durations do not include the time to pressurize the test segments, time for temperature stabilization, or the time for depressurizing the test segments. The test period should begin when the pressure of the test medium stabilizes.

(c) The time required to reach the test pressure and temperature stabilization depends on several factors, including pipe diameter, pipe length, whether the pipe segment is buried or exposed to the atmosphere, and the initial temperatures of the test segment, pressurizing medium, and the environment around the test segment.

(d) Temperature variations during the test period could affect the gauge pressure and should be considered.
2.2 Tests in excess of 50 percent SMYS.
When the test will result in hoop stresses in excess of 50% SMYS, particularly in uprating facilities, each operator should consider the following precautionary measures to ensure that the test area is kept clear of persons not directly engaged in the testing operation.
(a) Placing caution signs or barriers along the pipeline route wherever deemed appropriate, such as at roads and public corridors. These should be supplemented by security patrols or guards or both in residential areas, industrial areas and at river crossings.
(b) Aerial surveillance of the pipeline route, when practical, to monitor activity in the test area when testing with natural gas, inert gas or air.
(c) Notifying parties located in the general vicinity of the pipeline to avoid the test area during the period of the test.
(d) Notifying law enforcement agencies, fire departments, state and county highway departments, railroad and utility companies with facilities in the test area and, as applicable, airport operators regarding the scope and period of the test.
(e) When the test is being conducted in high exposure areas, consideration should be given to the following.
   (1) Scheduling the test at a time to minimize public exposure.
   (2) Limiting the length of the test section to minimize potential hazards.

2.3 Tests in excess of 90 percent SMYS.
When the test pressure will produce a hoop stress in excess of 90% of SMYS, the following additional precautions may be considered to minimize the risk to occupants of buildings in close proximity to the pipeline.
(a) Using pre-tested pipe.
(b) Pre-testing the segment.
(c) Using energy absorbing devices (e.g., sandbag barriers, backfill, piling, and walls).

3 HAZARDS ASSOCIATED WITH FILLING AND DEWATERING PIPELINES FOR HYDROSTATIC TESTING
(a) During the filling and dewatering processes, significant and sudden variations in pressure may occur within the pipeline and the temporary filling and dewatering piping. These variations can be caused by changes in velocity of the pig passing through bends in the pipeline or of the pig and water due to changes in pipeline elevation. Compressed air escaping around a pig can also create a source for stored energy within the pipeline. The release of this stored energy, as well as surges transferred from the pipeline to the temporary filling and dewatering piping, can result in pipe movement.
(b) When conducting a hydrostatic test, the following should be considered when filling and dewatering pipelines.
   (1) Prepare a detailed test plan that includes the required equipment, test duration, and test pressure.
   (2) Conduct training for the individuals involved with the test that includes a review of the test and dewatering plan, instructions on the filling/dewatering system installation and techniques, and proper coupling and anchoring methods.
   (3) Perform an engineering analysis of the existing and temporary piping systems to identify the forces that could adversely affect the integrity of the pipeline, the integrity of temporary fill piping, or the integrity and stability of the drainage components, such as excessive or variable pressures caused by a stuck pig or leaks. An engineering analysis may consist of the following.
      (i) Designing the temporary piping system within the parameters of the hydrostatic pressure test. Consider factors such as the diameter and pressure rating of the temporary piping system (including couplings and fittings), the joining method, and the piping geometry.
(ii) Accounting for hydrostatic head pressure caused by changes in elevation.
(iii) Considering pressure variations or thrust due to changes in direction at bends, elbows, and dead-ends.
(iv) Determining the proper joining method for the temporary piping system.
(4) Develop installation techniques that address forces expected during the filling, testing, and dewatering operations. Those techniques would include effective anchoring systems that prevent pipe movement, separation, or whipping. Piping components (e.g., couplings, flanges, valves) should be free of damage and installed in accordance with manufacturer’s instructions.
(5) Inspect temporary pipe, couplings, and fittings to ensure they are in good condition and rated for the pressure and temperature conditions specified for the test.
(6) Ensure that anchoring and support systems are installed in accordance with the plan.
(7) Control access to the area around the test site by establishing a limited-access zone to keep out persons not involved with the test.
(c) For additional background information on this subject, see OPS Advisory Bulletin ADB-04-01 (69 FR 58225, Sept. 29, 2004; reference Guide Material Appendix G-192-1, Section 2).

4 ENVIRONMENTAL CONSIDERATIONS

Each operator, in fulfilling the local, state, and federal environmental regulations with respect to the disposal of the test medium, should, among other things, give consideration to the following.
(a) Selecting water from satisfactory sources.
(b) Mitigating erosion and flooding of the area where the water is being discharged.
(c) Using filters, impoundment facilities or other appropriate methods to ensure that the atmosphere and the surface waters are not unnecessarily contaminated by the products being discharged.
(d) Using silencers, during the blowdown operation, where sound might be generated which is objectionable to area residents.
(e) Scheduling and locating the blowdown to minimize public objection to the noise generated.

§192.517
Records.
[Effective Date: 07/01/2020]

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505, 192.506 and 192.507. The record must contain at least the following information:
   (1) The operator’s name, the name of the operator’s employee responsible for making the test, and the name of any test company used.
   (2) Test medium used.
   (3) Test pressure.
   (4) Test duration.
   (5) Pressure recording charts, or other record of pressure readings.
   (6) Elevation variations, whenever significant for the particular test.
   (7) Leaks and failures noted and their disposition.
(b) Each operator must maintain a record of each test required by §§192.509, 192.511, and 192.513 for at least 5 years.

[Amtd. 192-93, 68 FR 53895, Sept. 15, 2003; Amtd. 192-125, Oct. 1, 2019]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125.
(a) In addition to the requirements of §192.517(a), records of a pressure test should include the following.
   (1) Start and completion times of the test.
   (2) Name of the person responsible for performing the test and the person who approved the test, if different.
   (3) A detailed description of the segment of pipeline and associated components that were tested, which should include:
      (i) For station piping, a diagram of the station that identifies the location of the tested segment;
      (ii) For a pipeline, the segment length using mile markers, stationing, or other location description;
      (iii) For pipeline components, the type, size, locations, and pressure ratings; and
      (iv) For all tested pipe, the following.
         (A) Outside diameter.
         (B) Wall thickness.
         (C) Pipe grade or designation.
         (D) Pipe material.
         (E) Joint types.
         (F) Seam type.

(b) Records of a successful hydrostatic pressure test might include the following in addition to that listed under (a) above.
   (1) Minimum and maximum elevation values, including the calculated test pressure, measured test pressure, or both at the control point as well as the highest and lowest points.
   (2) Temperatures recorded throughout the duration of the test.
      (i) Ambient air.
      (ii) Underground (restrained) piping.
      (iii) Aboveground (unrestrained) piping.
   (3) Liquid volume injected, withdrawn, or both, during the test.
   (4) Pressure versus volume plot.
      Note: To confirm that the test did not reveal any leaks or yield the pipe, taking into consideration the thermal effects on unrestrained piping throughout the duration of the test.

(c) For pre-November 12, 1970 pipelines, operators might not have pressure test records that meet all of the current requirements under §192.517(a). In the event a pressure test was conducted prior to that date, an operator may consider several different types of records that verify a pressure test was conducted. Preferably, those records would include a date and signature of the individual who witnessed the test. Any one or combination of the following records may be considered.
   (1) Test pressure records, including charts or other forms indicating pressure recordings.
   (2) Job-specific pressure test plan and procedure.
   (3) Notation of completion of pressure test requirements on as-built drawings.
   (4) Field notes or log books with details of testing.
   (5) An operator form with details of the pressure test.
   (6) Other documents that the operator deems appropriate per their specific standards.

(d) For tests conducted under §§192.509, 192.511, or 192.513, records are required to show that the tests have been conducted. The date, location of the test, and the test pressure applied may be sufficient documentation. Additional information may be included at the discretion of the operator.

(e) For segments of steel service line stressed to 20% or more of SMYS (§192.511(c)), records are required to document testing in accordance with §192.507.

(f) For a non-welded joint used to tie in a pipeline, the operator should have a record demonstrating that a leak test was performed at not less than the operating pressure (see §192.503(d)).
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(b) If the MAOP verification indicates changes to MAOP are necessary, the operator should consider the following actions.

(1) Assessing the impact to the pipeline system.
(2) Identifying a remediation strategy for addressing deficiencies.
(3) Revising the operator’s pipeline records, which may include:
   (i) manual for operations, maintenance, and emergencies.
   (ii) gas control records.
   (iii) gas control alarms.
   (iv) GIS.
   (v) electronic databases.
   (vi) other records and documents where the operator may record pipeline MAOP data.
(4) Communicating the change to the appropriate operator personnel.
(5) Reviewing and revising overpressure protection requirements.
(6) Identifying potential reporting requirements.

§192.607
Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.
[Effective Date: 07/01/2020]

(a) **Applicability.** Wherever required by this part, operators of onshore steel transmission pipelines must document and verify material properties and attributes in accordance with this section.

(b) **Documentation of material properties and attributes.** Records established under this section documenting physical pipeline characteristics and attributes, including diameter, wall thickness, seam type, and grade (e.g., yield strength, ultimate tensile strength, or pressure rating for valves and flanges, etc.), must be maintained for the life of the pipeline and be traceable, verifiable, and complete. Charpy v-notch toughness values established under this section needed to meet the requirements of the ECA method at § 192.624(c)(3) or the fracture mechanics requirements at § 192.712 must be maintained for the life of the pipeline.

(c) **Verification of material properties and attributes.** If an operator does not have traceable, verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities; Anomaly direct examinations, in situ evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

(1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined in a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.

(2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.

(3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.
(4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.

(5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.

(d) Special requirements for nondestructive Methods. Procedures developed in accordance with paragraph (c) of this section for verification of material properties and attributes using nondestructive methods must:

(1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage.

(2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and

(3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

(e) Sampling multiples segments of pipe. To verify material properties and attributes for a population of multiple, comparable segments of pipe without traceable, verifiable, and complete records, an operator may use a sampling program in accordance with the following requirements:

(1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of the defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.

(2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, in situ evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavations activities pursuant to § 192.614, until completion of the lesser of the following:

   (i) One excavation per mile rounded up to the nearest whole number; or (ii) 150 excavations if the population is more than 150 miles.

(3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).

(4) If the test results identify line pipe with properties that are not consistent with available information or existing expectations or assume properties used for operations and maintenance in the past, the operator must establish an expanded sampling program. The expanded sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an expanded sampling approach in accordance with § 192.18.

(5) An operator may use an alternative statistical sampling approach that differs from the requirements specified in paragraph (e)(2) of this section. The alternative sampling program must use valid statistical bases designed to achieve at least a 95% confidence level that material properties used in the operation and maintenance of the pipeline are valid. The approach must address how the sampling plan will be expanded to address findings that reveal material properties that are not consistent with all available information or existing expectations or assumed material properties.
properties used for pipeline operations and maintenance in the past. Operators must notify PHMSA in advance of using an alternative sampling approach in accordance with §192.18.

(f) Components. For mainline pipeline components other than line pipe, an operator must develop and implement procedures in accordance with paragraph (c) of this section for establishing and documenting the ANSI rating or pressure rating (in accordance with ASME/ANSI B16.5(incorporated by reference, see §192.7)).

(1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.

(2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:
   (i) Larger than 2 inches in nominal outside diameter,
   (ii) Material grades of 42,000 psi (Grade X-42) or greater, or
   (iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.

(3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

(g) Uprating. The material properties determined from the destructive or nondestructive tests required by this section cannot be used to raise the grade or specification of the material, unless the original grade or specification is unknown and MAOP is based on an assume yield strength of 24,000 pisi in accordance with §192.107(b)(2).

[Amtd. 192-125, Oct. 1, 2019]
§192.609
Change in class location: Required study.

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.

GUIDE MATERIAL

No guide material necessary.
(b) Instructions for working effectively with the local ICS should be described as follows.
   (1) When local emergency responders have set up an Incident Command prior to the arrival of
       operator personnel:
       (i) The first operator person to arrive should introduce himself to the Incident Commander
           as the representative from the gas pipeline operator, and
       (ii) That person remains the point of contact until the incident has been made safe or until
           relieved of that duty by another operator representative.
   (2) When local emergency responders are not yet on the scene:
       (i) The first person representing the operator to arrive will serve as Command, and
       (ii) That person should assess the situation and take, or direct, all necessary actions to
           protect people, protect property, and secure the flow of gas.
   (3) If local emergency responders arrive later and set up an ICS:
       (i) The Command for the gas pipeline operator should introduce himself as the point of
           contact for the operator, brief the local Incident Commander, and
       (ii) That person should remain the point of contact until the incident has been made safe or
           until relieved of that duty by another operator representative.

(c) Consider providing operator’s first-responder personnel with intrinsically safe communication
devices to carry with them while on duty. Be aware of communication blind spots.

1.3 Prompt and effective response to each type of emergency.
Various types of emergencies will require different responses in order to evaluate and mitigate the
hazard. Consideration should be given to the following.
(a) Emergencies involving gas detected in or near buildings should be prioritized in order to have
    sufficient operator personnel for response. For leak classification and action criteria, refer to Guide
    Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.
    See §192.605(b)(11), which requires procedures for prompt response to reports of a gas odor in or
    near buildings.
(b) Emergencies involving damage to buried facilities during excavation activities should be assessed
    for potential hidden and multiple leak locations.
(c) Emergencies involving fire located on or near pipeline facilities may require those facilities to be
    isolated. If a major delivery point is involved, an alternative gas supply may be needed.
(d) Emergencies involving an explosion on or near pipeline facilities may result in damage from fire and
    shock waves.
(e) Emergencies involving blowing or ignited gas may hinder local emergency responders’ search and
    rescue efforts.
(f) Natural disasters, such as earthquakes and other significant earth movement (e.g., landslides,
    mudslides, sinkholes), floods, hurricanes, tidal waves, tornadoes, or wildfires, might affect the safe
    operation of pipeline facilities in many different ways. Manmade disasters, such as mine
    subsidence, sabotage, infrastructure collapse, or corrosive chemical discharge, might also affect
    safe operations. Operators affected by these disasters should dispatch personnel to the areas as
    soon as practicable to evaluate the situation and proceed with emergency response related to their
    gas facilities, as necessary, to keep or make conditions safe. Operators of pipeline facilities affected
    by natural disasters should address these situations in the emergency procedures and consider
    preparing a disaster plan including site-specific procedures, if appropriate. The procedures and plan
    may include the items listed below.

   Note: Multiple advisory bulletins have been issued regarding the potential for damage to pipeline
   facilities caused by the passage of hurricanes and flooding. For examples, see OPS Advisory Bulletin
   ADB-2015-02 (80 FR 36042, June 23, 2015; see Guide Material Appendix G-192-1, Section 2) and
   the advisory bulletin referenced in 6 of the guide material under §192.613.
   (1) Information on responsibilities for operator personnel communication and work assignments.
   (2) Information on alternative reporting locations for operator personnel in case the primary location
       is damaged or inaccessible.
   (3) Procedures to assess damage and mitigate hazardous conditions, which may include the
       following.
(i) Establishing an operations and communications command center.
(ii) Establishing a field command post.
(iii) Determining personnel, material, and equipment requirements.
(iv) Deploying personnel to sites and locations where they can take appropriate actions, such as shutdown, isolation, or containment.
(v) Evaluating the accessibility of pipeline facilities that may be in jeopardy such as valves and regulator stations needed to isolate the system.
(vi) Performing frequent patrols to evaluate the effects on pipeline facilities.
(vii) Determining the extent of damage to pipeline facilities.
(viii) Ensuring line markers are still in place or replaced in a timely manner for operator-defined critical locations or facilities.
(ix) Determining if facilities that are normally above ground (e.g., valves, regulators, relief devices) have become submerged and are in danger of being struck by vessels or debris. Facilities in danger of being struck by vessels should be marked with an appropriate buoy if the locations can be reached safely.
(x) Performing surveys to determine the depth of cover over pipelines and the condition of any exposed pipelines, such as those crossing scour holes or where water channels have changed. For pipelines in the Gulf of Mexico and its inlets with waters less than 15 feet deep, see §192.612.
(xi) Evaluating right-of-way conditions at water crossings during the flooding and after waters subside by performing patrols, including appropriate overflights. Notify appropriate staff of any localized or systemic flooding to determine whether pipeline crossings may have been damaged or would be in imminent jeopardy from future flooding.

Note: After the emergency response, information about the presence of pipelines and the risks posed by reduced cover should be shared with the affected landowners and with contractors, highway departments, and others involved in restoration activities following the natural or manmade disaster. Agricultural agencies may help inform farmers of the potential hazard from reduced cover.

(4) Procedures to re-establish normal operations including service restoration and progress tracking and reporting. For large-scale outages of distribution systems, see Guide Material Appendix G-192-7.

(5) Other considerations.
(i) Maintaining mutual assistance agreements with other pipeline operators.
(ii) Providing accommodations for operator personnel and other assisting personnel.
(iii) Shutting off gas service to an affected area if evacuations of that area are being made by police or fire departments.

1.4 Assuring the availability of personnel, equipment, tools, and materials.
Arrangements made to assure the availability of personnel, equipment, tools, and materials that may be needed should be described in accordance with the type of emergency. These arrangements should include the assignment of responsibilities for coordinating, directing and performing emergency functions, including the following.
(a) Responsibility for overall coordination, which may be at the operator's area facilities or at the operating executive level, depending on the scope of the emergency.
(b) Responsibility for executing the operator's emergency operations, based on the scope of the emergency.
(c) Determination of departmental functions or services during an emergency, including determination of individual job assignments required to implement the plan.
(d) Determination of coordination required between departments, including provision for bypassing the normal chain of command as necessitated by the emergency.
(e) Determination of coordination required to implement mutual aid agreements.
(f) Responsibility for providing accurate information and cooperation with the news media.
(g) Establishment of an operator's first-responder checklist of tools and equipment, such as combustible
gas indicators (capable of detecting LEL), probe rods, radios, cones, grates, barricades, and manhole cover lifting devices. The list should be reviewed and updated as needed, and the operator should periodically verify that their first responders are properly equipped.

1.5 Controlling emergency situations.
Actions that may be initiated by the first employee arriving at the scene in order to protect people and property should be described. These actions may include the following.
(a) Determining the scope of the emergency.
(b) Evacuating and preventing access to premises that are or may be affected.
(c) Preventing accidental ignition.
(d) Reporting to the appropriate supervisor on the situation and requesting further instructions or assistance, if needed.

1.6 Emergency shutdown and pressure reduction.
(a) Provisions for shutdown or pressure reduction in the pipeline system as may be necessary to minimize hazards should be described. The plans should include the following.
(1) Circumstances under which available shutdown, pressure reduction, or system isolation methods are applicable. Considerations should include the following.
   (i) Access to, and operability of, valves located in areas prone to high water or flooding conditions.
   (ii) Proximity to buildings and other structures.
   (iii) Proximity to local emergency responders’ search and rescue area.
(2) Circumstances under which natural gas might be allowed to safely escape to the atmosphere (i.e., vent) until shutdown or repair.
   (i) Some possible reasons for using this alternative are as follows.
      (A) Curtailment will affect critical customers (e.g., hospitals).
      (B) Curtailment will affect large numbers of customers during adverse weather conditions.
      (C) Line break or leak is remotely located and does not cause a hazard to the public or property.
   (ii) Some factors to consider are as follows.
      (A) Sources of ignition.
      (B) Leak or damage location (rural vs. urban).
      (C) Proximity to buildings and other structures.
      (D) Local emergency responders’ ability to access the search and rescue area.
      (E) Ability to make and keep the area safe while gas vents.
      (F) Ability to coordinate with operator and local emergency responders and public officials.
(3) Lists or maps of valve locations, regulator locations, compressor schematics, and blowdown locations.
(4) Maps or other records to identify sections of the system that will be affected by the operation of each valve or other permanent shutdown device.
(5) Provision for positive identification of critical valves and other permanent facilities required for shutdown. See §192.605.
(6) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
(b) Distribution system plans should include consideration of the potential hazards associated with an outage and the need to minimize the extent of an outage, and to expedite service restoration. In addition to the use of any existing emergency valves within a distribution system, consideration should also be given to other methods of stopping gas flow, such as:
(1) Injecting viscous materials or polyurethane foam through drip risers or any other available connections to the main.
(2) Use of squeeze-off or bagging-off techniques.
1.7 Making safe any actual or potential hazard.
Provisions should be described for identifying, locating, and making safe any actual or potential hazard. These may include the following.
(a) Controlling pedestrian and vehicular traffic in the area.
(b) Eliminating potential sources of ignition.
(c) Controlling the flow of leaking gas and its migration. See Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.
(d) Ventilating affected premises.
(e) Venting the area of the leak by removing manhole covers, barholing, installing vent holes, or other means.
(f) Determining the full extent of the hazardous area, including the discovery of gas migration and secondary damage such as the following.
   (1) Deformation of a gas service line indicating that the service line might be separated underground near a foundation wall or at an inside meter set assembly.
   (2) Multiple underground leaks that may have occurred, allowing gas to migrate into adjacent buildings.
   (3) Potential pipe separation and gas release at unseen underground locations that may result in gas entering adjacent buildings, or following or entering other underground structures connected to buildings.
(g) Monitoring for a change in the extent of the hazardous area.
(h) Determining whether there are utilities whose proximity to the pipeline may affect the response.
   (1) Visually identify the presence of electric and other utilities surrounding the pipeline facility.
   (2) Evaluate the potential risk associated with the continued operation of the surrounding utilities.
   (3) Use the local ICS to contact the owner of the surrounding utilities, as necessary, to implement a more effective and coordinated emergency response.
(i) Coordinating the actions to be taken with fire, police, and other public officials, including the following.
   (1) Search and rescue efforts.
   (2) Ensuring information pertinent to emergency response is shared in a timely manner.

1.8 Restoration of service.
Planning for the safe restoration of service to all facilities affected by the emergency, after proper corrective measures have been taken, should include consideration of the following.
(a) Provisions for safe restoration of service should include the following.
   (1) Turn-off and turn-on of service to customers, including strict control of turn-off and turn-on orders to assure safety in operation.
   (2) Purging and repressurizing of pipeline facilities. For service lines containing an EFV, see guide material under §192.381 for purging considerations.
   (3) Resurvey of the area involved in a leak incident to locate any additional leaks.
(b) Execution of the repair and restoration of service functions will necessitate prior planning, such as the following.
   (1) Sectionalizing to reduce extent of outages and to expedite turn-on following a major outage.
   (2) Lists and maps for valve locations, regulator locations, and blowoff or purge locations.
   (3) Provisions for positive identification of valves and regulator facilities. See 2.2 of the guide material under §192.605.
   (4) Equipment checklist for repair crews.
   (5) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
   (6) Emergency supply connections with other gas companies and procedures for making use of such connections.
   (7) List of contractors, utilities, and municipalities that have agreed to provide equipment and workers to assist with repair and service restoration. Procedures for securing and utilizing this equipment and workforce should be described.
   (8) Prearranged use of facilities, owned by others, for temporary operating headquarters for repair and restoration activities. Arrangements should also be made for all necessary support
functions for such temporary operating headquarters.

(9) Cooperation with appropriate civil organizations in providing housing and feeding facilities for persons requiring shelter during an outage in severe weather.

(10) Arrangements to maintain service to critical customers, such as hospitals, to the degree possible during a general service curtailment or outage. In addition, a similar priority should be assigned for turn-off activities.

(c) For large-scale outages, also see Guide Material Appendix G-192-7.

1.9 Providing for investigation of failures.

Instructions for initiating investigation of failures in accordance with §192.617 should include the following, where applicable.

(a) Keeping a log of significant events and of actions taken.

(b) Preserving failed facilities or equipment for analysis, as may be appropriate.

(c) Obtaining and submitting information required by jurisdictional regulatory agencies.

(d) Including the requirement for post-accident/incident drug and alcohol testing. See Part 199 – Drug and Alcohol Testing and OPS Advisory Bulletin ADB-12-02 (77 FR 10666, Feb. 23, 2012; see Guide Material Appendix G-192-1, Section 2).

1.10 Incident Command System (ICS).

(a) In the context of applying the ICS, the Federal Emergency Management Agency (FEMA) has defined the term incident as "an occurrence, either caused by humans or natural phenomena, that requires response actions to prevent or minimize loss of life or damage to property and/or the environment." Certain gas emergencies could fall within the FEMA definition of an incident. Examples of FEMA incidents include the following.

(1) Fire, both structural and wildland.

(2) Natural disasters, such as tornadoes, floods, ice storms, or earthquakes.

(3) Human and animal disease outbreaks.

(4) Search and rescue missions.

(5) Hazardous materials incidents.

(6) Criminal acts and crime scene investigations.

(7) Terrorist incidents, including the use of weapons of mass destruction.

(8) National Special Security Events, which are designated by the U.S. Department of Homeland Security (e.g., Presidential inaugurations, national political conventions, Super Bowls).

(9) Other planned events, such as parades or demonstrations.

(b) The ICS is a management system for dealing with emergencies. It has been developed from reviewing past emergencies and formalized into a structured system by FEMA and other emergency response agencies. It is a consistently applied system for controlling on-site personnel, facilities, equipment, and communications in an emergency. It is a designated system used from the time a FEMA incident occurs until the requirements for implementing the ICS no longer exist.

(c) When an operator and local emergency responders implement an ICS, respective plans may differ but should be based on similar principles so the plans are compatible. The ICS may be used for small or large incidents, remaining adequately flexible to adjust to the changing needs of an incident.

(d) The ICS functions typically include the following.

(1) Safety – public and employees.

(2) Security – utilize operator or local public safety personnel.

(3) Commander responsibilities – establish command center, transfer of command.

(4) Operational – incident stabilization plan, repair plan.

(5) Logistics – material, equipment, other resources.

