GAS PIPING technology committee

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February 1, 2023

Dear *Guide* Purchaser,

Enclosed is ANSI/GPTC Z380.1, *Guide for Gas Transmission, Distribution, and Gathering Piping Systems,* 2022 Edition, which includes Addenda 1 and 2.

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,

Secretary
GPTC Z380

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GPTC GUIDE FOR GAS TRANSMISSION, DISTRIBUTION, AND GATHERING PIPING SYSTEMS

2022 EDITION

Addendum 2, February 2023

The changes in this edition 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 was one Federal Regulation update for this period. 13 GPTC transactions affected 16 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, adjustments to page numbering, and adjustment of text on pages. Only significant editorial updates are marked. Editorial updates as indicated "EU" affected 10 sections of the Guide. Most sections were impacted by page adjustments throughout the guide.

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

Key to Reasons for Change
Amdt.19X-XXX or docket number: federal regulation amendment TR YY-XX: GPTC transaction with new or updated guide material EU: editorial update

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Guide for Gas Transmission, Distribution, and Gathering Piping Systems

2022 Edition

Addendum 2, February 2023

An American National Standard

Author:
Gas Piping Technology Committee (GPTC) Z380
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PLEASE NOTE

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.

CAUTION

As part of document purchase, GPTC (using AGA as Secretariat) will try to keep purchasers informed on the current Federal Regulations as released by the Department of Transportation (DOT). This is done by periodically issuing addenda to update both the Federal Regulations and the guide material. It is the responsibility of the purchaser to obtain a copy of any addenda. Addenda are posted on the Committee's webpage at www.aga.org/gptc. The GPTC assumes no responsibility in the event the purchaser does not obtain addenda. The purchaser is reminded that the changes to the Regulations can be found on the Federal Register's web site.

Participation by state and federal agency representative(s) or person(s) affiliated with industry is not to be interpreted as government or industry endorsement of the guide material in this Guide.

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PREFACE

The guide material presented in the Gas Piping Technology Committee's (GPTC) "Guide for Gas Transmission, Distribution, and Gathering Piping Systems" (Guide) contains information and some "how to" methods to assist the operator in complying with the Code of Federal Regulations (CFR), Title 49 as follows:

- Part 191 - Transportation of Natural and Other Gas by Pipeline: Annual Reports, Incident Reports, and Safety-Related Condition Reports
- Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards Parts 191 and 192 are typically referred to hereinafter as the "Regulations."

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 judgment. All guide material is of equal importance and validity, whether immediately following the Regulations or in Guide Material Appendices.

The guide material is advisory in nature and contains guidance and information for consideration in complying with the Regulations. As such, it is not intended for public authorities or others to adopt the Guide in mandatory language, in whole or in part, in laws, regulations, administrative orders, ordinances, or similar instruments as the sole means of compliance.

The operator is cautioned that the guide material may not be adequate under all conditions encountered, and should not restrict the operator from using other methods of complying with the Regulations. Following the Guide does not ensure that an operator is automatically in compliance with the requirements of Parts 191 and 192. Operators of intrastate facilities are also cautioned that some states have additional or more stringent requirements than Parts 191 and 192. Operators of both intrastate and interstate facilities may be subject to state-specific damage prevention requirements.

Operators should recognize that certain activities may also be impacted by other agencies, such as United States Coast Guard (USCG), Transportation Security Administration (TSA), Environmental Protection Agency (EPA), and Occupational Safety and Health Administration (OSHA). For example, TSA has issued pipeline security guidelines to assist pipeline operators in addressing the management of security-related threats, events, and responses.

HISTORY

The Natural Gas Pipeline Safety Act became effective on August 12, 1968. It required the Secretary of Transportation to adopt interim rules within three months which were to consist of the existing state standards, where such standards existed, or the standards common to a majority of states where no state standard existed, and to establish minimum federal standards within twenty-four months. The safety standard for gas pipelines and mains, in the majority of the states, was the American National Standard Code for Pressure Piping, Gas Transmission and Distribution Piping Systems, B31.8. Thus, the interim minimum safety standards were essentially B31.8 Code requirements.

Between August 12, 1968 and August 12, 1970, the Office of Pipeline Safety (OPS) of the