(6) Public relations – communications, notifications, information liaison.

(7) Personnel management.

(e) The ICS supports responders and decision makers by providing the data they need through effective information and intelligence management. The data provided may include information on the following.
(1) Maps and records for critical infrastructure and other facilities.
(2) Load studies.
(3) Affected customers, including residential, commercial, and industrial customers.
(f) Additional information on the ICS can be found at: training.fema.gov/emiweb/is/icsresource/

1.11 Role of control room during an emergency.
If applicable, an operator should provide controllers with procedures and tools when controllers are required to respond to an emergency in accordance with §192.631.

2 ACQUAINT APPROPRIATE OPERATING AND MAINTENANCE EMPLOYEES WITH THE PROCEDURES (§192.615(b))

Each operator should have a program to assure that all operating and maintenance personnel who may be required to respond to an emergency are acquainted with the requirements of the written emergency procedures. The program should include the following.

2.1 Provide employees access to emergency procedures manual.
The latest edition of the written emergency procedures and plans should be easily accessible so that employees may become familiar with them. Consideration should be given to placing a copy near telephones and base radio units that might be used to notify the operating personnel of an emergency.

2.2 Training of employees.
Appropriate operating and maintenance employees should be trained to ensure that they are knowledgeable of the requirements of the written emergency procedures. Persons providing training of the emergency procedures should be knowledgeable in emergency response and training techniques. Consideration should be given to conducting classroom or field simulated emergency exercises involving appropriate personnel, such as operating, maintenance, and dispatch personnel, including those monitoring and controlling operations of remote facilities. Emergency exercises should include worst-case scenarios. The effectiveness of the training may be verified by methods such as oral test, written test, or evaluating performance during simulated emergencies. Such verification of the effectiveness of training should be documented.

Those responsible for instruction of operator employees should place special emphasis on the following.
(a) Understanding the properties and behavior of the gas, as related to types of potential hazards, including the recognition of, and the appropriate actions to take regarding, hazardous leaks.
(b) Coordinated execution of the operator's written emergency procedures, including coordination among different functional groups (e.g., between gas control and operator emergency response personnel in an emergency situation).
(c) Knowledge of how emergency control is exercised in various sections of the system, including identification and operation of key valves.
(d) Ability to use operator's maps or other facility records.
(e) Responsibilities of each employee responding to an emergency and the relationship to the emergency procedure. This should include responsibilities related to interacting effectively with local emergency responders in an Incident Command System.
(f) Evaluation of reports of gas odor and other potential emergencies.
(g) Response to different types of emergency situations, such as gas escaping inside or outside and gas burning inside or outside. Appropriate actions should include avoiding the use of doorbells or buzzers when responding to possible leaks, evacuation, elimination of ignition sources, gas shutoff, ventilation, and other precautionary measures.
cutting and outside forces due to tools and equipment).

(d) Procedures may be necessary for proper sampling and handling of soil and groundwater specimens where corrosion may be involved.

(e) Procedures controlling the cutting, cleaning, lifting, identifying, and shipping of pipe specimens should be considered for preservation of valuable evidence on the pipe surface, and on any tear surface or fracture face, including making cuts far enough from the failure to avoid damaging critical areas of the specimen.

(f) The number of specimens needed to be collected at the failure site may vary depending on the type and number of tests anticipated. A series of independent or destructive tests may require multiple specimens. If there is a need to confirm the pipe material specifications, then additional pipe specimens should be obtained near the failure, but in an area of the piping where the physical properties and characteristics are unaffected by the failure itself. Other investigatory procedures may be utilized to confirm pipe material specifications.

8 TESTING AND ANALYSIS

(a) Recognized standard destructive and nondestructive techniques are the preferred means to examine test specimens. The testing methods used should be suited to the particular material being tested, and be pertinent to the failure investigation.

(b) Analysis and data on failures should be compiled and reviewed.

(c) The need for continuing surveillance of pipeline facilities should be determined. See guide material under §192.613.

9 REFERENCE

(a) NFPA 921, "Guide for Fire and Explosion Investigations."

§192.619

Maximum allowable operating pressure: Steel or plastic pipelines.

[Effective Date: 07/01/2020]

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or 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 uprated 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 of Appendix N of ASME B31.8 (incorporated by reference, see §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

2 The pressure obtained by dividing the pressure to which the pipeline 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 Table 1 to paragraph (a)(2)(ii):
### TABLE 1 TO PARAGRAPH (a)(2)(ii)

<table>
<thead>
<tr>
<th>Class location</th>
<th>Installed before (Nov. 12 1970)</th>
<th>Installed after (Nov. 11, 1970) and before July 1, 2020</th>
<th>Installed on or after July 1, 2020</th>
<th>Converted under § 192.14</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 ..................</td>
<td>1.1</td>
<td>1.1</td>
<td>1.25</td>
<td>1.25</td>
</tr>
<tr>
<td>2 ..................</td>
<td>1.25</td>
<td>1.25</td>
<td>1.25</td>
<td>1.25</td>
</tr>
<tr>
<td>3 ..................</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>4 ..................</td>
<td>1.4</td>
<td>1.5</td>
<td>1.5</td>
<td>1.5</td>
</tr>
</tbody>
</table>

1For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated 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 the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

<table>
<thead>
<tr>
<th>Pipeline segment</th>
<th>Pressure date</th>
<th>Test date</th>
</tr>
</thead>
<tbody>
<tr>
<td>— Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006.</td>
<td>March 15, 2006, or date line becomes subject to this part, whichever is later.</td>
<td>5 years preceding applicable date in second column.</td>
</tr>
<tr>
<td>— Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and 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) The requirements on pressure restrictions in this section do not apply in the following instance. 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 the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

(e) Notwithstanding the requirements in paragraphs (a) through (d) of this section, operators of onshore steel transmission pipelines that meet the criteria specified in § 192.624(a) must establish and document the maximum allowable operating pressure in accordance with § 192.624.

(f) Operators of onshore steel transmission pipelines must make and retain records necessary
to establish and document the MAOP of each pipeline segment in accordance with paragraphs (a) through (e) of this section as follows:

(1) Operators of pipelines in operation as of July 1, 2020 must retain any existing records establishing MAOP for the life of the pipeline;

(2) Operators of pipelines in operation as of July 1, 2020 that do not have records establishing MAOP and are required to reconfirm MAOP in accordance with §192.624, must retain the records reconfirming MAOP for the life of the pipeline; and

(3) Operators of pipelines placed in operation after July 1, 2020 must make and retain records establishing MAOP for the life of the pipeline.


GUIDE MATERIAL

This guide material is under review following Amendment 192-125.

(a) Before adjusting the operation of a pipeline by increasing pressure within the limits of the pipeline segment's MAOP, but substantially above a historical long-term operating pressure, the operator should consider a review of the operating, maintenance, and testing history for the segment. See guide material under §§192.555 and 192.557. Pressure should be increased gradually at an incremental rate. The operator should consider conducting a leak survey when the pressure increase is concluded.


§192.620

Alternative maximum allowable operating pressure for certain steel pipelines. [Effective Date: 10/01/15]

(a) How does an operator calculate the alternative maximum allowable operating pressure? An operator calculates the alternative maximum allowable operating pressure by using different factors in the same formulas used for calculating maximum allowable operating pressure under §192.619(a) as follows:

(1) In determining the alternative design pressure under §192.105, use a design factor determined in accordance with §192.111(b), (c), or (d) or, if none of these paragraphs apply, in accordance with the following table:

<table>
<thead>
<tr>
<th>Class Location</th>
<th>Alternative Design Factor (F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.80</td>
</tr>
<tr>
<td>2</td>
<td>0.67</td>
</tr>
<tr>
<td>3</td>
<td>0.56</td>
</tr>
</tbody>
</table>

(i) For facilities installed prior to December 22, 2008, for which §192.111(b), (c), or (d)
applies, use the following design factors as alternatives for the factors specified in those paragraphs: §192.111(b) — 0.67 or less; 192.111(c) and (d) — 0.56 or less.

(ii) [Reserved]

(2) The alternative maximum allowable operating pressure is the lower of the following:
   (i) The design pressure of the weakest element in the pipeline segment, determined under subparts C and D of this part.
   (ii) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction by a factor determined in the following table:

<table>
<thead>
<tr>
<th>Class Location</th>
<th>Alternative Test Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1.25</td>
</tr>
<tr>
<td>2</td>
<td>1.50</td>
</tr>
<tr>
<td>3</td>
<td>1.50</td>
</tr>
</tbody>
</table>

1For Class 2 alternative maximum allowable operating pressure segments installed prior to December 22, 2008 the alternative test factor is 1.25.

(b) When may an operator use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section? An operator may use an alternative maximum allowable operating pressure calculated under paragraph (a) of this section if the following conditions are met:

(1) The pipeline segment is in a Class 1, 2, or 3 location;
(2) The pipeline segment is constructed of steel pipe meeting the additional design requirements in §192.112;
(3) A supervisory control and data acquisition system provides remote monitoring and control of the pipeline segment. The control provided must include monitoring of pressures and flows, monitoring compressor start-ups and shut-downs, and remote closure of valves per paragraph (d)(3) of this section;
(4) The pipeline segment meets the additional construction requirements described in §192.328;
(5) The pipeline segment does not contain any mechanical couplings used in place of girth welds;
(6) If a pipeline segment has been previously operated, the segment has not experienced any failure during normal operations indicative of a systemic fault in material as determined by a root cause analysis, including metallurgical examination of the failed pipe. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operation at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and
(7) At least 95 percent of girth welds on a segment that was constructed prior to December 22, 2008, must have been non-destructively examined in accordance with §192.243(b) and (c).

(c) What is an operator electing to use the alternative maximum allowable operating pressure required to do? If an operator elects to use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section for a pipeline segment, the operator must do each of the following:

(1) For pipelines already in service, notify the PHMSA pipeline safety regional office where the pipeline is in service of the intention to use the alternative pressure at least 180 days before operating at the alternative MAOP. For new pipelines, notify the PHMSA pipeline safety regional office of planned alternative MAOP design and operation at least 60 days prior to the earliest start date of either pipe manufacturing or construction activities. An operator must also notify the state pipeline
§192.620

safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement or where an intrastate pipeline is regulated by that state.

(2) Certify, by signature of a senior executive officer of the company, as follows:
   (i) The pipeline segment meets the conditions described in paragraph (b) of this section; and
   (ii) The operating and maintenance procedures include the additional operating and maintenance requirements of paragraph (d) of this section; and
   (iii) The review and any needed program upgrade of the damage prevention program required by paragraph (d)(4)(v) of this section has been completed.

(3) Send a copy of the certification required by paragraph (c)(2) of this section to each PHMSA pipeline safety regional office where the pipeline is in service 30 days prior to operating at the alternative MAOP. An operator must also send a copy to a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

(4) For each pipeline segment, do one of the following:
   (i) Perform a strength test as described in §192.505 at a test pressure calculated under paragraph (a) of this section or
   (ii) For a pipeline segment in existence prior to December 22, 2008, certify, under paragraph (c)(2) of this section, that the strength test performed under §192.505 was conducted at test pressure calculated under paragraph (a) of this section, or conduct a new strength test in accordance with paragraph (c)(4)(i) of this section.

(5) Comply with the additional operation and maintenance requirements described in paragraph (d) of this section.

(6) If the performance of a construction task associated with implementing alternative MAOP that occurs after December 22, 2008, can affect the integrity of the pipeline segment, treat that task as a "covered task", notwithstanding the definition in §192.801(b) and implement the requirements of subpart N as appropriate.

(7) Maintain, for the useful life of the pipeline, records demonstrating compliance with paragraphs (b), (c)(6), and (d) of this section.

(8) A Class 1 and Class 2 location can be upgraded one class due to class changes per §192.611(a). All class location changes from Class 1 to Class 2 and from Class 2 to Class 3 must have all anomalies evaluated and remediated per: The "original pipe line class grade" §192.620(d)(11) anomaly repair requirements; and all anomalies with a wall loss equal to or greater than 40 percent must be excavated and remediated. Pipelines in Class 4 may not operate at an alternative MAOP.

(d) What additional operation and maintenance requirements apply to operation at the alternative maximum allowable operating pressure? In addition to compliance with other applicable safety standards in this part, if an operator establishes a maximum allowable operating pressure for a pipeline segment under paragraph (a) of this section, an operator must comply with the additional operation and maintenance requirements as follows:
To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:

<table>
<thead>
<tr>
<th>Step</th>
<th>Description</th>
</tr>
</thead>
</table>
| (1) Identifying and evaluating threats | Develop a threat matrix consistent with §192.917 to do the following:  
(i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and  
(ii) Describe and implement procedures used to mitigate the risk. |
| (2) Notifying the public | (i) Recalculate the potential impact circle as defined in §192.903 to reflect use of the alternative maximum operating pressure calculated under paragraph (a) of this section and pipeline operating conditions; and  
(ii) In implementing the public education program required under §192.616, perform the following:  
(A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and  
(B) Include information about the integrity management activities performed under this section within the message provided to the audience. |
| (3) Responding to an emergency in an area defined as a high consequence area in §192.903 | (i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (d)(2)(i) of this section.  
(ii) If personnel response time to mainline valves on either side of the high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control.  
(iii) Remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream.  
(iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control. |
§192.623
Maximum and minimum allowable operating pressure: Low-pressure distribution systems.

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

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


GUIDE MATERIAL

(a) Each existing low-pressure distribution system, connected to a gas source where the failure of pressure control might result in a pressure which would exceed the maximum allowable operating pressure of the system, should be equipped with suitable pressure relieving or pressure limiting devices which will control the pressure to the maximum allowable operating pressure of the system.

(b) For low-pressure distribution systems containing steel or plastic pipelines, see §192.619.

§192.624
Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

(a) Applicability. Operators of onshore steel transmission pipeline segments must reconfirm the maximum allowable operating pressure (MAOP) of all pipeline segments in accordance with the requirements of this section if either of the following conditions are met:

(1) Records necessary to establish the MAOP in accordance with § 192.619(a), including records required by § 192.517(a), are not traceable, verifiable, and complete and the pipeline is located in one of the following locations:

(i) A high consequence area as defined in § 192.903; or

(ii) A Class 3 or Class 4 location.

(2) The pipeline segment’s MAOP was established in accordance with § 192.619(c), the pipeline segment’s MAOP is greater than or equal to 30 percent of the specified minimum yield strength and the pipeline is located in the following areas:

(i) A high consequence area as defined in § 192.903; or

(ii) A Class 3 or Class 4 location; or

(iii) A moderate consequence area as defined by § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inspection inline tools.

(b) Procedures and completion dates. Operators of a pipeline subject to this section must develop and document procedures for completing all actions required by this section by July 1, 2021. These procedures must include a process for reconfirming MAOP for any pipelines that meet the condition of § 192.624(a), and for performing a spike test or material verification in accordance with §§ 192.506 and 192.607, if applicable. All actions required by this section must be completed according to the following schedule:
(1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.

(2) Operators must complete all actions required by this section on at least 100% of the pipeline mileage by July 2, 2035 or as soon as practicable, but not to exceed 4 years after the pipeline segment first meets the condition of § 192.624(a) (e.g., due to a location becoming a high consequence area) whichever is later.

(3) If operational and environmental constraints limit an operator from meeting the deadline in § 192.624, the operator may petition for an extension of the completion deadlines for up to 1 year, upon submittal of notification in accordance with § 192.18. The notification must include an up to date plan for completing all actions in accordance with this section, the reason for the requested extension, current status, proposed completion date, outstanding remediation activities, and any needed temporary measures needed to mitigate the impact on safety.

(c) **Maximum allowable operating pressure determination.** Operators of a pipeline segment meeting a condition in paragraph (a) of this section must reconfirm its MAOP using one of the following methods:

(1) **Method 1: Pressure test.** Perform a pressure test and verify material property records in accordance with § 192.607 and the following requirements:
   (i) Pressure test. Perform a pressure test in accordance of subpart J of this part. The MAOP must equal to the test pressure divided by the greater of either 1.25 or applicable class location factor in § 192.619(a)(2)(ii).
   (ii) Material properties records. Determine if the following material properties records are documented in traceable, verifiable, and complete records. Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).
   (iii) Material properties verification. If any of the records required by paragraph (c)(1)(ii) are not documented in traceable, verifiable, and complete records the operator must obtain the missing records in accordance with § 192.607. The operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during a pressure test, the operator test any removed pipe from the pressure test failure in accordance with § 192.607.

(2) **Method 2: Pressure Reduction.** Reduce pressure as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative of 8 hours during a continuous 30-day period. The value used at the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (i.e., the location specific operating pressure at each location).
   (i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:
     [A] For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the MAOP to no greater than the highest actual operating pressure sustained during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to  Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4
     [B] For pipeline segments where a class location changed from Class 1 to Class 3, reduce the MAOP to no greater than the highest actual operating pressure sustained during the 5 years preceding October 1, 2019, divided by 2.00.
(ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is establish using Method 2.

(iii) If an operator elects to use Method 2, but desires to use a less conservative pressure reduction factor or longer look-back period, the operator must notify PHMSA in accordance with § 192.18 no later than 7 calendar days after establishing the reduced MAOP. The notification must include the following details:

(A) Descriptions of the operational constraint, special circumstances, or other factors that preclude or make it impracticable, to use the pressure reduction factor specified in § 192.624(c)(2);

(B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 192.712;

(C) Justification that establishing MAOP by another method allowed by this section is impracticable;

(D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material property records, material properties verified in accordance with § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and

(E) Planned duration for operating the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressure and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.


(4) Method 4: Pipe Replacement. Replace the pipeline segment in accordance with this part.

(5) Method 5: Pressure Reduction for Pipeline Segments with Small Potential Impact Radius. Pipelines with a potential impact radius (PIR) less than equal to 150 feet may establish the MAOP as follows:

(i) Reduce the MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.1. The highest actual sustained pressure must have been reached for minimum cumulative duration of 8 hours during one continuous 30-day period. The reduced MAOP pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (i.e., the location specific operating pressure at each location).

(ii) Conduct patrols in accordance with § 192.705 paragraphs (a) and (c) and conduct instrumented leakage surveys in accordance with § 192.706 at intervals no exceed those in the following table 1 to § 192.624(c)(5)(ii):

<table>
<thead>
<tr>
<th>Class locations</th>
<th>Patrols</th>
<th>Leakage surveys</th>
</tr>
</thead>
<tbody>
<tr>
<td>(A) Class 1 and Class 2</td>
<td>3 1/2 months, but at least four times each calendar year.</td>
<td>3 1/2 months, but at least four times each calendar year.</td>
</tr>
<tr>
<td>(B) Class 3 and Class 4</td>
<td>3 months, but at least six times each calendar year.</td>
<td>3 months, but at least six times each calendar year.</td>
</tr>
</tbody>
</table>

(iii) Under Method 5, future uprating of the pipeline segment in accordance with subpart K is allowed.

Addendum 5, December 2019

330 (a)
(6) Method 6: Alternative Technology. Operators may use alternative technical evaluation process that provides a documented engineering analysis for establishing MAOP. If an operator elects to use alternative technology, the operator must notify PHMSA in advance in accordance with § 192.18. The notice must include descriptions of the following details:

(i) The technology or technologies to be used for tests, examinations, and assessments; the method for establishing material properties; and analytical techniques with similar analysis from prior tool runs done to ensure the results are consistent with the required corresponding hydrostatic test pressure for the pipeline segment being evaluated.

(ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects and flaws, and remediate defects discovered;

(iii) Pipeline segment data, including original design, maintenance and operating history, anomaly or flaw characterization;

(iv) Assessment techniques and acceptance criteria, including anomaly detection confidence level, probability of detection, and uncertainty of the predicted failure pressure quantified as a fraction of specified minimum yield strength;

(v) If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with paragraph § 192.712.

(vi) Operational monitoring procedures

(vii) Methodology and criteria used to justify and establish the MAOP; and

(viii) Documentation of the operator’s process and procedures used to implement the use of the alternative technology, including any records generated through its use.

[Amnd. 192-125, Oct 1, 2019]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125.

§192.625

Odorization of gas.

[Effective Date: 10/15/03]
(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.


GUIDE MATERIAL

1 LATERAL LINE DEFINITION (§192.625(b)(3))

   Lateral line (transmission) is a pipeline that branches from the main line or trunk of the transmission system, as determined by the operator, for the purpose of transporting gas to one or more distribution centers or to one or more large volume customers.

2 PERIODIC SAMPLING (§192.625(f))

2.1 Sites.
   (a) Sampling sites should be selected to ensure that all gas within the piping system contains the required odorant concentration. The number of sites selected depends upon the size and configuration of the system, location of gate stations and locations suspected of low odorant level within the system.
   (b) Consider the need for additional sampling sites when portable compressed natural gas (CNG) is temporarily introduced into the pipeline system. The type of processes used to produce CNG may cause the odorant level in the CNG to be reduced.

2.2 Frequency.
   The testing should be performed at sufficiently frequent intervals to ensure that the gas is odorized to the required level.
2.3 Tests.
   (a) Odor concentration tests should be conducted by personnel having a normal sense of smell and trained in the operation and use of odor concentration meters and procedures. A reference for determining odor intensity of natural gas is ASTM D6273.
   (b) Sniff tests are qualitative tests that should be performed by individuals with a normal sense of smell. Such tests should be conducted by releasing small amounts of gas for a short duration in a controlled manner to determine whether odorant is detectable.
   (c) A normal sense of smell may be affected by smoking, eating spicy foods, chewing tobacco or gum, or the presence of other strong odors. It may also be affected by health-related conditions, such as a head cold, that may interfere with the sense of smell. Prolonged or repetitive exposure to gas should be avoided because the sense of smell will fatigue with extended exposure to odorant.
   (d) A program should be considered to periodically check personnel who perform odorant sampling to verify that they possess normal olfactory senses.
   (e) A chemical analysis instrument (e.g., gas chromatograph) may be used to support or supplement odorant level information. If a chemical analysis instrument is used, the operator should periodically validate the measured odorant concentration with the proper concentration, which must be determined separately in accordance with paragraph (a) above.

2.4 Records.
   (a) The operator should retain records of the odor level and odorant concentration test results.
   (b) Operators of master meter systems who do not perform odorant level testing should retain their own records of sniff testing and records received from gas suppliers.
   (c) Records of sniff testing should include the name of the person conducting the test, the date and location of the test, and whether odorant was detected.

3 ODOR INTENSITY IN PIPELINES
   (a) New or replaced pipeline systems can react with or adsorb odorant, which could reduce the odor intensity. A method to minimize this effect is to temporarily increase odorant injection rates until the odor intensity reaches the desired level.
   (b) Operators may consider informing plumbers and construction trades about odor reduction (see guide material under §192.629).

4 ODORANTS IN PLASTIC PIPELINES
   Odorants should be introduced into plastic pipelines only in the vapor state, unless it has been determined by investigation or test that the kind of plastic is adequately resistant to direct contact with the liquid odorant.

5 REFERENCES
   (a) AGA XQ0005, "Odorization Manual."
   (b) ASTM D6273, "Standard Test Methods for Natural Gas Odor Intensity."
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§192.627
Tapping pipelines under pressure.

[Effective Date: 11/12/70]

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

GUIDE MATERIAL

1 PERSONNEL QUALIFICATIONS

(a) Personnel performing hot taps should be:
   (1) Familiar with the pressure limitations of the hot tapping equipment to be used; and
   (2) Thoroughly trained in the mechanical procedures and safety precautions associated with the use of such equipment.

(b) Operators should consider using their Operator Qualification Program to establish tapping qualification criteria and documentation requirements for an individual's qualification.

2 IDENTIFICATION OF PIPE

The operator should accurately identify the line to be tapped. Special caution should be exercised when other underground facilities are known or suspected to be in the area. Special caution should also be exercised when personnel locating the line to be tapped are unfamiliar with the area. The operator's personnel should be familiar with the piping materials used by other utilities in the area, such as steel, plastic, and cast iron.

2.1 Before tapping.

(a) Maps and records. The operator should thoroughly review applicable maps and records and contact the operators of other underground facilities (e.g., one-call system) to determine the location of other lines that may be in the vicinity of the pipeline to be tapped.

(b) Exposed pipe. The following factors may be used to ensure that the exposed pipe is the one to be tapped. When identification of the pipe is uncertain, the operator should consider extending the excavation.
   (1) Outside diameter.
   (2) Longitudinal weld characteristics.
      (i) Electric resistance weld.
      (ii) Electric flash weld.
      (iii) Electric fusion/submerged arc weld.
      (iv) Spiral weld.
      (v) Seamless.
      (vi) Other weld characteristics.
   (3) Coating.
      (i) Coal tar.
      (ii) Asphalt.
      (iii) Wax.
      (iv) Thin-film.
      (v) Tape.
      (vi) Extruded mastic or similar material.
      (vii) Other coating materials.
      (viii) Bare.
§192.632

[Effective Date: 06/01/2020]

When an operator conducts an MAOP reconfirmation in accordance with § 192.624(c)(3) “Method 3” using an ECA to establish the material strength and MAOP of the pipeline segment, the ECA must comply with the requirements of this section. The ECA must assess: threats; loadings and operational circumstances relevant to those threats, including along the pipeline right-of-way; outcomes of the threat assessment; relevant mechanical and fracture properties; in-service degradation or failure processes; and initial and final defect size relevance. The ECA must quantify the interacting effects of threats on any defect in the pipeline.

(a) ECA Analysis.

(1) The material properties required to perform an ECA analysis in accordance with this paragraph are as follows: diameter, wall thickness, seam type, grade (minimum yield strength and ultimate tensile strength), and Charpy v-notch toughness values based upon the lowest operational temperatures, if applicable. If any material properties required to perform an ECA for any pipeline segment in accordance with this paragraph are not documented in traceable, verifiable and complete records, an operator must use conservative assumptions and include the pipeline segment in its program to verify the undocumented information in accordance with § 192.607. The ECA must integrate, analyze, and account for the material properties, the results of all tests, direct examinations, destructive tests, and assessments performed in accordance with this section, along with other pertinent information related to pipeline integrity, including close interval surveys, coating surveys, interference surveys required by subpart I of this part, cause analyses of prior incidents, prior pressure test leaks and failures, other leaks, pipe inspections, and prior integrity assessments, including those required by §§ 192.617, 192.710, and subpart O of this part.

(2) The ECA must analyze and determine the predicted failure pressure for the defect being assessed using procedures that implement the appropriate failure criteria and justification as follows:

(i) The ECA must analyze any cracks or crack-like defects remaining in the pipe, or that could remain in the pipe, to determine the predicted failure pressure of each defect in accordance with § 192.712.

(ii) The ECA must analyze any metal loss defects not associated with a dent, including corrosion, gouges, scrapes or other metal loss defects that could remain in the pipe, to determine the predicted failure pressure. ASME/ANSI B31G (incorporated by reference, see § 192.7) or R-STRENGTH (incorporated by reference, see § 192.7) must be used for corrosion defects. Both procedures and their analysis apply to corroded regions that do not penetrate the pipe wall over 80 percent of the wall thickness and are subject to the limitations prescribed in the equations’ procedures. The ECA must use conservative assumptions for metal loss dimensions (length, width, and depth).

(iii) When determining the predicted failure pressure for gouges, scrapes, selective seam weld corrosion, crack-related defects, or any defect within a dent, appropriate failure criteria and justification of the criteria must be used and documented.

(iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.
(3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

(4) The MAOP must be established at the lowest predicted failure pressure for any known or postulated defect, or interacting defects, remaining in the pipe divided by the greater of 1.25 or the applicable factor listed in §§ 192.619(a)(2)(ii).

(b) Assessment to determine defects remaining in the pipe. An operator must utilize previous pressure tests or develop and implement an assessment program to determine the size of defects remaining in the pipe to be analyzed in accordance with paragraph (a) of this section.

(1) An operator may use a previous pressure test that complied with subpart J to determine the defects remaining in the pipe if records for a pressure test meeting the requirements of subpart J of this part exist for the pipeline segment. The operator must calculate the largest defect that could have survived the pressure test. The operator must predict how much the defects have grown since the date of the pressure test in accordance with § 192.712. The ECA must analyze the predicted size of the largest defect that could have survived the pressure test that could remain in the pipe at the time the ECA is performed. The operator must calculate the remaining life of the most severe defects that could have survived the pressure test and establish a re-assessment interval in accordance with the methodology in § 192.712.

(2) Operators may use an inline inspection program in accordance with paragraph (c) of this section.

(3) Operators may use “other technology” if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use “other technology” in the ECA, it must notify PHMSA in advance of using the other technology in accordance with § 192.18. The “other technology” notification must have:
   (i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and
   (ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.

(c) In-line inspection. An inline inspection (ILI) program to determine the defects remaining in the pipe for the ECA analysis must be performed using tools that can detect wall loss, deformation from dents, wrinkle bends, ovalities, expansion, seam defects, including cracking and selective seam weld corrosion, longitudinal, circumferential and girth weld cracks, hard spot cracking, and stress corrosion cracking.

(1) If a pipeline has segments that might be susceptible to hard spots based on assessment, leak, failure, manufacturing vintage history, or other information, then the ILI program must include a tool that can detect hard spots.

(2) If the pipeline has had a reportable incident, as defined in § 191.3, attributed to a girth weld failure since its most recent pressure test, then the ILI program must include a tool that can detect girth weld defects unless the ECA analysis performed in accordance with this section includes an engineering evaluation program to analyze and account for the susceptibility of girth weld failure due to lateral stresses.

(3) Inline inspection must be performed in accordance with § 192.493.

(4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional infield examinations, reanalyze ILI data, or both.
(5) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.

(6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.

(d) **Defect remaining life.** If any pipeline segment contains cracking or may be susceptible to cracking or crack-like defects found through or identified by assessments, leaks, failures, manufacturing vintage histories, or any other available information about the pipeline, the operator must estimate the remaining life of the pipeline in accordance with § 192.712.

(e) **Records.** An operator must retain records of investigations, tests, analyses, assessments, repairs, replacements, alterations, and other actions taken in accordance with the requirements of this section for the life of the pipeline.

[Issued by Amdt. 192-125, Oct. 1, 2019]

**GUIDE MATERIAL**

*This guide material is under review following Amendment 192-125.*
§192.710
Transmission lines: Assessments outside of high consequence areas.

(a) Applicability: This section applies to onshore steel transmission pipeline segments with a maximum allowable operating pressure of greater than or equal to 30% of the specified minimum yield strength and are located in:

(1) A Class 3 or Class 4 location; or

(2) A moderate consequence area as defined in § 192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (i.e., “smart pig”).

(3) This section does not apply to a pipeline segment located in a high consequence area as defined in § 192.903.

(b) General. (1) Initial assessment. An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of § 192.710(a) (e.g., due to a change in class location or the area becomes a moderate consequence area), whichever is later.

(2) Periodic reassessment. An operator must perform periodic reassessments at least once every 10 years, with intervals not to exceed 126 months, or a shorter reassessment interval based upon the type of anomaly, operational, material, and environmental conditions found on the pipeline segment, or as necessary to ensure public safety.

(3) Prior assessment. An operator may use a prior assessment conducted before July 1, 2020 as an initial assessment for the pipeline segment, if the assessment met the subpart O requirements of part 192 for in-line inspection at the time of the assessment. If an operator uses this prior assessment as its initial assessment, the operator must reassess the pipeline segment according to the reassessment interval specified in paragraph (b)(2) of this section calculated from the date of the prior assessment.

(4) MAOP verification. An integrity assessment conducted in accordance with the requirements of § 192.624(c) for establishing MAOP may be used as an initial assessment or reassessment under this section.

(c) Assessment method. The initial assessments and the reassessments required by paragraph (b) of this section must be capable of identifying anomalies and defects associated with each of the threats to which the pipeline segment is susceptible and must be performed using one or more of the following methods:

(1) Internal inspection. Internal inspection tool or tools capable of detecting those threats to which the pipeline is susceptible, such as corrosion, deformation and mechanical damage (e.g., dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with § 192.493;

(2) Pressure test. Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion, external corrosion, and other environmentally assisted corrosion mechanisms; manufacturing and related defect threats, including defective pipe and pipe seams; and stress corrosion cracking, selective seam weld corrosion, dents and other forms of mechanical damage;

(3) Spike hydrostatic pressure test. A spike hydrostatic pressure test conducted in accordance with § 192.506. A spike hydrostatic pressure test is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;
(4) **Direct examination.** Excavation and *in situ* direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all applicable threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), Inverse Wave Field Extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) **Guided Wave Ultrasonic Testing.** Guided Wave Ultrasonic Testing (GWUT) as described in Appendix F;

(6) **Direct assessment.** Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in § 192.923 and with the applicable requirements specified in §§ 192.925, 192.927 and 192.929; or

(7) **Other technology.** Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18.

(d) **Data analysis.** An operator must analyze and account for the data obtained from an assessment performed under paragraph (c) of this section to determine if a condition could adversely affect the safe operation of the pipeline using personnel qualified by knowledge, training, and experience. In addition, when analyzing inline inspection data, an operator must account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

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

(f) **Remediation.** An operator must comply with the requirements in §§ 192.485, 192.711, and 192.713, where applicable, if a condition that could adversely affect the safe operation of a pipeline is discovered.

(g) **Analysis of information.** An operator must analyze and account for all available relevant information about a pipeline in complying with the requirements in paragraphs (a) through (f) of this section.

[Amtd. 192-125, Oct. 01, 2019]

**GUIDE MATERIAL**

This guide material is under review following Amendment 192-125.

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§192.711

**Transmission lines: General requirements for repair procedures.**

[Effective Date: 10/01/10]

(a) **Temporary repairs.** Each operator must take immediate temporary measures to protect the public whenever:

(1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of
steel transmission line 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.

(b) **Permanent repairs.** An operator must make permanent repairs on its pipeline system according to the following:
(1) Non integrity management repairs: The operator must make permanent repairs as soon as feasible.
(2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O–Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by §192.933(d).

(c) **Welded patch.** Except as provided in §192.717(b)(3), no operator may use a welded patch as a means of repair.


GUIDE MATERIAL

(a) Prior to permanent mechanical or welded repair of a steel pipeline operating at greater than 20% SMYS, the operator should determine the thickness and integrity of the pipe wall by ultrasonic or other means. Where deterioration or lamination is found, steps should be taken to ensure a safe repair.

(b) See guide material under §§192.703, 192.713, 192.751, and 192.933.

§192.712
Analysis of predicted failure pressure.

[Effective Date: 07/01/20]

(a) **Applicability.** Whenever required by this part, operators of onshore steel transmission pipelines must analyze anomalies or defects to determine the predicted failure pressure at the location of the anomaly or defect, and the remaining life of the pipeline segment at the location of the anomaly or defect, in accordance with this section.

(b) **Corrosion metal loss.** When analyzing corrosion metal loss under this section, an operator must use a suitable remaining strength calculation method including, ASME/ANSI B31G (incorporated by reference, see § 192.7); R-STRENG (incorporated by reference, see § 192.7); or an alternative equivalent method of remaining strength calculation that will provide an equally conservative result.

(c) [Reserved]

(d) **Cracks and crack-like defects.**

(1) **Crack analysis models.** When analyzing cracks and crack-like defects under this section, an operator must determine predicted failure pressure, failure stress pressure, and crack growth using a technically proven fracture mechanics model appropriate to the failure mode (ductile, brittle or both), material properties (pipe and weld properties), and boundary condition used (pressure test, ILI, or other).

(2) **Analysis for crack growth and remaining life.** If the pipeline segment is susceptible to cyclic fatigue or other loading conditions that could lead to fatigue crack growth, fatigue analysis must be performed using an applicable fatigue crack growth law (for example, Paris Law) or other technically appropriate engineering methodology. For other degradation processes that can cause crack growth, appropriate engineering analysis must be used. The above methodologies must be validated by a subject matter expert to determine conservative predictions of flaw growth and remaining life at the...
maximum allowable operating pressure. The operator must calculate the remaining life of the pipeline by determining the amount of time required for the crack to grow to a size that would fail at maximum allowable operating pressure.

(i) When calculating crack size that would fail at MAOP, and the material toughness is not documented in traceable, verifiable, and complete records, the same Charpy v-notch toughness value established in paragraph (e)(2) of this section must be used.

(ii) Initial and final flaw size must be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle or both) and boundary condition used (pressure test, ILI, or other).

(iii) An operator must re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated by this analysis has expired. The operator must determine and document if further pressure tests or use of other assessment methods are required at that time. The operator must continue to re-evaluate the remaining life of the pipeline before 50% of the remaining life calculated in the most recent evaluation has expired.

(3) Cracks that survive pressure testing. For cases in which the operator does not have in-line inspection crack anomaly data and is analyzing potential crack defects that could have survived a pressure test, the operator must calculate the largest potential crack defect sizes using the methods in paragraph (d)(1) of this section. If pipe material toughness is not documented in traceable, verifiable, and complete records, the operator must use one of the following for Charpy v-notch toughness values based upon minimum operational temperature and equivalent to a full-size specimen value:

(i) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(ii) A conservative Charpy v-notch toughness value to determine the toughness based upon the material properties verification process specified in § 192.607;

(iii) A full size equivalent Charpy v-notch upper-shelf toughness level of 120 ft.-lbs.; or

(iv) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of the crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in accordance with § 192.18.

(e) Data. In performing the analyses of predicted or assumed anomalies or defects in accordance with this section, an operator must use data as follows:

(1) An operator must explicitly analyze and account for uncertainties in reported assessment results (including tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance) in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses, unless the defect dimensions have been verified using in situ direct measurements.

(2) The analyses performed in accordance with this section must utilize pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis is not available, an operator must obtain the undocumented data through § 192.607. Until documented material properties are available, the operator shall use conservative assumptions as follows:

(i) Material toughness. An operator must use one of the following for material toughness:

(A) Charpy v-notch toughness values from comparable pipe with known properties of the same vintage and from the same steel and pipe manufacturer;

(B) A conservative Charpy v-notch toughness value to determine the toughness based upon the ongoing material properties verification process specified in § 192.607;
(C) If the pipeline segment does not have a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 13.0 ft.-lbs. for body cracks and 4.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion defects;

(D) If the pipeline segment has a history of reportable incidents caused by cracking or crack-like defects, maximum Charpy v-notch toughness values of 5.0 ft.-lbs. for body cracks and 1.0 ft.-lbs. for cold weld, lack of fusion, and selective seam weld corrosion; or

(E) Other appropriate values that an operator demonstrates can provide conservative Charpy v-notch toughness values of crack-related conditions of the pipeline segment. Operators using an assumed Charpy v-notch toughness value must notify PHMSA in advance in accordance with § 192.18 and include in the notification the bases for demonstrating that the Charpy v-notch toughness values proposed are appropriate and conservative for use in analysis of crack-related conditions.

(ii) Material Strength. An operator must assume one of the following for material strength:

(A) Grade A pipe (30,000 psi), or

(B) The specified minimum yield strength that is the basis for the current maximum allowable operating pressure.

(iii) Pipe dimensions and other data. Until pipe wall thickness, diameter, or other data are determined and documented in accordance with § 192.607, the operator must use values upon which the current MAOP is based.

(f) Review. Analyses conducted in accordance with this section must be reviewed and confirmed by a subject matter expert.

(g) Records. An operator must keep for the life of the pipeline records of the investigations, analyses, and other actions taken in accordance with the requirements of this section. Records must document justifications, deviations, and determinations made for the following, as applicable:

(1) The technical approach used for the analysis;

(2) All data used and analyzed;

(3) Pipe and weld properties;

(4) Procedures used;

(5) Evaluation methodology used;

(6) Models used;

(7) Direct in situ examination data;

(8) In-line inspection tool run information evaluated, including any multiple in-line inspection tool runs;

(9) Pressure test data and results;

(10) In-the-ditch assessments;

(11) All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operational results;

(12) All finite element analysis results;

(13) The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting method;

(14) The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods;

(15) Safety factors used for fatigue life and/or predicted failure pressure calculations;

(16) Reassessment time interval and safety factors;

(17) The date of the review;

(18) Confirmation of the results by qualified technical subject matter experts; and

(19) Approval by responsible operator management personnel.

[Amtd. 192-125, Oct. 01, 2019]
GUIDE MATERIAL

This guide material is under review following Amendment 192-125.
§192.713
Transmission lines: Permanent field repair of imperfections and damages.

(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.


GUIDE MATERIAL

1 GENERAL

1.1 Welding.
  (a) Appropriate procedures for welding on pipelines in service should be used. Some important factors to be considered in these procedures are the use of a low-hydrogen welding process, the welding sequence, the effect of wall thickness and heat input, and the quenching effect of the gas flow.
  (b) Welding should be done only on sound metal far enough from the defect so that the localized heating will not have an adverse effect on the defect. The soundness of the metal may be determined by visual and other nondestructive inspection.
  (c) A reference is API Std 1104, "Welding of Pipelines and Related Facilities", Appendix B, "In-Service Welding" (see §192.7).

1.2 Additional precautions.
  (a) Care should be taken in excavating around the pipe so that it is not damaged.
  (b) Pounding on the pipe (e.g., to remove corrosion products or pipe coating, or to improve the fit of the sleeve) should be avoided.

1.3 Reliable engineering tests and analyses.
See guide material under §192.485.

2 REPLACEMENT (§192.713(a)(1))

(a) The operator should consider the possibility that some degree of impairment may have occurred beyond the area of immediate concern. The impairment may be due to a defect in the longitudinal weld, external or internal corrosion, or damage by excavating equipment at another location when excavation work covers a large area. The pipe on each side of the known impairment should be examined to determine the extent of the replacement.

(b) Operators should consider the following potential concerns when repairing a segment of transmission line by replacing pipe.
  (1) Passage of internal inspection devices (see §192.150) when replacing a segment of transmission line with pipe of a heavier wall thickness.
  (2) Welding when replacing a segment of transmission line with pipe of a heavier wall thickness or of a greater strength steel.

3 REPAIR (§192.713(a)(2))

3.1 General.
  (a) The use of an appropriately designed full-encirclement split sleeve is recognized as an acceptable
repair method. Other methods, including the use of composite-reinforced sleeve material, may also be available. However, operators are cautioned that not all repair methods are suitable for permanent repair of leaking or through-wall defects. Review the manufacturer’s installation requirements before deciding to use a composite sleeve to make permanent repair. The repair method selected should:

(1) Have or achieve a strength at least equal to that required for the MAOP of the pipe being repaired, and

(2) Be capable of withstanding the anticipated circumferential and longitudinal stresses, including additional stress due to external loading.

(b) In determining the length of the repair, the operator should consider that:

(1) Some degree of impairment might have occurred beyond the area of immediate concern (see 2 above), and

(2) Full-encirclement sleeves should not be less than 4 inches in length.

(c) A wide variety of repair methods has been used successfully in the natural gas pipeline industry. Sleeves may be used to reduce the stress in, or reinforce, a pipe defect that is not leaking, or to repair a leaking defect. It is important that any repair method or sleeve be carefully designed and tested to ensure its reliability for the conditions of installation.
of the system. Once established, frequencies should be reviewed periodically to affirm that they are still appropriate. Leak surveys may be accomplished in conjunction with patrolling, scheduled inspections, and other routine activities.

2 GAS LEAKAGE CONTROL GUIDELINES


§192.725
Test requirements for reinstating service lines. [Effective Date: 11/12/70]

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

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

GUIDE MATERIAL

No guide material necessary.

§192.727
Abandonment or deactivation of facilities. [Effective Date: 02/17/09]

(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 http://www.npms.phmsa.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 Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001; fax (202) 366-4566; e-mail InformationResourcesManager@phmsa.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) [Reserved].


GUIDE MATERIAL

1 GENERAL

(a) The following procedural guidance covers the maintenance of pipelines (including service lines) not actively being used to transport gas and the permanent abandonment of transmission pipelines, distribution mains, and distribution service lines. See 5 below for information regarding inactive pipelines.

(b) For planned shutdown in connection with abandonment or deactivation, see Guide Material Appendix G-192-12.

2 ABANDONMENT OF TRANSMISSION PIPELINES AND DISTRIBUTION MAINS

2.1 Check prior to abandonment.

Office records should be checked and necessary field checks should be made to ensure the pipelines or mains scheduled for abandonment are disconnected from all sources and supplies of gas, such as other pipelines, mains, crossover piping, meter stations, customer piping, control lines, and other appurtenances.

2.2 Residual gas or hydrocarbons.

Abandonment should not be completed until it has been determined that the volume of natural gas or
2.3 Purging.

Pipelines or mains may be purged using air, inert gas, or water. If air is used as the purging agent, precautions should be taken to ensure that no liquid hydrocarbons are present. See §192.629 and AGA XK1801, “Purging Manual” for purging of natural gas and liquid hydrocarbons.

2.4 Sealing.

Acceptable methods of sealing pipeline or main openings include, as applicable, the following.

(a) Using normal end closures, such as welded or screwed caps, screwed plugs, blind flanges, and mechanical joint caps and plugs.
(b) Welding steel plate to pipe ends.
(c) Filling ends with a suitable plug material.
(d) Pinching the ends closed.

2.5 Additional considerations in addition to purging and sealing.

In addition to purging and sealing, consideration should be given to the following.

(a) Filling the abandoned segment with water or an inert gas to prevent potential combustion hazard.
(b) Other action designed to prevent hazardous cave-ins resulting from pipe collapse caused by corrosion or external loading.

2.6 Segmenting the abandoned sections.

All valves left in the abandoned segment should be closed. If the segment is long and there are few line valves, consideration should be given to plugging the segment at intervals.

2.7 Removal of above-grade facilities and filling voids.

All above-grade valves, risers, and vault and valve box covers should be removed. Vault and valve box voids should be filled with suitable compacted backfill material.

3 ABANDONMENT OF DISTRIBUTION SERVICE LINES IN CONJUNCTION WITH MAIN ABANDONMENT

3.1 Curb valves and curb boxes.

All curb valves should be closed. The top section of curb boxes located in dirt areas should be removed and the void filled with suitable compacted backfill material. If boxes are set in concrete or asphalt, they should be filled with suitable compacted backfill material to an appropriate distance from the top of the box and the fill completed with suitable paving material.

3.2 Meter risers and headers.

Meter risers and headers should be dismantled and removed from the premises.

3.3 Service lines below grade through a basement wall.

Where a service line enters below grade through a basement wall, the end of the service line should be plugged and a cap should be installed as close to the face of the wall as practical. It is not necessary to remove pipe from the wall unless required by particular circumstances.

3.4 Outside meter set assembly and above-grade entrances.

Service lines terminating at an outside meter set assembly or an above-grade entrance should be cut and capped at an appropriate depth below grade.

4 ABANDONMENT OF SERVICE LINES FROM ACTIVE MAINS

4.1 Disconnecting.
Service lines abandoned from active mains should be disconnected as close to the main as practical.

4.2 Sealing.
The end of the abandoned portion of the service line nearest the main should be plated, capped, plugged, pinched, or otherwise effectively sealed.

4.3 Other actions.
(a) The remainder of the service line should be abandoned as recommended in 3 above.
(b) The operator should consider the development of criteria to map or otherwise document service line stubs that are not disconnected within close proximity to the main.

5 INACTIVE PIPELINES

Pipelines not actively used to transport gas might be informally referred to as “idled,” “inactive,” or “decommissioned.” These shut-down and usually isolated pipelines might still contain gas at reduced pressures. For pipelines that have not been abandoned (permanently removed from service), operators must continue to comply with relevant safety requirements of Part 192 (e.g., periodic maintenance, integrity management assessments, damage prevention program, public awareness program). See Advisory Bulletin ADB-2016-05 (81 FR 54512, August 16, 2016; reference Guide Material Appendix G-192-1, Section 2) for additional guidance on operational status.

5.1 General.
Each operator should consider the following elements when determining whether to abandon or continue maintaining an inactive pipeline.
(a) Location (e.g., business district, urban, suburban, rural).
(b) Type of piping material.
(c) Joining method (e.g., welding, fusion, compression couplings).
(d) Cathodic protection.
(e) Operating pressure.
(f) Likelihood of reactivation.
(g) Leakage and maintenance history.
(h) Proposed construction.

5.2 Continuing maintenance.
Provisions for continuing maintenance of inactive pipelines should be included in the procedural manual for operations, maintenance, and emergencies required under §192.605. (See guide material under §192.3 for definition of “inactive pipeline.”) Examples of such maintenance include the following.
(a) Regularly scheduled leak surveys and patrolling.
(b) Corrosion control monitoring of cathodically protected systems.
(c) Maps and records for damage prevention.
(d) Evaluating aboveground piping for the following.
   (i) Atmospheric corrosion.
   (ii) Susceptibility to damage from vehicles and other forces.
   (iii) Unauthorized activities.

6 INACTIVE SERVICE LINES

In addition to 5.2 above, the operator should consider the following for continuing maintenance of inactive service lines.
(a) Identifying and documenting the location of inactive service lines in a record management system.
(b) Developing criteria for abandonment.
GUIDE MATERIAL

1 APPLICABILITY

The following procedures apply primarily to vaults that have restricted openings (e.g., manholes) or are more than four feet deep. However, an operator should review the following procedures and select those that, for its particular situation, are applicable to vaults that have full opening covers and are less than four feet deep.

2 HAZARDOUS ATMOSPHERES

Hazardous atmospheres may exist in such vaults due to leakage from components within the vault itself, or from seepage (natural gas, nitrogen, other gases, gasolines, or other vapors, fumes, or mists) from outside the vault.

3 DEVELOPMENT OF SAFETY PROCEDURES

Procedures for appropriate safety measures should be developed and should include the following.

3.1 Procedures prior to entry.
   (a) Engine exhausts should be kept away from the vault opening.
   (b) All possible sources of ignition should be kept away from the work area, except as may be required in the performance of the work. See §192.751.
   (c) Sufficient safety equipment (e.g., dry chemical fire extinguishers, breathing apparatus, safety harnesses) should be available in the work area.
   (d) Flashlights, lighting fixtures, and extension cords should be of a type approved for hazardous atmospheres.
   (e) Before the cover is removed, the vault atmosphere should be tested for combustible gas. Use the holes or pry holes, or lift the edge of the cover slightly to admit the testing probe. In double cover manholes, it will be necessary to remove the outer cover and partially lift the inner cover to make the test.
   (f) Immediately after removal of the cover, tests for combustible gas and for oxygen deficiency should be made at various levels that can be reached from the surface.
   (g) Results of the tests made in accordance with 3.1(e) and (f) above should determine the procedures to be followed.
      (1) Combustibles at 60% of the Lower Explosive Limit (3.0% natural gas in air) or less. The vault may be entered without breathing apparatus after establishing, by test, that a safe oxygen level exists, or if continuous forced ventilation is maintained. Forced draft ventilation is decidedly superior to suction draft ventilation.
      (2) Combustibles in excess of 60% of the Lower Explosive Limit. The vault should not be entered unless ventilation maintains combustible level below 60% of the Lower Explosive Limit and a safe oxygen level exists. However, in the event the vault cannot be adequately ventilated and the facility cannot be taken out of service to effect necessary repairs, the vault may be entered with the use of an approved breathing apparatus and safety harness.

3.2 Procedures for vault entry and while working in the vault.
   (a) Ladders should be used when entering or leaving vaults.
   (b) Upon entering a vault, workers should inspect or test the interior for abnormal or hazardous conditions.
   (c) In all cases where workers enter vaults, at least one person should remain on the surface and, under ordinary circumstances, not leave the work location. In the event workers require a breathing apparatus and safety harness in accordance with 3.1(g)(2) above, at least two persons should remain on the surface (one being in a position to observe activity in the vault at all times).
(d) In all cases where workers enter vaults, the atmosphere should be retested for combustible gases and oxygen deficiency at intervals not to exceed one hour, or instrumentation providing continuous monitoring should be used.
(e) Only approved flashlights or lighting equipment should be used. Electrical connections and disconnections should be made outside the vault. See guide material under §192.751.

§192.750
Launcher and receiver safety.

[Effective Date: 07/01/2020]

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (e.g. inspection tools, scrapers, or spheres), if pressure has not been relieved.

[Amndt. 192-125, Oct. 01, 2019]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125.

§192.751
Prevention of accidental ignition.

[Effective Date: 11/12/70]

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.

GUIDE MATERIAL

1 GENERAL

1.1 Smoking and open flames.
Smoking and open flames should be prohibited in the following locations.
(a) In structures or areas containing gas facilities where possible leakage or presence of gas constitutes a hazard of fire or explosion.
(b) In the open when accidental ignition of gas-air mixture might cause personal injury or property damage.
1.2 Accidental electric arcing.

To prevent accidental ignition by electric arcing, the following should be considered.

(a) Flashlights, portable floodlights, extension cords, and any other electrically powered tool or equipment should be of a type approved for use in hazardous atmospheres. Care should be taken to ensure that electrical connections and disconnections are not made, and are prevented from occurring, in hazardous atmospheres.

(b) Internal combustion engines that power trucks, cars, compressors, pumps, generators, and other equipment should not be operated in suspected or known hazardous atmospheres.

(c) Bonding to provide electrical continuity should be considered around all cuts separating metallic pipes that may have natural gas present. This bond should be installed prior to cutting and maintained until all reconnections are completed or a gas free environment exists. Bond cables should be installed in a manner to ensure that they do not become detached during construction and that they provide minimal electrical resistance between pipe sections.

1.3 Static electricity on plastic pipe.

A static electric charge can build up on both the inside and outside of plastic pipe due to the dielectric properties of plastic. Discharging of the static electricity going to ground can cause an arc that will cause ignition if a flammable gas-air mixture is present. In plastic pipe operations, it is essential to avoid the accumulation of a flammable gas-air mixture and the arcing of a static electrical discharge. When conditions exist such that a flammable gas-air mixture may be encountered and static charges may be present, such as when repairing a leak, squeezing-off an open pipe, purging, making a connection, etc., arc preventing safety precautions are necessary. The following should be considered.

(a) Leaking or escaping gas should be eliminated by closing valves or excavating and squeezing-off in a separate excavation at a safe distance from the escaping gas.

(b) If escaping gas cannot be effectively controlled or eliminated and it is necessary to work in an area of escaping gas, safety provisions should be considered such as dissipating or preventing the accumulation of a static electrical charge, venting the gas from the trench, and grounding those tools used in the area. Additionally, flame-resistant clothing treated to prevent static buildup and respiratory equipment should be used. Acceptable methods of dissipating or preventing the accumulation of static electricity include wetting the exposed area with an electrically conductive liquid (e.g., soapy water with glycol added when ambient temperatures are below freezing) and using a anti-static polyethylene (PE) film or wet non-synthetic cloth wound around or laid in contact with the entire section of exposed pipe and grounded with a brass pin driven into the ground. Commercially available electrostatic discharge systems may be considered as a means of eliminating static electricity from both the inside and outside of PE pipe.

(c) A plastic pipe vent or blowdown stack should not be used due to the possibility that venting gas with a high scale or dust content could generate an internal static electrical charge that could ignite the escaping gas. Metal vent stacks should be grounded before placement in the escaping gas stream. Venting should be done downwind at a safe distance from personnel and flammable material.

(d) To reduce potential sources of ignition, all tools, including squeeze-off tools, used in gaseous atmospheres should be grounded or the non-sparking type.

1.4 Other sources of ignition.

Care should be taken in selecting the proper hand tools for use in hazardous atmospheres and in handling tools to reduce the potential for a spark.

1.5 Fire extinguishers.

If escaping gas in the area of the work is possible, a fire extinguisher should be available upwind and adjacent to the area.

1.6 Verification of the presence of gas.

Prior to welding, cutting, or performing other work on isolated sections of gas piping, a check should be made with a gas detector for the presence of a combustible gas mixture inside the pipe. Work should
begin only when safe conditions are indicated. If the work takes place over an extended period of time, the line should be periodically monitored to ensure that a combustible gas mixture does not accumulate.

1.7 Accidental ignition of discharged gas.
Operators should consider using the following measures to help avoid accidental ignition when gas is discharged in areas subject to public motor vehicle or pedestrian traffic.
(a) Posting warning signs.
(b) Directing motor vehicles and pedestrians away from the area by considering the following.
   (1) Law enforcement.
   (2) Traffic flaggers.
   (3) Signs (e.g., detour, road closed).
   (4) Barricades.

2 WELDING, CUTTING, AND OTHER HOT WORK

2.1 General.
Prior to welding, cutting, or other hot work in or around a structure or area containing gas facilities, a thorough check should be made with a gas detector for the presence of a combustible gas mixture. Prior to entering pipe, tanks, or similar confined spaces, appropriate instruments should be used to ensure a safe, breathable atmosphere. Work should begin only when safe conditions are indicated. The atmosphere should be tested periodically for oxygen deficiency and combustible gas mixtures.

2.2 Pipelines filled with gas.
When a pipeline or main is to be kept full of gas during welding or cutting operations, the following are recommended.
(a) A slight flow of gas should be kept moving toward the cutting or welding operation.
(b) The gas pressure at the site of the work should be controlled by suitable means.
(c) All slots or open ends should be closed with tape, tightly fitted canvas, or other suitable material immediately after a cut is made.
(d) Two openings should not be uncovered at the same time.

2.3 Pipelines containing air.
(a) Before the work is started, and at intervals as the work progresses, the atmosphere in the vicinity of the zone to be heated should be tested with a combustible gas indicator or by other suitable means.
(b) Unless a suitable means (e.g., an air blower) is used to prevent a combustible mixture in the work area, welding, cutting or other operations that could be a source of ignition should not be performed on a pipeline, main, or auxiliary apparatus that contains air and is connected to a source of gas.
(c) When the means noted in 2.3(b) above are not used, one or more of the following precautions are suggested, depending upon the job site circumstances.
   (1) The pipe or other equipment upon which the welding or cutting is to be done should be purged with an inert gas.
   (2) The pipe or other equipment upon which the welding or cutting is to be done should be continuously purged with air in such a manner that a combustible mixture does not form in the facility at the work area.

3 ISOLATING PIPELINE SEGMENTS ON PLANNED WORK TO MINIMIZE THE POTENTIAL OF IGNITION

3.1 General.
Planned work on gas facilities should incorporate procedures to shut off or minimize the escape of gas. No portion of a pipeline, large-diameter service line, or main should be cut out under pressure, unless the flow of gas is shut off or minimized by the use of line valves, line plugging equipment, bags, stoppers, or pipe squeezers. Where 100% shutoff is not feasible, the following precautions are recommended.
(a) Plan the job to minimize the escape of gas and sequence steps to limit the time and amount of gas
to which personnel are exposed.

(b) Ensure that the size and position of the cut allows the gas to vent properly even with an employee in the excavation.

(c) Protect personnel working in a gaseous atmosphere under an overhang, in a tunnel, or in a manhole.

3.2 Isolating pipeline segments.

(a) Preliminary action. The operator should conduct a prework meeting(s) to review the following with the personnel involved.
   (1) The method of isolation.
   (2) The purpose of each activity.
   (3) Drawings, procedures, and schematics, as applicable.
   (4) Responsibilities of each individual, including the designation of an individual to be in charge of the operation.

(b) Isolation precautions.
   (1) The operator should ensure that the isolation equipment is appropriate and sized correctly for the job.
   (2) Isolation equipment left unattended should have a positive means of preventing unauthorized operation.
   (3) Positive means should be provided at the work site to alert and protect personnel from unintentional pressuring. Consideration should be given to the use or installation of items such as:
      (i) Relief valves.
      (ii) Rupture discs.
      (iii) Pressure gauges.
      (iv) Pressure recorders.
      (v) Vents.
      (vi) Pressure alerting devices.
      (vii) Other pressure detecting devices.
   (4) Isolation equipment should be inspected and maintained prior to use.
   (5) Temporary closures capable of withstanding full line pressure should have a means to determine pressure buildup, such as gauges and vents.
   (6) Consideration should be given to the following to prevent the uncontrolled release of liquid hydrocarbons when cutting into offshore pipelines or other pipelines that might contain significant quantities of these liquids.
      (i) The elevation difference between the blowdown valve and cut location.
      (ii) The impact of water displacement on liquid hydrocarbons in those instances where water may enter into the pipeline segment.

(c) Monitoring isolated segments.
   (1) Monitoring procedures should be established based on the pressure, volumes, closures, and other pertinent factors.
   (2) Personnel assigned to operate isolation equipment should have a means to determine pressure buildups, such as gauges and vents.
   (3) Personnel monitoring at remote locations should have communication with the work site and the individual in charge of the operation.

4 NOTIFICATIONS PRIOR TO PURGE OR BLOWDOWN

4.1 Public officials.
Local public officials should be notified prior to a purge or blowdown in those situations where the normal traffic flow through the area might be disturbed, or where it is anticipated that there will be calls from the public regarding the purge or blowdown.

4.2 Public in vicinity of gas discharge.
The public in the vicinity of the gas discharge should be notified prior to a purge or blowdown, if it is
anticipated that the public might be affected by the process. The primary considerations for determining the need for notification are noise, odor, and the possibility of accidental ignition.

5 REFERENCE


§192.753

Caulked bell and spigot joints.

[Effective Date: 10/15/03]

(a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi (172 kPa) gage must be sealed with:
   (1) A mechanical leak clamp; or
   (2) A material or device which:
      (i) Does not reduce the flexibility of the joint;
      (ii) Permanently bonds, either chemically or mechanically, or both, with the bell and spigot metal surfaces or adjacent pipe metal surfaces; and
      (iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§192.53(a) and (b) and 192.143.

(b) Each cast iron caulked bell and spigot joint that is subject to pressures 25 psi (172 kPa) gage or less and is exposed for any reason must be sealed by a means other than caulking.


GUIDE MATERIAL

No guide material necessary.

§192.755

Protecting cast-iron pipelines.

[Effective Date: 06/01/76]

When an operator has knowledge that the support for a segment of a buried cast-iron pipeline is disturbed:

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:
   (1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;
   (2) Impact forces by vehicles;
   (3) Earth movement;
   (4) Apparent future excavations near the pipeline; or
   (5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

(b) As soon as feasible, appropriate steps must be taken to provide permanent protection for the disturbed segment from damage that might result from external loads, including compliance with
applicable requirements of §§192.317(a), 192.319, and 192.361(b) — (d).

[Issued by Amdt. 192-23, 41 FR 13588, Mar. 31, 1976]

GUIDE MATERIAL


§192.756
Joining plastic pipe by heat fusion: equipment maintenance and calibration.
[Effective Date: 01/22/19]

Each operator must maintain equipment used in joining plastic pipe in accordance with the manufacturer’s recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.

[Amendment 192-124, 83 FR 58694, Nov. 20, 2018]

No guide material available at present.

§192.761
(Removed.)
[Effective Date: 02/14/04]
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Performance monitoring. The operator may also consider planned or impromptu observation of performance of covered and related tasks by individuals and developing documentation that could be useful in a work performance history review.

3.3 Evaluation categories.

The three types of qualifications are as follows.

(a) Transitional qualification means qualification in a covered task completed by October 28, 2002, of an individual who had been performing that task on a regular basis prior to October 26, 1999.

(b) Initial qualification means the first qualification of an individual in a covered task that is not transitional qualification.

(c) Subsequent qualification means evaluation of an individual's qualification to perform a covered task, after "transitional" or "initial" qualification, at the interval established by the operator. The subsequent qualification process may use different evaluation criteria than used for transitional or initial qualification. The interval for the first subsequent qualification does not need to start until October 28, 2002. Therefore, if an operator chooses October 28, 2002, as the start date for the subsequent qualification interval applicable to previously qualified individuals, the first subsequent qualification interval for those individuals may exceed the intervals established under the operator's written program. However, for qualifications on or after October 28, 2002, the established subsequent evaluation intervals would apply.

Subsequent evaluations may be used as follows.

(1) Verify that all necessary changes since the last qualification have been communicated to affected personnel.

(2) Identify qualification concerns.

(3) Evaluate the employee's performance over the preceding interval.

4 CONTRACTORS

The operator should review the qualification criteria used by contractors to ensure consistency with its own criteria.

§192.805 Qualification program.

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

(a) Identify covered tasks;

(b) Ensure through evaluation that individuals performing covered tasks are qualified;

(c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

(d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;

(e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

(f) Communicate changes that affect covered tasks to individuals performing those covered tasks;

(g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed; and
(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and

(i) After December 16, 2004, notify the Administrator or a state agency participating under 49 U.S.C. Chapter 601 if the operator significantly modifies the program after the Administrator or state agency has verified that it complies with this section. Notifications to PHMSA must be submitted in accordance with § 192.18.

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999; Amdt. 192-100, 70 FR 10332, Mar. 3, 2005 with Amdt. 192-100 DFR Confirmation, 70 FR 34693, June 15, 2005; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015, Amdt. 192-125, Oct. 01, 2019]

GUIDE MATERIAL

This guide material is under review following Amdt. 192-125.

See Cautionary Note at the beginning of Subpart N.

1 GENERAL

An operator may use vendor written programs to meet this regulation. However, the operator should be aware that by adopting a vendor program (including those produced by industry associations and consortiums), it is still responsible for ensuring that the elements of the program meet the requirements of the subpart as applied to its systems, and supplementing the vendor program where it does not. Since the Regulations are applicable to pipeline operators, it is not necessary for contractors to have written programs. In complying with §192.805 requirements, some operators may choose to request that each contractor develop its own written program. If an operator chooses to request written programs from contractors or accept third-party evaluations, the operator should ensure that the contractor’s program requirements are consistent with its own. This may require that copies of the evaluation tools of the contractor or the third-party evaluator be reviewed.

2 ELEMENTS OF THE WRITTEN PROGRAM

2.1 Identification of covered tasks (§192.805(a)).

The operator is responsible for identifying which O&M tasks performed on its facilities are covered tasks based on the four–part test in §192.801(b). Covered tasks may vary among operators.

(a) Four-part test.

When applying the four-part test for a covered task and evaluating whether a task is covered, the operator may consider the following definitions.

(1) Performed on a pipeline facility means that the task is performed on part of a facility that is connected to the pipeline system. A task that is performed on a component that is removed from the system is not considered to be a task performed on a pipeline facility. To meet this criterion, the performance of the task should directly affect the pipeline facility.

(2) An operations or maintenance task means a task that is performed on an existing portion of a pipeline facility. Most covered O&M tasks performed in order to comply with these rules are found in Subparts L and M of Part 192. However, some tasks may be found in other subparts (e.g., Subparts E, I, J, and K). Additionally, not all tasks required to comply with Subparts L and M are considered O&M tasks (e.g., tasks involving emergency response, and some tasks related to installation of replacement pipe or components).

(i) An operating task is one that causes a system or a part of a system to function. Opening and closing a valve is an example of an operating task.
§192.909
How can an operator change its integrity management program?  
[Effective Date: 07/01/2020]

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

(b) **Notification.** An operator must notify OPS, in accordance with §192.18, of any change to the program that may substantially affect the program’s implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must provide the notification within 30 days after adopting this type of change into its program.


**GUIDE MATERIAL**

This guide material is under review following Amdt. 192-125.

1 **CHANGES TO BE DOCUMENTED**

It is anticipated that there will be a number of changes over time to an operator’s Integrity Management Program (IMP). Documentation of changes and the reasons for them should include decisions, analyses, and processes used to change elements of the IMP. The operator should maintain previous versions of the IMP for the life of the pipeline. See guide material under §192.947. This documentation can be in electronic format. Factors that might cause a change to the IMP include the following.

(a) Information obtained from the integrity assessments.

(b) Operating experience.

(c) The operator’s understanding about the specific integrity threats and the relative importance of those threats may change.

(d) The operator’s understanding about a specific integrity assessment tool changes, and the operator chooses to use another type.

(e) Risks are different than previously understood and an operator needs to reprioritize assessments.

(f) Identification of a new HCA, which adjusts the baseline assessment plan.

(g) Development of additional program elements.

2 **NOTIFICATION**

When applicable, notification of program changes is required to PHMSA-OPS (and typically providing an informational copy to the state). Where PHMSA-OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that state, the operator must also notify the state pipeline safety agency. A reference for state contacts is available at www.napsr.org.

2.1 **Changes requiring notification.** Examples of situations that may lead to changes substantially affecting program implementation, or significantly modifying the program or schedule, are as follows.

(a) An incident on a lower-risk pipeline that would cause a reprioritization of the assessment schedule.
(b) Changes that affect the way an operator is conducting its IMP, e.g., a change to grading criteria for integrity assessment methods that subsequently affects the inspection, remediation, or prevention and mitigation activities.

(c) A merger of two companies that causes reprioritization of the assessment schedule under the merged IMP.

Notification should include the changes to the program and reasons for such changes. See guide material under §192.949.

2.2 Changes not requiring notification.

Minor changes that do not significantly affect program implementation or plans for carrying out program elements do not require a notification. Examples include the following.

(a) Editorial revisions.

(b) Schedule changes due to weather or permit delays that have no impact on meeting deadlines.

(c) Priority changes due to updated risk assessment information.

§192.911

What are the elements of an integrity management program?

[Effective Date: 07/10/06]

An operator’s initial integrity management program begins with a framework (see §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, see §192.7) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with §192.905.

(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.

(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.

(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.

(f) A process for continual evaluation and assessment meeting the requirements of §192.937.

(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.

(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.

(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.

(j) Record keeping provisions meeting the requirements of §192.947.

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

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

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

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
2 OTHER QUALIFICATIONS

2.1 Personnel who require qualification.
The IMP must define the qualification criteria (e.g., knowledge, skills, abilities) for personnel who do the following.
(a) Perform assessments.
(b) Evaluate assessment results.
(c) Make technical decisions based upon assessment results (e.g., dig locations, repair methods, prioritization of fieldwork).
(d) Implement preventive and mitigative measures.
(e) Supervise excavation work associated with assessments.

For qualification of personnel performing ILI assessments, see Guide Material Appendix G-192-14.

2.2 Demonstrating qualifications.
Examples of means used to demonstrate qualification of employees and contractors include the following.
(a) Training records.
(b) Documented experience.
(c) Qualification records.
(d) Certifications from industry organizations.
(e) Education records.

3 DOCUMENTATION

The operator might consider developing a matrix of integrity management related tasks, which outline the qualification requirements, and what operator or contractor position may perform each task.
(a) Documentation of the knowledge and training of integrity management personnel should demonstrate the following.
   (1) Competence in performing the assigned IMP element.
   (2) Awareness of the IMP requirements.
   (3) The process used to qualify the person for the IMP element.
(b) Operators using contractors in the IMP should document that the contractor employees are aware of and qualified for the applicable sections of the operator’s IMP.
§192.917
How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

[Effective Date: 07/01/2020]

(a) **Threat identification.** An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 2, which are grouped under the following four categories:

1. Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;
2. Static or resident threats, such as fabrication or construction defects;
3. Time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and
4. Human error.

(b) **Data gathering and integration.** To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) **Risk assessment.** An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

(d) **Plastic Transmission Pipeline.** An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) **Actions to address particular threats.** If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

1. **Third party damage.** An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment. An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

2. **Cyclic fatigue.** An operator must analyze and account for whether cyclic fatigue or other loading conditions (including ground movement, and suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, crack, or other defect in the covered segment. The analysis must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from
the analysis together with the criteria used to evaluate the significance of the threat(s) to the
covered segment to prioritize the integrity baseline assessment or reassessment. Failure
stress pressure and crack growth analysis of cracks and crack-like defects must be
conducted in accordance with § 192.712. An operator must monitor operating pressure
cycles and periodically, but at least every 7 calendar years, with intervals not to exceed 90
months, determine if the cyclic fatigue analysis remains valid or if the cyclic fatigue analysis
must be revised based on changes to operating pressure cycles or other loading conditions.

(3) Manufacturing and construction defects. An operator must analyze the covered segment
to determine and account for the risk of failure from manufacturing and construction defects
(including seam defects) in the covered segment. The analysis must account for the results of prior
assessments on the covered segment. An operator may consider manufacturing and construction
related defects to be stable defects only if the covered segment has been subjected to hydrostatic
pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP, and the covered
segment has not experienced a reportable incident attributed to a manufacturing or construction
defect since the date of the most recent subpart J pressure test. If any of the following changes
occur in the covered segment, an operator must prioritize the covered segment as a high risk segment
for the baseline assessment or a subsequent reassessment.

(i) The pipeline segment has experienced a reportable incident, as defined in § 191.3,
since its most recent successful subpart J pressure test, due to an original manufacturing-related
defect, or a construction-, installation-, or fabrication-related defect;
(ii) MAOP increases; or
(iii) The stresses leading to cyclic fatigue increase.

(4) Electric Resistance Welded (ERW) pipe. If a covered pipeline segment
contains low frequency ERW pipe, lap welded pipe, pipe with longitudinal joint factor less than 1.0
as defined in § 192.113, or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S,
Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with
such pipe has experienced seam failure (including seam cracking and selective seam weld
corrosion), or operating pressure on the covered segment has increased over the maximum
operating pressure experienced during the preceding 5 years (including abnormal operation as
defined in §192.605(c)), or MAOP has been increased, an operator must select an assessment
technology or technologies with a proven application capable of assessing seam integrity and seam
corrosion anomalies. The operator must prioritize the covered segment as a high risk segment
for the baseline assessment or a subsequent reassessment. Pipe with seam cracks must be evaluated
using fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth
analysis to estimate the remaining life of the pipe in accordance with § 192.712.

(5) Corrosion. If an operator identifies corrosion on a covered pipeline segment that could
adversely affect the integrity of the line (conditions specified in §192.935), the operator must evaluate
and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar
material coating and environmental characteristics. An operator must establish a schedule for
evaluating and remediating, as necessary, the similar segments that is consistent with the operator’s
established operating and maintenance procedures under Part 192 for testing and repair.

(6) Cracks. If an operator identifies any crack or crack-like defect (e.g., stress corrosion
cracking or other environmentally assisted cracking, seam defects, selective seam weld
corrosion, girth weld cracks, hook cracks, and fatigue cracks) on a covered pipeline segment
that could adversely affect the integrity of the pipeline, the operator must evaluate, and remediate, as
necessary, all pipeline segments (both covered and non-covered) with similar characteristics
associated with the crack or crack-like defect. Similar characteristics may include operating and
maintenance histories, material properties, and environmental characteristics. An operator must
establish a schedule for evaluating, and remediating, as necessary, the similar pipeline segments
that is consistent with the operator’s established operating and maintenance procedures under
this part for testing and repair.
GUIDE MATERIAL

This guide material is under review following Amdt 192-125.

Note: References to ASME B31.8S throughout this section of guide material are specific to the edition of ASME B31.8S as incorporated by reference (IBR) in §192.7. Section 192.917(b) requires that the operator comply with the IBR edition of ASME B31.8S, Appendix A even though Appendix A is titled as "non-mandatory." See 3.2 of the guide material under §192.907.

1 GENERAL

(a) Threats are analyzed to determine which threats may contribute to the failure of a pipe segment, which assessment techniques are appropriate, and which preventative and mitigative measures should be implemented. Threat analysis requires data integration and allows for the prioritization of both assessments and mitigation measures (§192.917(b)). Operators should develop processes to ensure information acquired about both covered and non-covered segments is considered in determining risk and appropriate preventative and mitigative measures.

(b) Section 192.917(b) requires that operators using a prescriptive-based program consider the information within ASME B31.8S, Appendix A. When gathering data to meet ASME B31.8S, Appendix A, if the operator is missing data, conservative assumptions should be used and documented. Operators using a performance-based program must meet or exceed the prescriptive-based program data requirements per §192.913(b).

(c) An operator may determine that pipeline segments are not susceptible to specific threats and should provide justification and documentation for eliminating the threat. The lack of required data should not justify eliminating a threat.

(d) In the following guide material, sections 2 through 11 deal with threats to steel transmission pipelines. Section 12 deals with threats to plastic transmission pipelines. Section 13 addresses data integration, Section 14 addresses risk assessment, and Section 15 provides a list of references.
2 IDENTIFICATION OF THREATS TO STEEL PIPELINES

Section 192.917 requires operators to address potential threats to pipeline integrity. See 15.1.1 below for reference containing a representative list of pipeline threats that includes examples and comments. Threats for steel pipelines are commonly grouped into the following categories.

(a) Time-dependent.
(b) Stable.
(c) Time-independent.
(d) Other.

2.1 Time-dependent threats.
Time-dependent threats are those that may grow more severe over time, such as corrosion. Analysis based on sound engineering practices may be used to help predict when these threats might become critical. Corrosion threats include the following.

(a) External corrosion.
(b) Internal corrosion.
(c) Stress corrosion cracking.

2.2 Stable threats.
A threat that has passed post-construction testing is considered stable. However, these stable threats may change as external factors (e.g., loading due to earth movements, temperature changes, pressure changes) act upon it. These threats include the following.

(a) Manufacturing defects.
(b) Welding and fabrication (construction) defects.
(c) Equipment failures.

2.3 Time-independent threats.
Time-independent threats are generally associated with events that may take place along the pipeline segment and can happen at any time. These threats include the following.

(a) Excavation damage.
(b) Incorrect operations (includes human error).
(c) Weather-related and outside force.

Note that §192.917 identifies "Human Error" as a fourth threat category. This guide material follows the ASME B31.8S threat categories and addresses the human error threat in conjunction with the incorrect operations threat.

2.4 Other threats.
Section 192.917(a) requires operators to analyze the pipeline for other threats that may not fit into one of the above categories.
3 EXTERNAL CORROSION

In evaluating the threat of external corrosion, ASME B31.8S, Appendix A1 provides a list of data that the operator is required to gather and evaluate. This threat applies to both belowground and aboveground installations.

3.1 Year of installation.
Since the threat is time dependent, the threat may increase the longer the pipe is in service. If the installation year is not known, conservative estimates should be used.

3.2 Coating type.
While coated pipe is generally less susceptible to external corrosion, all coatings are not equally effective. Coatings with insufficient adhesion or strength could result in disbondment that shields the cathodic protection (CP) current. (See guide material under §192.112). The coating application method should also be considered because a field-applied coating might not have the same performance as a mill-applied coating of the same type. Bare pipe may be considered as a coating type of "none." Thermal insulation on buried pipelines might also influence the effectiveness of the CP system because the thermal insulation might absorb water and accelerate corrosion.

3.3 Coating condition.
The following should be considered in evaluating the coating condition.
(a) Findings from prior assessments.
(b) Data from close-interval survey (CIS) and coating surveys.
### ASSESSMENT APPLICABILITY

(Based on ASME B31.8S-2004, Section 6 — see §192.7 for IBR)

<table>
<thead>
<tr>
<th>Threat abbreviations:</th>
<th>EC – External Corrosion</th>
<th>IC – Internal Corrosion</th>
<th>SCC – Stress Corrosion Cracking</th>
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<tr>
<td>MFG – Manufacturer Defect</td>
<td>CON – Construction Defect</td>
<td>EQP – Equipment Defect</td>
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<tr>
<td>EXD – Excavation Damage</td>
<td>WOF – Weather Related &amp; Outside Force</td>
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#### Threat abbreviations:
- **EC** – External Corrosion
- **IC** – Internal Corrosion
- **SCC** – Stress Corrosion Cracking
- **MFG** – Manufacturer Defect
- **CON** – Construction Defect
- **EQP** – Equipment Defect
- **EXD** – Excavation Damage
- **WOF** – Weather Related & Outside Force
- **IO** – Incorrect Operation

<table>
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<th>Assessment Methods</th>
<th>Primary Threats</th>
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<td>In-Line Inspection (ILI) Tools</td>
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<td>Magnetic Flux Leakage, Std Res.</td>
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<tr>
<td>Magnetic Flux Leakage, High Res.</td>
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<tr>
<td>Ultrasonic Compression Wave</td>
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<td>Ultrasonic Shear Wave Tool</td>
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<td>Deformation or Geometry</td>
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<th>Direct Assessment</th>
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<tr>
<td>SCCDA</td>
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<td>Confirmatory Direct Assessment</td>
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</tbody>
</table>

1 ECDA can discover coating damage, including that caused by excavation activities; however, ECDA does not directly identify excavation damage.

2 Confirmatory direct assessment can be used for assessments conducted at no longer than seven-year intervals when reassessments conducted using ILI, Pressure Test, or DA specified methods are scheduled to occur at intervals longer than 7 years, and when the threats of concern are corrosion.

| TABLE 192.919i |

#### 4 INTEGRITY ASSESSMENT SCHEDULE

(a) The precision of the dates in the schedule may vary depending on how far in the future the assessments are scheduled.

(b) Consider updating the baseline assessment plan schedule annually. Include all covered segments not already assessed, new segments added within the past year, and completed baseline assessments.

#### 5 SAFETY AND ENVIRONMENTAL RISKS

When assessments are to be conducted by outside service providers, copies of their Health, Safety and Environmental procedure should be obtained, reviewed, and retained.
(a) **Assessment methods.** An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See §192.917).

(1) Internal inspection tool or tools capable of addressing those threats to which the pipeline is susceptible. The use of internal inspection tools is appropriate for threats such as corrosion, deformation and mechanical damage (including dents, gouges and grooves), material cracking and crack-like defects (e.g., stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible. When performing an assessment using an in-line inspection tool, an operator must comply with §192.493. In addition, an operator must analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies;

(2) Pressure test conducted in accordance with subpart J of this part. The use of subpart J pressure testing is appropriate for threats such as internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects, threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, (incorporated by reference, see § 192.7) to justify an extended reassessment interval in accordance with §192.939.

(3) Spike hydrostatic pressure test conducted in accordance with §192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects, including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and the pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with the applicable requirements specified in §§192.925, 192.927 and 192.929; or

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in
(b) Prioritizing segments. An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) Assessment for particular threats. In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) Time period. An operator must prioritize all the covered segments for assessment in accordance with §192.917(c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) Prior assessment. An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) Newly-identified areas. When an operator identifies a new high consequence area (see §192.905), an operator must complete the baseline assessment of the line pipe in the newly-identified high consequence area within ten (10) years from the date the area is identified.

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

(h) Plastic transmission pipeline. If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

(i) Baseline assessments for pipeline segments with a reconfirmed MAOP. An integrity assessment conducted in accordance with the requirements of §192.624(c) may be used as a baseline assessment under this section.

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GUIDE MATERIAL

This guide material is under review following Amdt. 192-125.

Note: References to ASME B31.8S throughout this section of guide material are specific to the edition of ASME B31.8S as incorporated by reference (IBR) in §192.7. See 3.2 of the guide material under §192.907.

1 ASSESSMENT METHOD

One, or more, of the methods listed below can be used for the assessment method. See Table 192.919i for related assessment applicability of (a), (b), and (c) below.
(a) In-line inspections (ILI).
(b) Pressure testing.
(c) Direct Assessment (DA).
(d) Other technologies.

1.1 In-line inspection.
(a) Threat assessments.
Applicable ILI tools can be used to assess the following threats.
(1) External corrosion.
(2) Internal corrosion.
(3) Stress corrosion cracking.
(4) Manufacturing defects.
(5) Construction defects.
(6) Excavation damage.
(7) Weather and outside forces.
(b) ILI tools.
Applicable tools and threats are listed in ASME B31.8S, Paragraph 6.2. Tools listed in that paragraph represent tested technology for the threats which the tools are capable of detecting. Other tools might meet the requirements of ASME B31.8S, Paragraph 6.2, provided they have a history of success and are capable of detecting the appropriate threat over the full length and circumference of the segment. If the tool does not have a history of success, it might be considered "other technology" and the requirements for using other technologies would need to be met.
(c) Advantages of ILI.
(1) Assessments can generally be conducted without taking the pipeline out of service.
(2) Long segments of pipe can be assessed in a single run.
(3) More than one threat can be addressed in a single run.
(4) Multiple tools can be run at the same time.
(5) May assess multiple HCAs in a single run.
(d) Disadvantages of ILI.
(1) Extensive pipe modifications may be required (e.g., installation of launcher/receiver, removal of restrictions).
(2) Flow rates and pressures must be within an acceptable range.
(3) Multiple tools may be needed to address multiple threats.
(4) Pipeline may need to be internally cleaned.
(5) Some tools require a liquid couplant.
(6) Scheduling limitations may include service interruptions and tool availability.
(7) Potential for failure or malfunction of ILI equipment.
(e) For information on ILI tools and their use, see Guide Material Appendix G-192-14.

1.2 Pressure testing.
(a) Threat assessments.
Pressure testing can be used to assess the following threats.

(1) External corrosion.

(2) Internal corrosion.

(3) Stress corrosion cracking.

(4) Manufacturing defects.

(5) Construction defects.

(6) Equipment defects.

(b) Advantages of pressure testing.

(1) Extensive pipeline modifications are generally not required.

(2) Results are easy to interpret.

(3) Multiple threats can be addressed at one time.

(c) Disadvantages of pressure testing.

(1) Pipeline must be taken out of service.

(2) Acquisition and disposal of test medium.

(3) Assessment provides only a pass/fail result.

(4) Provides no information on non-critical defects (e.g., a 50% corrosion pit that did not fail).

(5) Hydrostatic test dewatering and drying.

(6) A failure during a pressure test may present safety and environmental risks.

(7) Elevation changes may limit the amount of pipe that can be assessed in a single test.

(8) Pressure testing could propagate existing flaws.

(9) Scheduling limitations.

(d) Test pressure.

In addition to considering the requirements of Subpart J, the operator may consider the reassessment interval indicated in ASME B31.8S, Section 5, Table 3 when choosing a test pressure. Choosing a test pressure higher than the pressure required by Subpart J may allow for a longer reassessment interval.

(e) Conducting pressure tests.

See guide material under §§192.503, 192.505, and 192.919 plus Guide Material Appendices G-192-9 and G-192-9A.

1.3 Direct assessment.

(a) Threat assessments.

DA can be used to assess the following threats.

(1) External corrosion.

(2) Internal corrosion.

(3) Stress corrosion cracking.

(4) Coating damage from excavation (see §192.917).

(b) Advantages of DA.

(1) Can be conducted without taking the pipeline out of service.

(2) May be able to detect corrosive conditions before corrosion occurs.

(3) Less intrusive to the operating pipeline.

(c) Disadvantages of DA.

(1) May require more excavations than ILI or pressure testing.

(2) Only addresses corrosion threats.

(3) Requires at least 2 complementary indirect inspection tools for ECDA.

(4) ECDA is limited in areas of cased crossings.

(5) May not work in inaccessible locations such as large bodies of water.

(6) May not be able to assess pipe at greater than normal depths.
5 DEFECTS REQUIRING NEAR-TERM REMEDIATION

(a) A near-term remediation is considered to mean:
   (1) An immediate repair condition (see §192.933(d)(1)),
   (2) A one-year condition (see §192.933(d)(2)), or
   (3) Other remediation that is required prior to the next scheduled assessment.

(b) If an assessment carried out under §192.931(b) or (c) reveals any corrosion defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE 6.2, "Remaining Life Calculations," and 6.3, "Reassessment Intervals." See §192.931(d).

(c) If the corrosion defect requires immediate remediation, then the operator must reduce pressure consistent with §192.933 until the operator has completed reassessment using one of the assessment techniques allowed in §192.937. If the defect is an external condition, an operator may elect to stop the CDA process and begin a full ECDA assessment by using a second indirect assessment tool. For internal conditions, the operator may perform a full ICDA assessment.

§ 192.933
What actions must an operator take to address integrity issues?
[Effective Date: 07/01/2020]

(a) General requirements. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline’s integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

   (1) Temporary pressure reduction. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see § 192.7); (R–STRENG) (incorporated by reference, see §192.7); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with §192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action.

   (2) Long-term pressure reduction. When a pressure reduction exceeds 365 days, an operator must notify PHMSA under § 192.18 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline.

(b) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see Addendum 5, December 2019
§192.933 (192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) **Special requirements for scheduling remediation.**

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

   (i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, see §192.7), PRCI PR–3–805 (R–STRENG) (incorporated by reference, see §192.7), or an alternative equivalent method of remaining strength calculation.

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

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

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

   (i) A smooth dent located between the 8 o’clock and 4 o’clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

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

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

   (i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o’clock position and the 8 o’clock position (bottom 1/3 of the pipe).

   (ii) A dent located between the 8 o’clock and 4 o’clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

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

1 DISCOVERY OF CONDITION

(a) The operator is expected to define "discovery of condition" in its written integrity management program because that date sets the schedule for evaluation and remediation. Conditions may be discovered as soon as the assessment is completed. Some of these may require immediate action. However, the operator generally has no more than 180 days after completing an assessment to discover a condition that presents a potential threat to the integrity of the pipeline. The operator should document the date each condition was discovered.

(b) Assessment is considered complete after fully executing any one of the following.
   (1) Hydrostatic test.
   (2) Last in-line inspection (ILI) tool run of a scheduled series of tool runs.
   (3) Last direct examination associated with direct assessment.
   (4) Completion of field activities associated with "other technology" for which an operator has provided timely notification as required by §192.921(a)(4).

(c) "Discovery of condition" is dependent on the integrity assessment technique that is used as shown in Table 192.933i.

(d) "Discovery of condition" under §192.933(b) is not necessarily the same as "Discovery" under §191.25. See 3(a) below.

<table>
<thead>
<tr>
<th>Assessment Technique</th>
<th>Discovery of Condition Typically Occurs When:</th>
</tr>
</thead>
<tbody>
<tr>
<td>In-Line Inspection (ILI)</td>
<td>The operator receives a graded or characterized set of indications, or other data, from the inspection device and an analysis indicates a condition exists that could be a threat to pipeline integrity.</td>
</tr>
<tr>
<td>Pressure Testing</td>
<td>A leak that indicates a condition that could be a threat to pipeline integrity is observed or a failure occurs.</td>
</tr>
<tr>
<td>Direct Assessment</td>
<td>Direct examination or analysis of direct examination data indicates a condition that is a threat to pipeline integrity. The analysis should be completed as soon as practical after the direct examination.</td>
</tr>
</tbody>
</table>

2 SCHEDULE FOR EVALUATION AND REMEDIATION

2.1 Immediate repair conditions.

(a) "Immediate repair conditions" are indications that a defect has failed or may be close to failure. These conditions require action within 5 days of discovery. Although §192.933 uses the term "immediate repair condition," a repair is not always required within the 5-day period. A temporary reduction of pressure (see §192.933(a)) will allow the pipeline to continue to operate.

(b) For immediate repair conditions that result from analysis of ILI data, an evaluation of the indication must be conducted within five days of discovery.

(c) For ILI and DA, immediate repair conditions include any of the following.
   (1) An indicated corrosion defect that yields a predicted failure pressure of less than 1.1 times the MAOP.
(2) A dent that has any indication of metal loss, cracking, or a stress riser (see Table 192.933ii).
(3) An indication of stress corrosion cracking.
(4) A metal loss indication affecting a detected longitudinal seam in low-frequency ERW pipe or pipe produced by electric flash welding.
(5) Other indications that might be expected to cause immediate failure or, in the judgment of the operator, require immediate action.
(d) For ECDA, “immediate indications” only become “immediate repair conditions” when direct examination indicates a defect that meets one of the above criteria.

2.2 One-year conditions.
Dents requiring repair within one year are listed in Table 192.933ii.

2.3 Scheduled conditions.
Corrosion indications are required to be analyzed for predicted failure pressure in accordance with ASME B31G, PRCI PR-3-805 (RSTRENG) (see §192.7 for IBR for both), or equivalent method. The failure pressure ($P_f$) is divided by the MAOP to determine a safety factor. The safety factor and operating percent of SMYS determine the maximum time interval for evaluation and remediation. The maximum time interval for responding to scheduled defects may be obtained from ASME B31.8S-2004, Section 7, Figure 4 (see §192.7 for IBR).

2.4 Monitored conditions.
Dents that can be monitored are included in Table 192.933ii.

<table>
<thead>
<tr>
<th>Pipe Size</th>
<th>Dent Location</th>
<th>Description</th>
<th>Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Any</td>
<td>Any</td>
<td>A dent that contains a crack, stress riser, or has metal loss.</td>
<td>Immediate</td>
</tr>
<tr>
<td>Less than 12&quot;</td>
<td>Any</td>
<td>A dent with a depth^1 greater than 0.25 inches that affects a girth weld or longitudinal weld seam, with no engineering analysis.</td>
<td>One year</td>
</tr>
<tr>
<td></td>
<td>Any</td>
<td>A dent with a depth^1 greater than 0.25 inches that affects a girth weld or longitudinal weld seam and engineering analysis demonstrates critical strain levels are not exceeded.</td>
<td>Monitor</td>
</tr>
<tr>
<td>Top 2/3 of pipe</td>
<td>A smooth dent with a depth^1 greater than 0.5 inches, with no engineering analysis.</td>
<td>One year</td>
<td></td>
</tr>
<tr>
<td>Top 2/3 of pipe</td>
<td>A dent with a depth^1 greater than 0.5 inches, and engineering analysis demonstrates critical strain levels are not exceeded.</td>
<td>Monitor</td>
<td></td>
</tr>
<tr>
<td>Bottom 1/3 of pipe</td>
<td>A dent with a depth^1 greater than 0.5 inches.</td>
<td>Monitor</td>
<td></td>
</tr>
</tbody>
</table>

TABLE 192.933ii (Continued)
## REMEDIATION OF DENTS (Continued)

<table>
<thead>
<tr>
<th>Pipe Size</th>
<th>Dent Location</th>
<th>Description</th>
<th>Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equal to or greater than 12&quot;</td>
<td>Any</td>
<td>A dent with a depth(^1) greater than 2% of the pipe diameter that affects a girth weld or longitudinal weld seam, with no engineering analysis.</td>
<td>One year</td>
</tr>
<tr>
<td></td>
<td>Any</td>
<td>A dent with a depth(^1) greater than 2% of the pipe diameter that affects a girth weld or longitudinal weld seam and engineering analysis demonstrates critical strain levels are not exceeded.</td>
<td>Monitor</td>
</tr>
<tr>
<td>Top 2/3 of pipe</td>
<td>A smooth dent with a depth(^1) greater than 6% of the pipe diameter with no engineering analysis.</td>
<td>One year</td>
<td></td>
</tr>
<tr>
<td>Top 2/3 of pipe</td>
<td>A dent with a depth(^1) greater than 6% of the pipe diameter and engineering analysis demonstrates critical strain levels are not exceeded.</td>
<td>Monitor</td>
<td></td>
</tr>
<tr>
<td>Bottom 1/3 of pipe</td>
<td>A dent with a depth(^1) greater than 6% of the pipe diameter.</td>
<td>Monitor</td>
<td></td>
</tr>
</tbody>
</table>

\(^1\) See 2 of the guide material under §192.309 for measuring the depth of a dent.

### TABLE 192.933ii

#### 3 PRESSURE REDUCTION

(a) Conditions that require a reduction in operating pressure may constitute a safety-related condition. See the guide material under §191.25 where the term "Discovery" is referenced for the purpose of reporting safety-related conditions. This is not necessarily the same as "Discovery of condition" under §192.933. See 1(d) above.

(b) If a pressure reduction exceeds 365 days, the operator is required to provide notification (see §192.949). The notification must include the reasons for not remediating within 365 days, and provide technical justification that the pressure reduction is still adequate.

(1) Reasons for the delay in remediation could include preventing a service outage or a delay in obtaining any of the following.
   - (i) Materials.
   - (ii) Permits.
   - (iii) Right-of-way.

(2) Technical justification that the pressure reduction is still adequate should consider one or more of the following.
   - (i) Effect of continued corrosion.
   - (ii) Environmental changes.
   - (iii) Additional pressure cycles.
   - (iv) Class location changes.
   - (v) Validation of the existing pressure reduction.

(c) If the existing pressure reduction is no longer adequate, the operator should do one of the following.

(1) Make further reduction in operating pressure.
(2) Repair or replace the pipe.
(3) Take pipeline out of service.
§ 192.935

What additional preventive and mitigative measures must an operator take?

[Effective Date: 07/01/2020]

(a) General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917.) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) Third party damage and outside force damage.

(1) Third party damage. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum —

(i) Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

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

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) Outside force damage. If an operator determines that outside force (e.g., earth movement, loading, longitudinal, or lateral forces, seismicity of the area, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, relocating the line, or inline inspections with geospatial and deformation tools.

(c) Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors — swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.
(d) **Pipelines operating below 30% SMYS.** An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

1. **Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline;**

2. Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

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

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


**GUIDE MATERIAL**

*This guide material is under review following Amdt. 192-125,*

1 **ADDITIONAL PREVENTIVE AND MITIGATIVE (P&M) MEASURES (§192.935(a) and (c))**

To comply with §192.935, an operator must conduct a risk analysis of all pipelines within HCAs, and determine for each applicable threat on each covered segment whether any of the following (which exceed the requirements of other subparts of Part 192) will prevent pipeline failure or mitigate the consequences of such a failure.

Some activities performed as requirements for additional preventative and mitigative measures may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.616, and 192.620(d)(2).  

(a) **Installation of an automatic shut-off valve (ASV) or a remote control valve (RCV).**

1. To comply with §192.935(c), an operator must consider the following factors in determining if an ASV or RCV would be an efficient means of adding protection in an HCA.

   (i) Swiftness of leak detection. Example: There may be no advantage to installing an ASV or RCV on segments where adequate SCADA or other monitoring methods allow for quick operator response to leakage.

   (ii) Shutdown capabilities in the area. Example: An ASV or RCV might not make shutdown any faster or easier in locations where adequate valving and easy access already exists.

   (iii) Type of gas. Example: An ASV or RCV might mitigate the environmental impact of leakage on a pipeline carrying heavier-than-air gases.

   (iv) Operating pressure. Example: Higher-pressure lines hold a larger volume of gas. An ASV or RCV on such a line may reduce the volume of release and potential for ignition.

   (v) Potential release rate. Example: Installing an ASV or RCV may affect the duration of the potential release rate.

   (vi) Pipeline profile. Example: Heavier-than-air gases can pool in low elevation spots. An ASV or RCV in such locations may allow faster shut off and, therefore, less accumulation of gas.
(vii) Potential for ignition. Example: Areas that have known sources of ignition (e.g., foundries) might benefit from an ASV or RCV.

(viii) Location of nearest response personnel. Example: Locations where operator response is timely may not benefit from the installation of an ASV or RCV.

(2) An operator may also consider the following.

(i) Seasonal weather restrictions that can impede access.

(ii) Depth of pipe as it relates to access for squeeze-off.

(iii) River crossings or other geographical features that affect access for maintenance or response.

(iv) Proximity of the HCA to existing valves.

(v) Population density.

(vi) Wide pressure fluctuations due to normal operating conditions (e.g., power plant locations).

(vii) Maintenance, reliability, and cost-benefit issues.

(b) Installation of computerized monitoring and leak detection systems.

An operator may consider the following, which could provide earlier leak or pipeline rupture detection.

(1) Increasing the locations monitored by SCADA.

(2) Automating data gathering from other monitoring devices such as pressure transmitters.

(c) Replacing pipe with that of heavier-wall thickness, which is more resistant to damage from external forces.

(d) Providing additional training on response procedures.

An operator may consider the following.

(1) Increasing the frequency of emergency response training.

(2) Conducting tabletop or field drills.

(3) Hiring a third party with expertise in emergency response to conduct training.

(4) Attending emergency response training offered by industry associations.

(e) Conducting drills with local emergency responders.

The operator may consider the following.

(1) Including the drill as part of liaison meetings with emergency responders.

(2) Working with local multi-agency, emergency coordination groups.

(3) Incorporating the drill into local fire or police academy curriculum.

(f) Implementing additional inspection and maintenance programs.

The operator may consider the following.

(1) Increasing leak survey frequencies.

(2) Increasing patrol frequencies.

(3) Using procedures with more stringent criteria than required by the Regulations.

(4) Increasing facility inspection frequencies.

2 THIRD-PARTY DAMAGE (§192.935(b)(1))

To comply with §192.935(b)(1) for the specific threat of third-party damage, an operator must do the following.

(a) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.

(1) Locating the pipeline.

(2) Marking the pipeline.

(3) Directly supervising known excavation work. A qualification for this activity might include the following.

(i) Recognition of line-locate markings.

(ii) Knowledge of one-call requirements.

(iii) Knowledge of operator’s applicable procedures, including emergency response.

(iv) Understanding the risks of various excavation methods.

(4) Other activities that could adversely affect the integrity of the pipeline.
5 PLASTIC TRANSMISSION LINES (§192.935(e))

Plastic transmission lines have additional requirements as follows.

(a) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
   (1) Locating the pipeline.
   (2) Marking the pipeline.
   (3) Directly supervising known excavation work. A qualification for this activity might include the following.
      (i) Recognition of line-locate markings.
      (ii) Knowledge of one-call requirements.
      (iii) Knowledge of operator’s applicable procedures, including emergency response.
      (iv) Understanding the risks of various excavation methods.
   (4) Other activities that could adversely affect the integrity of the pipeline.

(b) Participate in a one-call program wherever there are covered segments.

(c) Monitor excavations on covered segments. An operator may want to consider the following.
   (1) Mapping HCAs so field personnel can easily recognize when they are in an area that requires monitoring.
   (2) Creating a business process that alerts the appropriate departments of pending excavations.
   (3) Working with the local One-Call Center to notify excavators and operators when monitoring is required.
   (4) Training line locators to notify appropriate personnel when they know work will take place in an HCA.
   (5) Documenting excavation monitoring by using one or more of the following.
      (i) Time card accounting.
      (ii) Special forms.
      (iii) Time-stamped electronic data.
      (iv) Maps.

(d) When there is physical evidence of an encroachment on a covered segment that the operator did not monitor, excavate the area to determine if any damage has occurred. Examples of how to identify an encroachment include the following.
   (1) New pavement patches.
   (2) Heavy equipment on site.
   (3) Disturbed earth.
   (4) New structures requiring excavation (e.g., fence posts, telephone poles, buildings, slabs).
   (5) Exposed pipe.
   (6) New landscaping.
   (7) One-call documentation.

(e) See Table 192.935i.
## ADDITIONAL P&M MEASURES FOR TRANSMISSION PIPELINES OPERATING BELOW 30 PERCENT SMYS AND PLASTIC TRANSMISSION LINES

<table>
<thead>
<tr>
<th>Location</th>
<th>General Requirements</th>
<th>Use Qualified Personnel</th>
<th>Participate in one-call</th>
<th>Monitor Excavations or Additional Patrol</th>
<th>Additional Leak Survey</th>
</tr>
</thead>
<tbody>
<tr>
<td>Class 1 &amp; 2 in HCA</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Class 1 &amp; 2 outside HCA</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Class 3 &amp; 4 in HCA</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Class 3 &amp; 4 outside HCA</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Plastic Transmission</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X (monitor only) ¹</td>
<td></td>
</tr>
</tbody>
</table>

¹ The option of patrolling is not available for plastic transmission lines.

**TABLE 192.935i**
§ 192.937
What is a continual process of evaluation and assessment to maintain a pipeline’s integrity? [Effective Date: 07/01/2020]

(a) General. After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in § 192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under § 192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in § 192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) Evaluation. An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in § 192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§ 192.917), and decisions about remediation (§ 192.933) and additional preventive and mitigative actions (§ 192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) Assessment methods. In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by applying one or more of the following methods for each threat to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified on the covered segment (see § 192.917).

(1) Internal inspection tools. When performing an assessment using an in-line inspection tool, an operator must comply with the following requirements:
   (i) Perform the in-line inspection in accordance with § 192.493;
   (ii) Select a tool or combination of tools capable of detecting the threats to which the pipeline segment is susceptible such as corrosion, deformation and mechanical damage (e.g. dents, gouges and grooves), material cracking and crack-like defects (e.g. stress corrosion cracking, selective seam weld corrosion, environmentally assisted cracking, and girth weld cracks), hard spots with cracking, and any other threats to which the covered segment is susceptible; and
   (iii) Analyze and account for uncertainties in reported results (e.g., tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying actual tool performance) in identifying and characterizing anomalies.

(2) Pressure test conducted in accordance with subpart J of this part. The use of pressure testing is appropriate for threats such as: internal corrosion; external corrosion and other environmentally assisted corrosion mechanisms; manufacturing and related defects threats, including defective pipe and pipe seams; stress corrosion cracking; selective seam weld corrosion; dents; and other forms of mechanical damage. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S (incorporated by reference, see § 192.7) to justify an extended reassessment interval in accordance with §192.939.

(3) Spike hydrostatic pressure test in accordance with § 192.506. The use of spike hydrostatic pressure testing is appropriate for time-dependent threats such as: stress corrosion cracking; selective seam weld corrosion; manufacturing and related defects,
including defective pipe and pipe seams; and other forms of defect or damage involving cracks or crack-like defects;

(4) Excavation and in situ direct examination by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, or magnetic particle inspection (MPI);

(5) Guided wave ultrasonic testing (GWUT) as described in Appendix F. The use of GWUT is appropriate for internal and external pipe wall loss;

(6) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. The use of direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking is allowed only if appropriate for the threat and pipeline segment being assessed. Use of direct assessment for threats other than the threat for which the direct assessment method is suitable is not allowed. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with the applicable requirements specified in §§ 192.925, 192.927 or 192.929;

(7) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe for each of the threats to which the pipeline is susceptible. An operator must notify PHMSA in advance of using the other technology in accordance with § 192.18; or

(8) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than 7 calendar years. An operator using this reassessment method must comply with §192.931.

(d) MAOP reconfirmation assessments. An integrity assessment conducted in accordance with the requirements of § 192.624(c) may be used as a reassessment under this section.


GUIDE MATERIAL

This guide material is under review following Amdt. 192-125.

1 GENERAL

See the guide material under §192.939 for reassessment intervals.

2 EVALUATION FOR COVERED SEGMENTS

One of the goals of periodic evaluation is to determine what is changing and what actions are needed to maintain safe operations. Periodic evaluations are based on integrating information, identifying changes to pipeline threats, and updating risk analyses. This evaluation is intended to support the identification of changes needed to assessment frequencies, assessment types, and preventive and mitigative (P&M) measures.

2.1 Frequency.

When determining the frequency, the operator should consider the following.

(a) The number and types of changes that are occurring. For example, if there are no changes to HCAs, MAOPs, or personnel, a longer interval may be appropriate.

(b) For pipe subject to low stress reassessment, the requirement to evaluate external corrosion data for:

(1) Cathodically protected lines at least once every 7 years (§192.941(b)(1)), or

(2) Unprotected pipe at least once every 18 months (§192.941(b)(2)).

(c) For pipe subject to low stress reassessment, the requirement to evaluate internal corrosion data at
least once every 7 years (§192.941(c)(3)).
(d) The evaluation intervals should not exceed the assessment intervals listed in ASME B31.8S-2004, Section 5, Table 3 (see §192.7 for IBR).
(e) Items that might trigger an evaluation (e.g., incidents, new data) before the scheduled evaluation.

2.2 Data integration.
Use information collected through assessment, remediation, and P&M measures to update records where default values were used, or that have been determined to be inaccurate or incomplete.

2.3 Threat identification.
Use information collected through assessment, remediation, and P&M measures to identify new threats or to evaluate the severity of existing threats. Additional changes to threats may be identified through the evaluation of the following.
(a) Failures.
(b) Incidents.
(c) Abnormal operations.
(d) Lessons learned.
(e) Performance metrics.

2.4 Risk analysis.
(a) Use information collected through assessment, remediation, and P&M measures to determine if the risk ranking is consistent with the results.
(b) Use information collected through data integration, assessment, remediation, and P&M measures to update the risk model.
(c) Changes to segments included in risk assessment may be identified through the evaluation of the following.
   (1) System modifications.
   (2) HCA changes.
   (3) O&M activities.
   (4) Operational changes.
   (5) Environmental changes.

2.5 Subsequent actions driven by periodic evaluation.
(a) Identify changes required to assessment intervals.
(b) Confirm that assessment methods are applicable for the identified threats.
(c) If current methods are not effective for current threats, determine correct assessment methods and reassess applicable segments.
(d) Determine the effectiveness of current P&M measures.
(e) Determine the need for changes to existing P&M measures or implementation of additional measures.
(f) If an operator changes the criteria for grading ILI anomalies, the operator should review the impact of the changes on anomalies discovered during the prior assessments.
(g) If an operator changes ECDA or ICDA criteria for classifying indications, or for calculating the remaining life, the operator should review the impact of the changes on the results from the prior assessment.
(h) Evaluate the potential requirement for assessment and remediation of a threat on other pipeline segments as follows.
   (1) Similar pipeline segments when corrosion or seam issues are identified as a threat in a covered segment.
   (2) Similar covered segments when any threats are identified outside a covered segment.

3 ASSESSMENT METHODS
(a) For reassessment methods, see the guide material under §192.921.
(b) For CDA, see guide material under §192.931.
§192.939
What are the required reassessment intervals?

[Effective Date: 07/01/2020]

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

(a) Pipelines operating at or above 30% SMYS. An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS, in accordance with §192.18, with sufficient justification of the need for the extension. If an operator establishes a reassessment interval that is greater than 7 calendar years, the operator must, within the 7-calendar-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) Pressure test or internal inspection or other equivalent technology. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by —
   (i) Basing the interval on the identified threats for the covered segment (see §192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §192.917; or
   (ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, see §192.7), section 5, Table 3.

(2) External Corrosion Direct Assessment. An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, see §192.7).

(3) Internal Corrosion or SCC Direct Assessment. An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.
   (i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;
   (ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and
   (iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

(b) Pipelines Operating Below 30% SMYS. An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is 7 calendar years. Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to OPS in accordance with §192.18. The notice must include sufficient justification of the need for the extension. An operator must establish reassessment by at least one of the following —

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than 7 calendar years, an operator must conduct by the seventh calendar year of the interval either a confirmatory direct assessment in accordance with §192.931, or
a low stress reassessment in accordance with §192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

<table>
<thead>
<tr>
<th>Assessment Method</th>
<th>Pipeline operating at or above 50% SMYS</th>
<th>Pipeline operating at or above 30% SMYS, up to 50% SMYS</th>
<th>Pipeline operating below 30% SMYS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Internal Inspection Tool, Pressure Test or Direct Assessment</td>
<td>10 years(*)</td>
<td>15 years(*)</td>
<td>20 years(**)</td>
</tr>
<tr>
<td>Confirmatory Direct Assessment</td>
<td>7 years</td>
<td>7 years</td>
<td>7 years</td>
</tr>
<tr>
<td>Low Stress Reassessment</td>
<td>Not Applicable</td>
<td>Not Applicable</td>
<td>7 years + ongoing actions specified in §192.941</td>
</tr>
</tbody>
</table>

(*) A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.

(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

GUIDE MATERIAL

This guide material is under review following Amdt. 192-125.

1 GENERAL

The factors that determine the reassessment interval include the following.
(a) Operating stress levels.
(b) Type of prior assessment.
(c) Analysis of defects from prior assessment.
(d) Prescriptive or performance based programs.
(e) Requirement for a 7-year reassessment interval.
3 WAIVER APPLICATIONS

(a) Applications for a waiver (special permit) can be made as follows.
   (1) From an interstate pipeline operator to PHMSA-OPS in accordance with 49 USC 60118(c) - Waivers approved by Secretary.
      Note: 49 USC 60118 uses the term “waiver” and has not adopted the alternate term “special permit.”
   (2) From an intrastate pipeline operator to its state agency in accordance with 49 USC 60118(d) - Waivers approved by state authorities. If the state does not have a current pipeline program certification, the operator applies to PHMSA-OPS in accordance with 49 USC 60118(c).

(b) The application should include the following.
   (1) Information about the pipeline segment and HCA involved.
   (2) Supporting documentation.
   (3) The date when an assessment will take place.

§192.945
What methods must an operator use to measure program effectiveness?  
[Effective Date: 01/01/11]

(a) General. An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, see §192.7 of this part), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by §191.17 of this subchapter.

(b) External corrosion direct assessment. In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.


GUIDE MATERIAL

1 REPORTING MEASURES

The required reporting measures are provided in the instructions for Form PHMSA F7100.2-1 available from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.

2 ADDITIONAL PERFORMANCE MEASURES

Operators are required to maintain the threat-specific performance measures identified in ASME B31.8S-2004, Table 9 (see §192.7 for IBR). Operators are not required to report these measures to PHMSA-OPS, but must make the records available for inspection.

3 EXTERNAL CORROSION DIRECT ASSESSMENT

Operators using ECDA are required to define performance measures. Guidance can be found in
4 PROGRAM EFFECTIVENESS EVALUATION


§192.947
What records must an operator keep?

[Effective Date: 04/06/04]

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with §192.907;

(b) Documents supporting the threat identification and risk assessment in accordance with §192.917;

(c) A written baseline assessment plan in accordance with §192.919;

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with §192.915;

(f) Schedule required by §192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.

(g) Documents to carry out the requirements in §§192.923 through 192.929 for a direct assessment plan;

(h) Documents to carry out the requirements in §192.931 for confirmatory direct assessment;

(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.


GUIDE MATERIAL

1 PROGRAM AND PROCESS RECORDS

1.1 General.

Operators should maintain, for the useful life of the pipeline, documents to support decisions, analyses, and processes related to development, implementation, and evaluation of the integrity management program regardless of any record-retention requirements within other subparts. See Guide Material Appendix G-192-17 for a summary of records required by Subpart O. Records may be kept in various formats and media including the following.

(a) Paper records.

(b) Electronic records (e.g., emails, databases, spreadsheets, documents).

(c) Audio recordings.
1.2 **Revisions to the Integrity Management Program (IMP).**
Copies of revisions to the integrity management program should be kept for documentation. If changes are made to the program as a result of revisions to standards or regulations, copies of the historical and current versions of the standards should be kept. Note that significant changes to the operator’s program require notification to PHMSA-OPS or state pipeline safety authorities. See guide material under §192.949.

1.3 **Threat identification and risk assessment.**
Documentation for threat identification and risk assessment might include the following.
(a) Description of the process used for risk analysis.
(b) History of risk analysis results.
(c) Minutes from subject matter expert meetings.
(d) List of threats.

1.4 **Baseline assessment plans.**
Operators should retain and record the technical basis for changes to their baseline assessment plans. Operators should retain adequate documentation to illustrate how their plans have changed and the technical justification for those changes. Documentation might include historical and current records as follows.
(a) Schedules.
(b) Threat lists and assessment methods.
(c) Direct assessment plans.
(d) Environmental and safety procedures.

2 **TRAINING AND QUALIFICATION OF PERSONNEL**

Documentation for employee training and qualification might include the following.
(a) Training curriculum.
(b) Training outlines.
(c) Training schedules.
(d) Sample tests.
(e) Employee training records.

3 **ONGOING ACTIVITY**

3.1 **Evaluation and remediation.**
Documentation for the evaluation and remediation schedule might include the following.
(a) List of conditions found.
(b) Repairs, monitoring, replacements, or pressure reductions performed.
(c) Priority of conditions.
(d) Scheduled evaluation or remediation date.
(e) Written justification for assigning priority.

3.2 **Direct and confirmatory assessment.**
Documentation for direct and confirmatory assessments might include the following.
(a) Procedures for assessment methods.
(b) Criteria for evaluating assessment results.
(c) Tool selection criteria.
(d) Forms or other documentation of field data.

4 **REGULATORY CORRESPONDENCE**

Documentation of correspondence with PHMSA-OPS and state pipeline safety agencies relating to integrity management issues should be retained.
§192.949 [Removed and Reserved]


GUIDE MATERIAL

This guide material is under review following Amdt. 192-125.

1 NOTIFICATION INFORMATION

See the following sections for information regarding specific notification requirements.

(a) Section 192.909, when the operator makes substantial changes to the integrity management program. Notifications include the following information.
   (1) Operator name and ID.
   (2) Description and reason for the program or schedule change.

(b) Sections 192.921 and 192.937, when the operator makes use of technologies for assessment other than internal inspection tools, pressure tests, or direct assessment. Notifications include the following information.
   (1) Operator name and ID.
   (2) Description and rationale for new technology.
   (3) Where the technology will be used.
   (4) Procedures for applying the technology.
   (5) Procedures for qualifying persons performing the assessment and analyzing the results.

(c) Section 192.927, when ICDA is used to assess a covered segment with an electrolyte present in the gas stream. Notifications include the following information.
   (1) Operator name and ID.
   (2) Description of system.
   (3) Justification for using ICDA.
   (4) How public safety will be maintained.

(d) Section 192.933(a)(1), when the operator cannot meet the schedule and cannot provide safety through temporary pressure reduction. Notifications include the following information.
   (1) Operator name and ID.
   (2) Reason why the schedule cannot be met or temporary pressure reduction cannot be implemented.
   (3) How public safety will be maintained.

(e) Section 192.933(a)(2), when a pressure reduction exceeds 365 days. Notifications include the following information.
   (1) Operator name and ID.
   (2) Reason for remediation delays.
   (3) Technical justification that pressure reduction is sufficient for maintaining public safety.
Appendix F to Part 192

Criteria for Conducting Integrity Assessments Using Guided Wave Ultrasonic Testing (GWUT)

[Effective Date: 07/01/2020]

This appendix defines criteria which must be properly implemented for use of guided wave ultrasonic testing (GWUT) as an integrity assessment method. Any application of GWUT that does not conform to these criteria is considered “other technology” as described by §§ 192.710(c)(7), 192.921(a)(7), and 192.937(c)(7), for which OPS must be notified 90 days prior to use in accordance with §§ 192.921(a)(7) or 192.937(c)(7). GWUT in the “Go-No Go” mode means that all indications (wall loss anomalies) above the testing threshold (a maximum of 5% of cross sectional area (CSA) sensitivity) be directly examined, in-line tool inspected, pressure tested, or replaced prior to completing the integrity assessment on the carrier pipe.

I. Equipment and Software: Generation. The equipment and the computer software used are critical to the success of the inspection. Computer software for the inspection equipment must be reviewed and updated, as required, on an annual basis, with intervals not to exceed 15 months, to support sensors, enhance functionality, and resolve any technical or operational issues identified.

II. Inspection Range. The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). A signal that has an amplitude that is at least twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as surface roughness, coating, coating condition, associated pipe fittings (T’s, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general, the inspection range can approach 60 to 100 feet for a 5% CSA, depending on field conditions.

III. Complete Pipe Inspection. To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double-ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature from both sides and show an approximate 5% distance overlap.

IV. Sensitivity. The detection sensitivity threshold determines the ability to identify a cross sectional change. The maximum threshold sensitivity cannot be greater than 5% of the cross sectional area (CSA).

The locations and estimated CSA of all metal loss features in excess of the detection threshold must be determined and documented.

All defect indications in the “Go-No Go” mode above the 5% testing threshold must be directly examined, in-line inspected, pressure tested, or replaced prior to completing the integrity assessment.

V. Wave Frequency. Because a single wave frequency may not detect certain defects, a minimum of three frequencies must be run for each inspection to determine the best frequency for characterizing indications. The frequencies used for the inspections must be documented and must be in the range specified by the manufacturer of the equipment.

VI. Signal or Wave Type: Torsional and Longitudinal. Both torsional and longitudinal waves must be used and use must be documented.

VII. Distance Amplitude Correction (DAC) Curve and Weld Calibration. The distance amplitude correction curve accounts for coating, pipe diameter, pipe wall and environmental conditions at the assessment location. The DAC curve must be set for each inspection as part of establishing the effective range of a GWUT inspection. DAC curves provide a means for evaluating the cross-sectional area change of reflections at various distances in the test range by assessing
signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

VIII. **Dead Zone.** The dead zone is the area adjacent to the collar in which the transmitted signal blinds the received signal, making it impossible to obtain reliable results. Because the entire line must be inspected, inspection procedures must account for the dead zone by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the dead zone is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

IX. **Near Field Effects.** The near field is the region beyond the dead zone where the receiving amplifiers are increasing in power, before the wave is properly established. Because the entire line must be inspected, inspection procedures must account for the near field by requiring the movement of the collar for additional inspections. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface. The length of the dead zone and the near field for each inspection must be documented.

X. **Coating Type.** Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the pipe, then another type of assessment method must be utilized.

XI. **End Seal.** When assessing cased carrier pipe with GWUT, operators must remove the end seal from the casing at each GWUT test location to facilitate visual inspection. Operators must remove debris and water from the casing at the end seals. Any corrosion material observed must be removed, collected and reviewed by the operator’s corrosion technician. The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range.

XII. **Weld Calibration to set DAC Curve.** Accessible welds, along or outside the pipeline segment to be inspected, must be used to set the DAC curve. A weld or welds in the access hole (secondary area) may be used if welds along the pipeline segment are not accessible. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. There must not be a weld between the transducer collar and the calibration weld. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual weld cap height is different from the assumed weld cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Alternative means of calibration can be used if justified by a documented engineering analysis and evaluation.

XIII. **Validation of Operator Training.** Pipeline operators must require all guided wave service providers to have equipment-specific training and experience for all GWUT Equipment Operators which includes training for:

A. equipment operation,
B. field data collection, and
C. data interpretation on cased and buried pipe.

Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, may operate the equipment. A senior-level GWUT equipment operator with pipeline specific experience must provide onsite oversight of the inspection and approve the final reports. A senior-level GWUT equipment operator must have additional training and experience, including training specific to cased and buried pipe, with a quality control program which that conforms to Section 12 of ASME B31.8S (for availability, see § 192.7).

XIV. **Training and Experience Minimums for Senior Level GWUT Equipment Operators:**

- Equipment Manufacturer’s minimum qualification for equipment operation and data
collection with specific endorsements for casings and buried pipe

- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer’s minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe.

XV. Equipment: traceable from vendor to inspection company. An operator must maintain documentation of the version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., in the report.

XVI. Calibration Onsite. The GWUT equipment must be calibrated for performance in accordance with the manufacturer’s requirements and specifications, including the frequency of calibrations. A diagnostic check and system check must be performed on-site each time the equipment is relocated to a different casing or pipeline segment. If on-site diagnostics show a discrepancy with the manufacturer’s requirements and specifications, testing must cease until the equipment can be restored to manufacturer’s specifications.

XVII. Use on Shorted Casings (direct or electrolytic). GWUT may not be used to assess shorted casings. GWUT operators must have operations and maintenance procedures (see § 192.605) to address the effect of shorted casings on the GWUT signal. The equipment operator must clear any evidence of interference, other than some slight dampening of the GWUT signal from the shorted casing, according to their operating and maintenance procedures. All shorted casings found while conducting GWUT inspections must be addressed by the operator’s standard operating procedures.

XVIII. Direct examination of all indications above the detection sensitivity threshold. The use of GWUT in the “Go-No Go” mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe or other GWUT application. If this cannot be accomplished, then alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

XIV. Timing of direct examination of all indications above the detection sensitivity threshold. Operators must either replace or conduct direct examinations of all indications identified above the detection sensitivity threshold according to the table below. Operators must conduct leak surveys and reduce operating pressure as specified until the pipe is replaced or direct examinations are completed.

<table>
<thead>
<tr>
<th>Required Response to GWUT Indications</th>
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<tr>
<td>GWUT Criterion</td>
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<td>Over the detection sensitivity threshold (maximum of 5% CSA)</td>
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[Issued by Amdt. 192-125, Oct. 01, 2019]
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<th>1.14 OTHER DOCUMENTS</th>
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<tr>
<td>AGA X69804</td>
<td>Historical Collection of Natural Gas Pipeline Safety Regulations [Available from GPTC Secretary at AGA.]</td>
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<tr>
<td>AGA XK1801</td>
<td>Purging Manual</td>
<td>§192.629 §192.727</td>
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<td>AGA XL0702</td>
<td>Distribution Pipe: Repair and Replacement Decision Manual</td>
<td>§192.465 §192.703 GMA G-192-18</td>
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<td>AGA XL1001</td>
<td>Classification of Locations for Electrical Installations in Gas Utility Areas</td>
<td>§192.163</td>
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<td>AGA XQ0005</td>
<td>Odorization Manual</td>
<td>§192.625</td>
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<tr>
<td>API Guidance Document HF1</td>
<td>Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines</td>
<td>§192.12</td>
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<td>API Guidance Document HF2</td>
<td>Water Management Associated with Hydraulic Fracturing</td>
<td>§192.12</td>
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<td>API RP 5A3</td>
<td>Recommended Practice on Thread Compounds for Casing, Tubing, and Drill Stem Elements</td>
<td>§192.12</td>
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<td>API RP 5A5</td>
<td>Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe</td>
<td>§192.12</td>
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<td>API RP 5B1</td>
<td>Gauging and Inspection of Casing, Tubing and Line Pipe Threads</td>
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<td>API RP 5C1</td>
<td>Recommended Practice for Care and Use of Casing and Tubing</td>
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<td>API RP 10D-2</td>
<td>Recommended Practice for Centralizer Placement and Stop-collar Testing</td>
<td>§192.12</td>
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<td>API RP 10F</td>
<td>Recommended Practice for Performance Testing of Cementing Float Equipment</td>
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<td>API RP 13D</td>
<td>Rheology and Hydraulics of Oil-well Drilling Fluids</td>
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<td>API RP 14E</td>
<td>Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems</td>
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<tr>
<td>Standard</td>
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<td>Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide</td>
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<td>API RP 51R</td>
<td>Environmental Protection for Onshore Oil and Gas Production Operations and Leases</td>
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<td>Contractor Safety Management for Oil and Gas Drilling and Production Operations</td>
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<td>Design and Operation of Solution-mined Salt Caverns Used for Liquid Hydrocarbon Storage</td>
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<td>API RP 1117</td>
<td>Movement of In-Service Pipelines</td>
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<td>Managing System Integrity of Gas Pipelines</td>
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<td>ASME CRTD Vol. 57</td>
<td>Determining the Yield Strength of In-Service Pipe</td>
<td>§192.107</td>
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<td>Applications Guide for Determining the Yield Strength of In-Service Pipe by Hardness Evaluation</td>
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<td>Standard Practice for Classification of Soils for Engineering Purposes (Unified Soil Classification System)</td>
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<td>Standard Practice for Underground Installation of Thermoplastic Pressure Piping</td>
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<td>Standard Practice for Minimum Requirements for Agencies Engaged in Testing and/or Inspection of Soil and Rock as Used in Engineering Design and Construction</td>
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<td>ASTM D4543</td>
<td>Standard Practices for Preparing Rock Core as Cylindrical Test Specimens and Verifying Conformance to Dimensional and Shape Tolerances</td>
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<td>ASTM D4645</td>
<td>Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method</td>
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<td>Standard Test Methods for Natural Gas Odor Intensity</td>
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<td>Test Method for Surface Burning Characteristics of Building Materials</td>
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<td>AWS A3.0</td>
<td>Standard Welding Terms and Definitions</td>
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<td>One Call Systems International (OCSI) Resource Guide</td>
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<td>Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways</td>
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<td>Executive Summary: Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways</td>
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<td>GRI-95/0171</td>
<td>State-of-the-Art Review and Analysis of Guided Drilling Systems</td>
<td>GMA G-192-15B</td>
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<td>GRI-96/0368</td>
<td>Guidelines for the Application of Guided Horizontal Drilling to Install Gas Distribution Pipe</td>
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<td>IAPMO</td>
<td>Uniform Plumbing Code</td>
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<td>ISO 31000</td>
<td>Risk Management – Guidelines</td>
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<td>ISO 55000</td>
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<td>NCB</td>
<td>Subsidence Engineers’ Handbook, National Coal Board Mining Department (U.K.), 1975</td>
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<td>NFPA 10</td>
<td>Portable Fire Extinguishers</td>
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<td>PRCI L22279</td>
<td>Further Studies of Two Methods for Repairing Defects in Line Pipe</td>
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<td>PRCI L51406</td>
<td>Pipeline Response to Buried Explosive Detonations</td>
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<td>PRCI L51574</td>
<td>Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement</td>
<td>GMA G-192-13</td>
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<tr>
<td>PRCI L51717</td>
<td>Pipeline In-Service Relocation Engineering Manual</td>
<td>§192.703</td>
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<td>PRCI L51725</td>
<td>Drilling Fluids in Pipeline Installation by Horizontal Directional Drilling-A Practical Applications Manual</td>
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<td>PRCI L51740</td>
<td>Evaluation of the Structural Integrity of Cold Field-Bent Pipe</td>
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<td>Pipeline Repair Manual</td>
<td>§192.613</td>
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<td>PRCI PC-PISCES</td>
<td>Personal Computer - Pipeline Soil Crossing Evaluation System (PC-PISCES), Version 2.0 (Related to API RP 1102)</td>
<td>GMA G-192-15</td>
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<td>PRCI PR-218-9307</td>
<td>Pipeline Repair Manual</td>
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<td>UL 723</td>
<td>Test for Surface Burning Characteristics of Building Materials</td>
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**Note:** NTSB Reports are available at www.ntsb.gov/investigations/AccidentReports/Pages/pipeline.aspx
OPS Advisory Bulletins and Alert Notices are accessible as follows.
- PHMSA-OPS website at www.phmsa.dot.gov/regulations-fr/notices

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<td>NTSB Report SIR-98-01</td>
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<td>OPS ADB-86-02</td>
<td>Advisory Bulletin – Plastic Piping, Mechanical Coupling (Feb. 26, 1986; see document at PHMSA-OPS website)</td>
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<td>Advisory Bulletin – Susceptibility of Certain Polyethylene Pipe Manufactured by Century Utility Products, Inc. to Premature Failure Due to Brittle-Like Cracking (64 FR 12211, Mar. 11, 1999)</td>
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<td><strong>OPS TTO No. 8</strong></td>
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<td><strong>PHMSA-OPS</strong></td>
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<td><strong>Gas Integrity Management Protocols</strong></td>
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<td><strong>Guidance Manual for Operators of LP Gas Systems</strong></td>
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<tr>
<td><strong>Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs</strong></td>
</tr>
<tr>
<td><strong>Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics</strong></td>
</tr>
<tr>
<td><strong>&quot;Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Gas Pipelines&quot;</strong></td>
</tr>
<tr>
<td><strong>Notice – Development of Class Location Change Waiver Criteria (69 FR 38948, June 29, 2004)</strong></td>
</tr>
<tr>
<td><strong>Operator Qualification Guidance Manual for Operators of LP Gas Systems</strong></td>
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<tr>
<td><strong>Operator Qualification Guide for Small Distribution Systems</strong></td>
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Table Continued
# TECHNICAL PAPERS & PUBLICATIONS

## 3.1 EMERGENCY RELATED

(Reserved)

## 3.2 CORROSION RELATED

<table>
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<tr>
<th>Title</th>
<th>Authors</th>
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<th>Price</th>
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<tbody>
<tr>
<td>&quot;Evaluation of Chemical Treatments in Natural Gas System vs. MIC and Other Forms of Internal Corrosion Using Carbon Steel Coupons,&quot; Timothy Zintel, Derek Kostuck, and Bruce Cookingham</td>
<td>Paper # 03574 presented at CORROSION/03 San Diego, CA</td>
<td>§192.475</td>
<td></td>
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<tr>
<td>&quot;Field Use Proves Program for Managing Internal Corrosion in Wet-Gas Systems,&quot; Richard Eckert and Bruce Cookingham</td>
<td>Oil &amp; Gas Journal, January 21, 2002</td>
<td>§192.475</td>
<td></td>
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<tr>
<td>&quot;Internal Corrosion Direct Assessment,&quot; Oliver Moghissi, Bruce Cookingham, Lee Norris, and Phil Dusek</td>
<td>Paper # 02087 presented at CORROSION/02 Denver, CO</td>
<td>§192.475</td>
<td></td>
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<tr>
<td>&quot;Internal Corrosion Direct Assessment of Gas Transmission Pipeline – Application,&quot; Oliver Moghissi, Laurie Perry, Bruce Cookingham, and Narasi Sridhar</td>
<td>Paper # 03204 presented at CORROSION/03 San Diego, CA</td>
<td>§192.475</td>
<td></td>
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## 3.3 PLASTIC RELATED

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<tr>
<td>Plastic Pipe Database Committee (PPDC) reports, <a href="http://www.agag.org/Kc/OperationsEngineering/ppdc/Status%20Reports/Pages/default.aspx">www.agag.org/Kc/OperationsEngineering/ppdc/Status%20Reports/Pages/default.aspx</a></td>
<td></td>
<td>§192.917</td>
</tr>
<tr>
<td>&quot;Polyamide 11 Liners Withstand Hydrocarbons, High Temperature,&quot; A. Berry, Pipeline &amp; Gas Journal, December 1998, p. 81</td>
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### 3.4 UNCASED PIPE AND DIRECTIONAL DRILLING RELATED

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<th>Reference</th>
<th>Source</th>
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<tr>
<td>&quot;Considerations for the Installation of Polyethylene Water Pipe by ‘Horizontal Directional Drilling,’ Larry Petroff, Performance Pipe, presented at Annual Conference and Exposition of AWWA, 2006</td>
<td></td>
<td>GMA-192-15B</td>
</tr>
<tr>
<td>&quot;Guidelines For A Successful Directional Crossing Bid Package,&quot; Directional Crossing Contractors Association, 1995</td>
<td></td>
<td>GMA-192-15A</td>
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### 3.5 SAFETY AND INTEGRITY MANAGEMENT RELATED

<table>
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<th>Reference</th>
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<th>§192.917</th>
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<tr>
<td>&quot;Guideline for Assessing the Performance of Oil and Natural Gas Pipeline Systems in Natural Hazard and Human Threat Events,&quot; American Lifelines Alliance.</td>
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3.5 SAFETY AND INTEGRITY MANAGEMENT RELATED (Continued)

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<td>&quot;Integrity Characteristics of Vintage Pipelines,&quot; INGAA</td>
<td>§192.917</td>
<td></td>
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3.6 GENERAL

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<th>Section</th>
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4 PUBLISHING ORGANIZATIONS

The specifications, codes, standards, and other documents listed in Sections 1 and 2 are published by the following organizations:

AGA American Gas Association
400 North Capitol Street, NW, 4th Floor
Washington, DC 20001
Phone: 202.824.7000
Fax: 734.780.8000
On line: www.ag.org/GPTC

ANSI American National Standards Institute
25 West 43rd Street, 4th Floor
New York, NY 10036
Phone: 212.642.4900
Fax: 212.398.0023
On line: wwwansi.org

API American Petroleum Institute
1220 L Street, NW
Washington, D.C. 20005-4070
Phone: 202.682.8000
Fax: 202.682.8154
On line: wwwapi.org

AREMA American Railway Engineering and Maintenance-of-Way Association
4501 Forbes Blvd, Suite 130
Lanham, MD 20706
Phone: 301.459.3200

Addendum 5, December 2019
Fax: 301.459.8077
On line: www.arema.org

ASCE  The American Society of Civil Engineers
1801 Alexander Bell Drive
Reston, VA 20191-4400
Phone: 800.548.2723
Fax: 703.295.6333
On line: www.asce.org

ASME  The American Society of Mechanical Engineers International
New Jersey Service Center
150 Clove Road
Little Falls, NJ 07424-2100
Phone: 800.843.2763
Fax: 973.882.1717
On line: www.asme.org

ASNT  American Society for Nondestructive Testing
P.O. Box 28518
1711 Arlingate Lane
Columbus, OH 43228-0518
Phone: 800.222.2768
Fax: 614.274.6899
On line: www.asnt.org

ASTM  ASTM International (formerly American Society for Testing and Materials)
100 Barr Harbor Drive
West Conshohocken, PA 19428-2959
Phone: 877.909.2786
Fax: 610.832.9555
On line: www.astm.org

AWS  American Welding Society
8669 NW 36 Street, #130
Miami, FL 33166-6672
Phone: 305.443.9353     800.443.9353
Fax: 305.443.5951
On line: www.aws.org

AWWA  American Water Works Association
6666 W. Quincy Avenue
Denver, CO 80235
Phone: 303.794.7711     800.926.7337
Fax: 303.347.0804
On line: www.awwa.org

BSEE  Bureau of Safety and Environmental Enforcement
1849 C Street, NW
Washington, D.C. 20240
Phone: 202-208-4378
On line: www.bsee.gov

Addendum 5, December 2019
<table>
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<th>Association</th>
<th>Address</th>
<th>Phone</th>
<th>Fax</th>
<th>Website</th>
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<tbody>
<tr>
<td>Canadian National Energy Board (NEB)</td>
<td>517 Tenth Avenue SW, Calgary, Alberta, Canada T2R 0A8</td>
<td>800.899.1265</td>
<td>877.288.8803</td>
<td><a href="http://www.neb.gc.ca">www.neb.gc.ca</a></td>
</tr>
<tr>
<td>Canadian Energy Pipeline Association (CEPA)</td>
<td>Suite 200, 505-3rd St. SW, Calgary, Alberta, Canada T2P 3E6</td>
<td>403.221.8777</td>
<td>403.221.8760</td>
<td><a href="http://www.cepa.com">www.cepa.com</a></td>
</tr>
<tr>
<td>Common Ground Alliance (CGA)</td>
<td>707 Prince Street, Arlington, VA 22314</td>
<td>703.836.1709</td>
<td>309.407.2244</td>
<td><a href="http://www.commongroundalliance.com">www.commongroundalliance.com</a></td>
</tr>
<tr>
<td>The Council of Gas Detection and Environmental Monitoring (CoGDEM)</td>
<td>Unit 9, Knowl Piece Business Centre, Knowl Piece, Wilbury Way, Hitchin, Herts, SG4 0TY, UK</td>
<td>+44 1462 434322</td>
<td>+44 1462 434488</td>
<td><a href="http://www.cogdem.org.uk">www.cogdem.org.uk</a></td>
</tr>
<tr>
<td>Ductile Iron Pipe Research Association (DIPRA)</td>
<td>P.O. Box 19206, Golden, CO 80402</td>
<td>205.402.8700</td>
<td></td>
<td><a href="http://www.dipra.org">www.dipra.org</a></td>
</tr>
<tr>
<td>Gas Technology Institute (GRI)</td>
<td>1700 S. Mount Prospect Road, Des Plaines, IL 60018-1804</td>
<td>847.768.0500</td>
<td>847.768.0501</td>
<td><a href="http://www.gastechnology.org">www.gastechnology.org</a></td>
</tr>
<tr>
<td>International Association of Plumbing and Mechanical Officials (IAPMO)</td>
<td>4755 E. Philadelphia Street, Ontario, CA 91761</td>
<td>909.472.4100</td>
<td>909.472.4232</td>
<td><a href="http://www.iapmo.org">www.iapmo.org</a></td>
</tr>
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</table>
ISO  International Organization for Standardization  
1214 Vernier  
Geneva, Switzerland  
Phone: +41 22 749 01 11  
On line: www.iso.org

MSS  Manufacturers Standardization Society [of the Valve and Fittings Industry]  
127 Park Street, NE  
Vienna, VA 22180-4602  
Phone: 703.281.6613  
Fax: 703.281.6671  
On line: msshq.org

NACE  NACE International  
15835 Park Ten Place  
Houston, TX 77084-4906  
Phone: 281.228.6200  800.797.6223  
Fax: 281.228.6300  
On line: www.nace.org

NBBI  National Board of Boiler and Pressure Vessel Inspectors  
1055 Crupper Avenue  
Columbus, Ohio 43229-1183  
Phone: 614.888.8320  
Fax: 614.888.0750  
On line: www.nationalboard.org

NCB  National Coal Board (replaced by The Coal Authority in 1994)  
The Coal Authority  
200 Lichfield Lane  
Mansfield, Nottinghamshire NG18 4RG  
Phone: 0345.762.6848  
On line: www.coal.gov.uk

NFPA  National Fire Protection Association  
1 Batterymarch Park  
Quincy, MA 02169-7471  
Phone: 800.344.3555  
Fax: 800.593.6372  
On line: www.nfpa.org

OPS  Office of Pipeline Safety / PHMSA / DOT  
East Building, 2nd Floor  
1200 New Jersey Avenue, SE  
Washington, DC 20590-0001  
Phone: 202.366.4595  
Fax: 202.366.4566  
On line: www.phmsa.dot.gov/pipeline
5 ADDITIONAL INFORMATION RESOURCES

ACGIH American Conference of Governmental Industrial Hygienists
1330 Kemper Meadow Drive
Cincinnati, Ohio 45240
Phone: 513.742.2020
Fax: 513.742.3355
On line: www.ACGIH.org

ASHRAE American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc.
1791 Tullie Circle, NE
Atlanta, GA 30329
Phone: 404.636.8400
Fax: 404.321.5478
On line: www.ashrae.com
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<tr>
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<tr>
<td>OPS Information Resource Manager Email</td>
<td><a href="mailto:InformationResourcesManager@phmsa.dot.gov">InformationResourcesManager@phmsa.dot.gov</a></td>
<td>§192.727</td>
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<tr>
<td>OPS Integrity Management Database</td>
<td>primis.phmsa.dot.gov/gasimp</td>
<td>§192.949</td>
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<tr>
<td>OPS NPMS homepage</td>
<td><a href="http://www.npms.phmsa.dot.gov">www.npms.phmsa.dot.gov</a></td>
<td>§192.727</td>
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<tr>
<td>OPS Public Education</td>
<td>primis.phmsa.dot.gov/comm/PublicEducation.htm</td>
<td>§192.616</td>
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<td>PPI website</td>
<td><a href="http://www.plasticpipe.org">www.plasticpipe.org</a></td>
<td>§191.9 §191.11 §191.12 §191.15 §191.17 §192.945</td>
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<td>PRCI website</td>
<td><a href="http://www.prci.org">www.prci.org</a></td>
<td>§191.9 §191.11 §191.12 §191.15 §191.17 §192.945</td>
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<td>SSPC website</td>
<td><a href="http://www.sspc.org">www.sspc.org</a></td>
<td>§191.9 §191.11 §191.12 §191.15 §191.17 §192.945</td>
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<tr>
<td>TTI website</td>
<td><a href="http://www.ttoolbox.com">www.ttoolbox.com</a></td>
<td>§191.9 §191.11 §191.12 §191.15 §191.17 §192.945</td>
</tr>
<tr>
<td>UL website</td>
<td><a href="http://www.ul.com">www.ul.com</a></td>
<td>§191.9 §191.11 §191.12 §191.15 §191.17 §192.945</td>
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4.5 Selecting an instrument for the detection of gas.
(a) Operators should consider the following when selecting a detection instrument.
   (1) Usage.
      (i) Leak survey.
      (ii) Leak investigation (first response).
      (iii) Leak classification (barholing).
      (iv) Pinpointing.
   (2) Application.
      (i) Distribution system leak survey.
      (ii) Transmission line leak survey.
      (iii) Emergency response.
      (iv) Pinpointing.
   (3) Limitations.
      (i) Sensitivity.
      (ii) Type of sample system.
      (iii) Weather related issues, such as wind, moisture, frost, snow, and ice.
      (iv) Any condition that may limit detection capability of instrument.
(b) See Table 2 for a listing of available technologies.

4.6 Maintenance of instruments.
Each instrument used for leak detection and evaluation should be operated in accordance with the
manufacturer’s recommended operating instructions and:
(a) Should be periodically “checked” while in use to ensure that the recommended voltage requirements
    are available.
(b) Should be tested daily or prior to use to ensure proper operation, to ensure that the sampling system
    is free of leakage, and to ensure that the filters are not obstructing the sample flow.
(c) Any instrument used for leak survey should be tested for operation at each start-up and periodically
    tested during a survey.

4.7 Calibration of instruments.
Each instrument used for leak detection and evaluation should be calibrated at the following times in
accordance with the manufacturer’s recommended calibration instructions.
(a) After any repair or replacement of parts.
(b) On a regular schedule giving consideration to the type and usage of the instrument involved. HFI
    systems and CGI instruments should be checked for calibration at least once each month while in
    use.
(c) At any time it is suspected that the instrument’s calibration has changed.

5 LEAK INVESTIGATION AND CLASSIFICATION

5.1 Scope.
(a) Leak investigation and leak classification provide a means for determining the location, extent, and
potential hazard of migrating gas. A leak investigation should be initiated to address a report of a
possible leak indication. Prompt action should be taken as necessary for protection of people first
and then property. Leak indications may include the following.
   (1) Odor complaints.
   (2) Reports of dead or discolored vegetation.
   (3) Positive readings from leak detection equipment.
(b) Leak indications may originate from the following.
   (1) Scheduled leak surveys.
   (2) Line patrols.
   (3) Customer reports.
   (4) Reports from the general public.
(c) Regardless of their origin, leak indications should be investigated promptly to identify any hazardous condition.
(d) In any leak investigation, an operator should presume that a Grade 1 or hazardous leak might exist.
(e) Only after completing the leak investigation should an operator determine an appropriate leak classification. Leak indications may be from sources other than natural gas.

5.2 Procedural Guidance – General.
(a) If a leak investigation is initiated by an "inside" odor complaint, see 5.4 below.
(b) There are situations that might warrant entering a building before checking the extent of gas migration. These can include the following.
   (1) Broken gas lines.
   (2) Gas blowing out of the ground.
   (3) Hissing, roaring, or other sounds indicating underground gas leakage.
   (4) Noticeable odor levels.
   (5) Gas in multiple underground structures that are normally connected by ducts or piping to houses, especially when the gas readings are high.
   (6) Inside odor reports in an area of underground leakage or coincident with outside odor reports.
(c) Where a leak indication appears to originate from buried piping, operator personnel should identify the extent of gas migration. If the migration pattern extends to nearby structures, the structures should be immediately checked for the presence of combustible gases. Structures may include buildings, confined spaces, and other buried utilities. See 5.3 below. Considerations should include the following.
   (1) If gas is found within a structure, other structures within the boundaries of the migration pattern should be checked for the presence of gas. Based on the local conditions, structures beyond the identified migration pattern may also need to be checked.
   (2) The levels of gas migrating into buildings need to be monitored so that the "make safe" actions can be initiated at appropriate times. Under these and similar conditions, it is recommended that immediate assistance be requested and the inside investigations be initiated without delay, including finding the farthest extent of gas migration.
   (3) Because leakage can be dynamic, the gas levels in nearby buildings need to be continually monitored. It is not uncommon, under extreme conditions, for buildings that had no gas detected on the initial check to have gas levels found upon subsequent checks.
(d) Personnel investigating a leak indication reported as either an "inside" or "outside" complaint should perform a visual check for the existence of other underground utilities in the area. If "outside," see 5.3 below. Examples of other underground facilities in the area of suspected gas migration include the following.
   (1) Customer-owned service lines.
   (2) Buried fuel lines.
   (3) Electric lines.
   (4) Telephone wiring.
   (5) Television cables.
   (6) Water or sewer lines.
(e) Consider the potential for gas migration under fully paved areas, ground frost, or buildings.

5.3 Procedural Guidance – Outside underground leak.
(a) Using a barhole device and CGI, barhole in the area of indication along and adjacent to operator’s mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. See 4.4(b) above.
   Note: Use caution when barholing to avoid damage to operator facilities or other underground structures.
(b) Barholing of an underground leak indication should be done in a uniform manner. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Once the area of the leak indication is determined, barhole and sample with the CGI in all directions from the approximate center of the leak until zero gas readings are detected.
Note: If the leakage pattern extends to the outside wall of a structure, the leak investigation should continue to the inside of the structure.

(c) If a meter set is outside, observe its dial for unusual flow.

(d) Look for indications of construction activity, which might have caused damage to the operator's facilities. Examples are:
   (1) Excavation.
   (2) Pavement patches.
   (3) Landscaping.
   (4) Fencing installation.
   (5) Directional drilling or boring activity.
   (6) Settling or subsidence.

(e) Look for building additions that may have been constructed over natural gas service lines.

(f) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak.

(g) Check available openings in the area of a leak indication. These openings may include the following.
   (1) Valve boxes.
   (2) Catch basins.
   (3) Manholes.
   (4) Vaults.
   (5) Water meter boxes.
   (6) Pits.
   (7) Underground irrigation control boxes.
   (8) Other openings that allow access to underground atmospheres.

(h) Check for migration along other buried utilities that may serve as a path for leaking gas. Paths for leaking gas might include the following.
   (1) Sanitary sewer systems.
   (2) Drains and drainage systems.
   (3) Water mains and service lines.
   (4) Telephone lines.
   (5) Electric lines.
   (6) Cable TV lines.

(i) Investigating readings in underground conduit structures.
   (1) Underground conduits (e.g., electric, telephone, cable) or sewer and drain structures (e.g., storm, sanitary, catch basins, vent boxes) can provide unobstructed and interconnected (or exclusive) migration paths for gas. Therefore, if readings are found in these types of structures, the operator should conduct successive checks of all interconnecting manholes until zero readings are found.
   (2) Buildings should also be checked to determine if interconnecting conduits are entering buildings and possibly providing migration of gas to the inside of the building. The investigation may require coverage of numerous blocks and buildings to achieve proper results.
   (3) To determine which manholes are "interconnected," an operator can perform a survey of available openings, noting similarly identified manhole covers. Other techniques include the following.
      (i) Contact and work with the owner-utility directly, or through one-call (observing local one-call laws).
      (ii) Pull the manhole covers and observe (from the surface) the apparent directions of the conduits.

   Note: Rectangular lids are common in the electrical industry. Opening this style of lid can cause damage if the lid drops through the opening. Use extreme caution when opening these lids or ask the owner-utility for assistance.

   (4) After identifying all successive manholes with positive readings and the clear manholes at the ends, all gas facilities between the clear manholes should be considered to be within the area of migration and should be investigated.

   (5) Due to prevailing air flow within conduit systems, it is not unusual for gas leaks to be closer to
manholes with zero readings than those with positive readings.

(6) Ventilate all manholes. This should reduce readings in manholes that are farther from the leak source.

Note: This action can change the pattern of air flow within the conduit system and change readings inside buildings (if conduits connect to the adjacent buildings). Therefore, check buildings as discussed in 5.3(i)(2) above to determine if this should be a concern.

(7) Continue to pinpoint (see 7 below) the leak by barholing as described in the beginning of this section (5.3). If necessary, barhole over or near the conduit to obtain a lead to the source leak. Be cautious of other owner-utilities as discussed in 7.3(a).

(j) If a leak area involves multiple buildings, the leak investigation area should be expanded to include each building in the affected area. Consider extending the leak investigation area one or two buildings, or a specified distance, beyond the leak migration area.

(k) If a leak is detected on aboveground exposed piping, perform a bubble test using a leak detection solution to determine the magnitude of the leak. See 4.4(e) above.

(l) Based on the location, extent of migration, and leak magnitude, assign a leak classification to the leak area. See Tables 3a, 3b, and 3c.

5.4 Procedural Guidance – Inside leak or odor complaint.

(a) It may be necessary to investigate a reported leak or gas odor inside a structure. These investigations may result from the following.

(1) Gas migration.
(2) Indications of gas readings while performing routine leak surveys.
(3) Odor complaints.

(b) Leaks may originate on customer-owned piping or equipment.

(c) Look for indications of construction activity, which might have caused damage to the operator's facilities. Examples are:

(1) Excavation.
(2) Pavement patches.
(3) Landscaping.
(4) Fencing installation.
(5) Directional drilling or boring activity.
(6) Settling or subsidence.

(d) Look for building additions that may have been constructed over natural gas service lines.

(e) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak. See 5.3 above.

(f) The CGI and an approved flashlight should be turned on prior to entering any building or structure.

(g) If there is an outside meter set, observe its dial for excessive flow or movement.

(h) Using a CGI, test around the entry door for gas indications. Do not ring the door bell; knock on the door to get the attention of occupants. Upon entry do not operate any lights, but do take appropriate precautions to prevent accidental ignition. Immediately sample the inside atmosphere for the presence of a combustible gas.

Note: If gas is detected, the applicable portions of the operator's emergency procedures need to be implemented.

(i) If the call is an odor complaint, proceed to the area indicated by the caller/occupant to investigate. When entering a building as a result of detecting a leak on outside underground piping, initiate an "inside" investigation. If the visit is in response to an odor complaint, attempt to locate and identify all gas lines associated with the building to their respective points of termination or equipment connection. Observe for abandoned or inactive natural gas lines, and natural gas lines that may exist under a portion of the structure that has no basement (e.g., an addition, garage).
6.3 Self audits.

In order that the completeness and effectiveness of the leak detection and repair program may be evaluated, self-audits should be performed on the following.

(a) Schedule of leak survey. The operator should ensure that the schedule is commensurate with Subpart M, and the general condition of the pipeline system.

(b) Survey completeness. The operator should ensure that records, such as maps, provided to the leak surveyor are sufficiently complete to meet the leak survey requirements. The following are examples that may be considered when evaluating survey completeness.

1. Tagging (e.g., using a two-part numbered tag) will help document completion of the leak survey in a given area.
   (i) Place tags on selected meter sets in the survey area ahead of the scheduled leak survey.
   (ii) Meter tags should be dated when placed.
   (iii) Survey technicians should then be required to return collected tags at the conclusion of the survey day.

2. GPS tracking. Real-time GPS tracking of leak survey progress and completion can be plotted on system maps.

(c) Survey effectiveness. The operator should evaluate leak survey results to ensure that, throughout the system, an effective leakage survey is being performed. The following are examples that may be considered for this evaluation.

1. Leakage survey audits. Leakage survey audits may include a re-inspection of selected areas on a percentage basis (e.g., 10% of a given map area), by another survey technician, a supervisor, or a third-party using the same equipment. Audits should be concluded as soon as possible after the completion of the original survey to avoid variations in venting conditions. During an audit, classified leaks should be evaluated for the accuracy of classification according to the operator's written procedures.

2. Detected leaks versus mechanical failure or damage. Evaluate variations in leakage data in areas where there is a likelihood of failure from system components (e.g., mechanical couplings or tees, risers), historical third-party damage, or outside forces (e.g., settling or subsidence). Evaluate both aboveground and underground leaks.

3. Detected leaks versus corrosion data. Consider plotting leakage data in conjunction with corrosion data on protected and unprotected piping systems. An increase in corrosion-related leaks from one survey cycle to the next might indicate a significant change in the cathodic protection system on a given pipeline. Conversely, a reduction in reported corrosion-related leaks from one survey cycle to the next might indicate an issue with the performance of the survey.

4. Detected leaks by area, map, town, mile, or pipe segment. Evaluate historical leak history data monthly for unanticipated variations in total leak count.

5. Detected leaks versus confirmed leak calls from the public. Establish a matrix to evaluate the frequency of confirmed underground leaks reported by the public versus leaks detected during normal survey operations. This evaluation should take into account changes in the weather, system demand, and any condition that would cause an artificial increase in leak calls. Data collected for this type of evaluation may span a period of several years or survey cycles. A variance in the ratio may indicate improved or reduced effectiveness of the leak survey program.

6. Recheck program (e.g., 2 or 3 days). This can be used on leaks found during the survey to ensure that found leaks are being classified properly.

(d) Repair scheduling. The operator should ensure that repairs are made within the time specified.

(e) Repair effectiveness. The operator should ensure that leak repairs are effective.

(f) Leak records. The operator should ensure that adequate records are being maintained.
7 PINPOINTING

7.1 Scope.
Pinpointing is the process of tracing a detected gas leak to its source. It should follow an orderly systematic process that uses one or more of the following procedures to minimize excavation. The objective is to prevent unnecessary excavation which is more time consuming and costly than time spent pinpointing a leak.

7.2 Procedural Guidance.
(a) The migration of gas should be determined by establishing the outer boundaries of the indications. This will define the area in which the leak will normally be located. These tests should be made with a CGI without expending excessive effort providing sample points.
(b) In an urban environment, sampling is recommended at available openings (e.g., manholes, valve boxes) in the area. Testing such structures provides advantages in determining migration when pinpointing a leak, such as the following.
   (1) Identifying the spread through efficient use of existing structures, thus minimizing barholes.
   (2) Reducing the risk of damaging other utilities during the investigation.
   (3) Expediting the investigation.
(c) All gas lines should be located to narrow the area of search. Particular attention should be paid to the location of valves, fittings, tees, stubs, and connections, the latter having a relatively high probability of leakage. Caution should be exercised to prevent damage to other underground structures during barring or excavating.
(d) Foreign facilities in the area of search should be identified. The operator should look for evidence of recent construction activities that could have contributed to the leakage. Gas may also migrate and vent along a trench or bore hole provided for other facilities. Leaks could occur at the intersection of the foreign facility and the gas pipeline. Particular attention should be given to these intersections.
(e) Evenly spaced bar or test holes should be used over the gas line suspected to be leaking. All barholes should be of equal depth and diameter (and down to the pipe depth where necessary) and all CGI readings should be taken at an equal depth in order to obtain consistent and worthwhile readings. Using only the highest sustained readings, the gas can be traced to its source by identifying the test holes with the highest readings.
(f) Frequently, high readings are found in more than one barhole and additional techniques are necessary to determine which reading is closest to the probable source. Many of the barhole readings will normally decline over a period of time but it may be desirable to dissipate excess gas from the underground locations to hasten this process. Evaluation methods should be used with caution to avoid distorting the venting patterns.
(g) Once underground leakage has been identified, additional holes and deeper holes should be probed to more closely bracket the area. For example, test holes may be spaced six feet apart initially and then the six foot spacing between the two highest test holes might be probed with additional test holes, with spacing as close as twelve inches.
(h) Additional tests include taking CGI readings at the top of a barhole or using manometer or bubble forming solution to determine which barhole has the greatest positive flow. Other indications are dust particles blowing from the barholes, the sound of gas coming from the barhole or the feel of gas flow on a sensitive skin surface. On occasion, sunlight diffraction can be observed as the gas vents to the atmosphere.
(i) Testing at available openings may be used to isolate the source in addition to the techniques previously mentioned. Many times the leak is found at the intersection of the foreign conduit and a gas line. Particular attention should be given to these locations.
(j) Pinpointing a leak entering an underground conduit, sewer, or drain may require the investigation to extend to the first subsurface structure, in each direction, which has no readings. See 5.3(i) above.
(k) When the pattern of the CGI readings has stabilized, the barhole with the highest reading will usually pinpoint the gas leak.
(l) The operator should test with bubble forming solution where piping has been exposed, particularly to locate smaller leaks.
GUIDE MATERIAL APPENDIX G-192-11A
(See guide material under §§192.3, 192.11, 192.503 192.557, 192.615, 192.703, and 192.723)

GAS LEAKAGE CONTROL GUIDELINES
FOR PETROLEUM GAS SYSTEMS
(See Guide Material Appendix G-192-11 for natural gas systems)

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TABLE 2 – AVAILABLE PROPANE DETECTION TECHNOLOGIES
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4.3 Odors or indications from foreign sources.
When leak indications (e.g., gasoline vapors, natural, petroleum, sewer or marsh gas) are found to originate from a foreign source or facility, or customer-owned piping, prompt actions should be taken where necessary to protect life and property. Potentially hazardous leaks should be reported promptly to the operator of the facility and, where appropriate, to the police department, fire department, or other governmental agency. When the operator's pipeline is connected to a foreign facility (e.g., the customer's piping) necessary action should be taken to eliminate the potential hazard, such as disconnecting or shutting off the flow of gas to the facility.

4.4 Leak surveys and test methods.
For leak surveys, see the limitations under §§192.706 and 192.723 regarding leak detection equipment. The following gas leak surveys and test methods may be employed, as applicable, in accordance with written procedures.
— Subsurface Gas Detection Survey (including barhole surveys)
— Bubble Leakage Test
— Pressure Drop Test
Other survey and test methods may be employed if they are deemed appropriate and are conducted in accordance with procedures that have been tested and proven to be at least equal to the methods listed in this section.

The Surface Gas Detection Survey and Vegetation Survey methods used for natural gas systems are not recommended for use on petroleum gas systems. Petroleum gases are heavier than air and will frequently not come to the ground surface or cause surface indications in the vegetation. However, the Surface Gas Detection Survey, when properly conducted by taking into account that the gas is heavier than air, may be used adjacent to above ground facilities.

(a) Subsurface Gas Detection Survey.
   (1) Definition. The sampling of the subsurface atmosphere with a CGI or other device capable of detecting 10% of the LEL at the sample point.
   (2) Procedural Guidance. The survey should be conducted by performing tests with a series of barholes immediately adjacent to the gas facility and in available openings (confined spaces and small substructures). The following should be considered when selecting the placement of barholes and sample points.
   (i) The location of the gas pipelines and proximity to buildings or other structures.
   (ii) Approximate depth of buried gas piping.
   (iii) Extent of pavement.
   (iv) Soil type and moisture content.
   (v) Available subsurface openings (e.g., valve boxes, catch basins, manholes).
   (vi) Underground conduit and sewer structures can provide unobstructed and interconnected (or exclusive) migration paths toward buildings. If readings are found in these structures, further investigation should follow. See 5.3(i) below.

Barhole sample points should be placed along or adjacent to the pipeline, to the approximate depth of the pipeline, and at intervals of 20 feet or less. The sampling pattern should include tests at the building wall at the service riser or point of service line entrance. Consideration should be given to threaded or mechanical joints that have had a history of leakage. Available subsurface openings adjacent to the pipeline should be tested. Where the piping system passes under pavement for a distance of 20 feet or less, barholes should be made at the point of entrance and exit of the paved area. Where the paved area over the pipeline is 20 feet or greater in length, sample points should be located at intervals of 20 feet or less. In the case of extensive pavement, permanent sample points should be considered.
When testing available openings for petroleum gas, readings should be taken at both the top and bottom of the structure. When testing larger confined spaces or basements, the floor areas, including floor drains, should be thoroughly tested because petroleum gases can lie temporarily in pockets containing explosive mixtures. Since migrating gas may not enter at the pipeline entrance, a perimeter survey of the floors and walls is recommended. When conducting the survey, all barholes should penetrate to the pipe depth, where necessary, in order to obtain consistent and worthwhile readings. This includes penetrating through capping materials such as paving, concrete, frost, or surface sealing by ice or water. The required depth of the barhole will also depend upon the soil conditions, the depth of and pressure in the pipeline, and the type of instrument being used. The readings should be taken at the bottom of the bar. The probe used should be equipped with a device to preclude the drawing in of liquids. When conducting the survey, the inspector should use the most sensitive scale on the instrument, watching for small indications of combustible gas. Any indication should be further investigated to determine the source of the gas. Care should be taken to avoid damaging the pipe or coating with the probe bar.

(3) Utilization. This survey method should be utilized for buried facilities. Good judgment should be used to determine when the recommended spacing of sample points is inadequate. Additional sample points should be provided under these conditions. Available openings (e.g., manholes, vaults, valve boxes) should be tested. However, they should not be relied upon as the only points used to test for petroleum gas leakage.

(4) Precaution. When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation.

(b) Bubble Leakage Test.

(1) Definition. The application of a soap-water or other bubble forming solutions on exposed piping to determine the existence of a leak.

(2) Procedural Guidance. The exposed piping systems should be reasonably cleaned and completely coated with the solution. Leaks are indicated by the presence of bubbles. The bubble forming solution should not be used on piping unless it has been determined by investigation or test that the piping is adequately resistant to direct contact with the solution.

(3) Utilization. This test method may be used for the following.

(i) Testing exposed aboveground portions of a system, such as meter set assemblies or exposed piping on bridge crossings.

(ii) Testing a tie-in joint or leak repair that is not included in a pressure test.

(c) Pressure Drop Test.

(1) Definition. A test to determine if an isolated segment of pipeline loses pressure due to leakage.

(2) Procedural Guidance. Facilities selected for pressure drop tests should first be isolated and then tested. The following criteria should be considered in determining test parameters.

(i) Test Pressure. A test conducted on existing facilities solely for the purpose of detecting leakage should be performed at a pressure at least equal to the operating pressure. A pressure test conducted for the purpose of line qualification or uprating must be performed in accordance with the requirements of Subparts J or K.

(ii) Test Medium. The test medium used must comply with the requirements of §192.503(b).

(iii) Test Duration. The duration of the test should be of sufficient length to detect leakage. The following should be considered in the determination of the duration.

(A) The volume under test.

(B) The time required for the test medium to become temperature stabilized.

(C) The sensitivity of the test instrument.

(3) Utilization. Pressure drop tests should be used only to establish the pressure or absence of a leak on a specifically isolated segment of a pipeline. Normally, this type of test will not provide a leak location. Therefore, facilities on which leakage is indicated may require further evaluation by another detection method in order that the leak may be located, evaluated, and graded.
4.5 Selecting an instrument for the detection of gas.
   (a) Operators should consider the following when selecting a detection instrument.
       (1) Usage.
           (i) Leak survey.
           (ii) Leak investigation (first response).
           (iii) Leak classification (barholing).
           (iv) Pinpointing.
       (2) Application.
           (i) Distribution system leak survey.
           (ii) Transmission line leak survey.
           (iii) Emergency response.
           (iv) Pinpointing.
       (3) Limitations.
           (i) Sensitivity.
           (ii) Type of sample system.
           (iii) Weather related issues, such as wind, moisture, frost, snow, and ice.
           (iv) Any condition that may limit detection capability of instrument.
   (b) See Table 2 for a listing of available technologies.

4.6 Maintenance of instruments.
   Each instrument used for leak detection and evaluation should be operated in accordance with the
   manufacturer's recommended operating instructions and:
   (a) Should be periodically "checked" while in use to ensure that the recommended voltage requirements
       are available.
   (b) Should be tested daily or prior to use to ensure proper operation, to ensure that the sampling system
       is free of leakage, and to ensure that the filters are not obstructing the sample flow.
   (c) Any instrument used for leak survey should be tested for operation at each start-up and periodically
       tested during a survey.

4.7 Calibration of instruments.
   (a) When to calibrate.
       Each instrument used for leak detection and evaluation should be calibrated at the following times in
       accordance with the manufacturer's recommended calibration instructions.
       (1) After any repair or replacement of parts.
       (2) On a regular schedule giving consideration to the type and usage of the instrument involved. HFI
           and CGI instruments should be checked for calibration at least once each month while in use.
       (3) At any time it is suspected that the instrument's calibration has changed.
   (b) Conversion curves.
       It is not essential that instruments used to conduct petroleum gas system leak surveys be calibrated
       specifically for the gas being distributed. However, it is essential that the instrument be properly
       calibrated for the gas specified by the manufacturer and that conversion curves for the appropriate
       petroleum gas be obtained from the manufacturer or be developed by the operator. Without proper
       calibration and the appropriate conversion curves, the operator cannot interpret meter readings or
       determine concentrations. For example, hot-wire CGI instruments calibrated for methane or natural
       gas will read true for propane on the LEL scale (2.0% propane in air will read 100% LEL on the
       meter). On dual-scale instruments calibrated for natural gas, a 100% propane concentration will not
       read 100% gas.
5 LEAK INVESTIGATION AND CLASSIFICATION

5.1 Scope.
(a) Leak investigation and leak classification provide a means for determining the location, extent, and potential hazard of migrating gas. A leak investigation should be initiated to address a report of a possible leak indication. Prompt action should be taken as necessary for protection of people first and then property. Leak indications may include the following.
   (1) Odor complaints.
   (2) Reports of dead or discolored vegetation.
   (3) Positive readings from leak detection equipment.
(b) Leak indications may originate from the following.
   (1) Scheduled leak surveys.
   (2) Line patrols.
   (3) Customer reports.
   (4) Reports from the general public.
(c) Regardless of their origin, leak indications should be investigated promptly to identify any hazardous condition.
(d) In any leak investigation, an operator should presume that a Grade 1 or hazardous leak might exist.
(e) Only after completing the leak investigation should an operator determine an appropriate leak classification. Leak indications may be from sources other than petroleum gas.

5.2 Procedural Guidance – General.
(a) Petroleum gas is heavier than air, and will tend to migrate downward. Leaking petroleum gas will establish flow patterns that may follow utility trench lines and the natural topography of the leak area. Petroleum gas leak patterns will be affected by the presence of a perched water table in the leak area. The petroleum gas leak pattern will change or move with the water table due to seasonal changes. When investigating a petroleum gas leak, look for low spots or dips in the roadway and around the foundations of structures where the gas is likely to accumulate.
(b) If a leak investigation is initiated by an inside odor complaint, see 5.4 below.
(c) There are situations that might warrant entering a building before checking the extent of gas migration. These can include the following.
   (1) Broken gas lines.
   (2) Gas blowing out of the ground.
   (3) Hissing, roaring, or other sounds indicating underground gas leakage.
   (4) Noticeable odor levels.
   (5) Gas in multiple underground structures that are normally connected by ducts or piping to houses, especially when the gas readings are high.
   (6) Inside odor reports in an area of underground leakage or coincident with outside odor reports.
(d) Where a leak indication appears to originate from buried piping, operator personnel should identify the extent of gas migration. If the migration pattern extends to nearby structures, the structures should be immediately checked for the presence of combustible gases. Structures may include buildings, confined spaces, and other sub-surface structures. See 5.3 below. Considerations should include the following.
   (1) If gas is found within a structure, other structures within the boundaries of the migration pattern should be checked for the presence of gas. Based on the local conditions, structures beyond the identified migration pattern may also need to be checked.
   (2) The levels of gas migrating into buildings need to be monitored so that the "make safe" actions can be initiated at appropriate times. Under these and similar conditions, it is recommended that immediate assistance be requested and the inside investigations be initiated without delay, including finding the farthest extent of gas migration.
   (3) Because leakage can be dynamic, the gas levels in nearby buildings need to be continually monitored. It is not uncommon, under extreme conditions, for buildings that had no gas detected on the initial check to have gas levels found upon subsequent checks.
(e) Personnel investigating a leak indication reported as either an "inside" or "outside" complaint should perform a visual check for the existence of other underground utilities in the area. If "outside," see 5.3 below. Examples of other underground facilities in the area of suspected gas migration include the following.

1. Customer-owned service lines.
2. Buried fuel lines.
3. Electric lines.
4. Telephone wiring.
5. Television cables.
6. Water or sewer lines.

(f) Consider the potential for gas migration under fully paved areas, ground frost, or buildings.

5.3 Procedural Guidance – Outside underground leak.

(a) Using a barhole device and CGI, barhole in the area of leak indication along and adjacent to operator’s mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, and risers or service entry points to buildings. See 4.4(a) above.

Note: Use caution when barholing to avoid damage to operator facilities or other underground structures.

(b) Barholing of an underground leak indication should be done in a uniform manner. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Barholes should be placed to the approximate depth of the operator’s piping. Once the area of the leak indication is determined, barhole and sample with the CGI in all directions from the approximate center of the leak until zero gas readings are detected.

Note: If the leakage pattern extends to the outside wall of a structure, the leak investigation should continue to the inside of the structure.

(c) If a meter set is outside, observe its dial for unusual flow.

(d) Look for indications of construction activity that might have caused damage to the operator’s facilities. Examples are:

1. Excavation.
2. Pavement patches.
3. Landscaping.
4. Fencing installation.
5. Directional drilling or boring activity.
6. Settling or subsidence.

(e) Look for building additions that may have been constructed over petroleum gas service lines.

(f) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak.

(g) Check available openings in the area of a leak indication. These openings may include the following.

1. Valve boxes.
2. Catch basins.
4. Vaults.
5. Water meter boxes.
6. Pits.
8. Other openings that allow access to underground atmospheres.

(h) Check for migration along other buried utilities that may serve as a path for leaking gas. Paths for leaking gas might include the following.

1. Sanitary sewer systems.
2. Drains and drainage systems.
3. Water mains and service lines.
4. Telephone lines.
5. Electric lines.
(6) Cable TV lines.
   (i) Investigating readings in underground conduit structures.
   (1) Underground conduits (e.g., electric, telephone, cable) or sewer and drain structures (e.g., storm, sanitary, catch basins, vent boxes) can provide unobstructed and interconnected (or exclusive) migration paths for gas. Therefore, if readings are found in these types of structures, the operator should conduct successive checks of all interconnecting manholes until zero readings are found.
   (2) Buildings should also be checked to determine if interconnecting conduits are entering buildings and possibly providing migration of gas to the inside of the building. The investigation may require coverage of numerous blocks and buildings to achieve proper results.
   (3) To determine which manholes are "interconnected," an operator can perform a survey of available openings, noting similarly identified manhole covers. Other techniques include the following.
      (i) Contact and work with the owner-utility directly, or through one-call (observing local one-call laws).
      (ii) Pull the manhole covers and observe (from the surface) the apparent directions of the conduits.
           Note: Rectangular lids are common in the electrical industry. Opening this style of lid can cause damage if the lid drops through the opening. Use extreme caution when opening these lids or ask the owner-utility for assistance.
   (4) After identifying all successive manholes with positive readings and the clear manholes at the ends, all gas facilities between the clear manholes should be considered to be within the area of migration and should be investigated.
   (5) Due to prevailing air flow within conduit systems, it is not unusual for gas leaks to be closer to manholes with zero readings than those with positive readings.
   (6) Ventilate all manholes. This should reduce readings in manholes that are farther from the leak source.
      Note: This action can change the pattern of air flow within the conduit system and change readings inside buildings (if conduits connect to the adjacent buildings). Therefore, check buildings as discussed in 5.3(i)(2) above to determine if this should be a concern.
   (7) Continue to pinpoint (see 7 below) the leak by barholing as described in the beginning of this section (5.3). If necessary, barhole over or near the conduit to obtain a lead to the source leak. Be cautious of other owner-utilities as discussed in 7.3(a).
   (j) If a leak area involves multiple buildings, the leak investigation area should be expanded to include each building in the affected area. Consider extending the leak investigation area one or two buildings, or a specified distance, beyond the leak migration area.
   (k) If the leak is detected on aboveground exposed piping, perform a bubble test using a leak detection solution to determine the magnitude of the leak. See 4.4(b) above.
   (l) Based on the leak location, extent of migration, and magnitude, assign a leak classification to the leak area. See Tables 3a, 3b, and 3c.

5.4 Procedural Guidance – Inside leak or odor complaint.
   (a) It may be necessary to investigate a reported leak or gas odor inside a structure. These investigations may result from the following.
      (1) Gas migration.
      (2) Indications of gas readings inside a building while performing routine leak surveys.
      (3) Odor complaints.
   (b) Leaks may originate on customer-owned piping or equipment.
   (c) Look for indications of construction activity, which may have caused damage to the operator's facilities. Examples are:
      (1) Excavation.
      (2) Pavement patches.
      (3) Landscaping.
(n) Pipe description.
(o) Type repair.
(p) Leak cause.
(q) Date pipe installed (if known).
(r) Under cathodic protection? (Yes — No).
(s) Magnitude of CGI indication.

6.2 Leak survey records.
For the current and immediately previous survey of an area, the following information should be available.
(a) Description of system and area surveyed. (This could include maps or leak survey logs or both.)
(b) Survey results.
(c) Survey method.
(d) Names of those making survey.
(e) Survey dates.
(f) In addition to the above, the following records should be kept for a pressure drop test.
   (1) The name of the operator, the name of the operator's employee responsible for making the test, and the name of any test company used.
   (2) Test medium used.
   (3) Test pressure.
   (4) Test duration.
   (5) Pressure recording charts, or other record of pressure readings.
   (6) Test results.

6.3 Self audits.
In order that the completeness and effectiveness of the leak detection and repair program may be evaluated, self-audits should be performed on the following.
(a) Schedule of leak survey. The operator should ensure that the schedule is commensurate with Subpart M, and the general condition of the pipeline system.
(b) Survey completeness. The operator should ensure that records, such as maps, provided to the leak surveyor are sufficiently complete to meet the leak survey requirements. The following are examples that may be considered when evaluating survey completeness.
   (1) Tagging (e.g., using a two-part numbered tag) will help document completion of the leak survey in a given area.
      (i) Place tags on selected meter sets in the survey area ahead of the scheduled leak survey.
      (ii) Meter tags should be dated when placed.
      (iii) Survey technicians should then be required to return collected tags at the conclusion of the survey day.
   (2) GPS tracking. Real-time GPS tracking of leak survey progress and completion can be plotted on system maps.
(c) Survey effectiveness. The operator should evaluate leak survey results to ensure that, throughout the system, an effective leakage survey is being performed. The following are examples that may be considered for this evaluation.
   (1) Leakage survey audits. Leakage survey audits may include a re-inspection of selected areas on a percentage basis (e.g., 10% of a given map area), by another survey technician, a supervisor, or a third-party using the same equipment. Audits should be concluded as soon as possible after the completion of the original survey to avoid variations in venting conditions. During an audit, classified leaks should be evaluated for the accuracy of classification according to the operator's written procedures.
   (2) Detected leaks versus mechanical failure or damage. Evaluate variations in leakage data in areas where there is a likelihood of failure from system components (e.g., mechanical couplings or tees, risers), historical third-party damage, or outside forces (e.g., settling or subsidence). Evaluate both aboveground and underground leaks.
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(4) Detected leaks by area, map, town, mile, or pipe segment. Evaluate historical leak history data monthly for unanticipated variations in total leak count.

(5) Detected leaks versus confirmed leak calls from the public. Establish a matrix to evaluate the frequency of confirmed underground leaks reported by the public versus leaks detected during normal survey operations. This evaluation should take into account changes in the weather, system demand, and any condition that would cause an artificial increase in leak calls. Data collected for this type of evaluation may span a period of several years or survey cycles. A variance in the ratio may indicate improved or reduced effectiveness of the leak survey program.

(6) Recheck program (e.g., 2 or 3 days). This can be used on leaks found during the survey to ensure that found leaks are being classified properly.

(d) Repair scheduling. The operator should ensure that repairs are made within the time specified.

(e) Repair effectiveness. The operator should ensure that leak repairs are effective.

(f) Leak records. The operator should ensure that adequate records are being maintained.

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(a) The migration of gas should be determined by establishing the outer boundaries of the indications. This will define the area in which the leak will normally be located. These tests should be made with a CGI without expending excessive effort providing sample points.

(b) In an urban environment, sampling is recommended at available openings (e.g., manholes, valve boxes) in the area. Testing such structures provides advantages in determining migration when pinpointing a leak, such as the following.

(1) Identifying the spread through efficient use of existing structures, thus minimizing barholes.

(2) Reducing the risk of damaging other utilities during the investigation.

(3) Expediting the investigation.

(c) All gas lines should be located to narrow the area of search. Particular attention should be paid to the location of valves, fittings, tees, stubs, and connections, the latter having a relatively high probability of leakage. Caution should be exercised to prevent damage to other underground structures during barring or excavating.

(d) Foreign facilities in the area of search should be identified. The operator should look for evidence of recent construction activities that could have contributed to the leakage. Gas may also migrate and vent along a trench or bore hole provided for other facilities. Leaks could occur at the intersection of the foreign facility and the gas pipeline. Particular attention should be given to these intersections.

(e) Evenly spaced bar or test holes should be used over the gas line suspected to be leaking. All barholes should be of equal depth and diameter (and down to the pipe depth where necessary) and all CGI readings should be taken at an equal depth in order to obtain consistent and worthwhile readings. Using only the highest sustained readings, the gas can be traced to its source by identifying the test holes with the highest readings.
GUIDE MATERIAL APPENDIX G-192-17
(See Part 191 and guide material under §§192.13, 192.603, 192.941, and 192.947)

**EXPlicit Requirements for Reports, Inspections, Tests, Written Procedures, Records, or Similar Actions**

Part 191 and Part 192 include requirements for reports, inspections, tests, written procedures, records, and similar actions on the part of the operator. This table is a listing of each regulation section that clearly and precisely states such requirements and the actions to be taken. The operator is advised that other types of required actions are not intended to be included in this listing. The term "written" is only included in the "Requirements" column where explicitly used in the regulation section, even though it may be otherwise implied. This table does not include other requirements contained in documents that are incorporated by reference.

This table is provided as an aid and does not remove the responsibility of the operator concerning total adherence to the Regulations, whether required, implied, prudent, or practical.

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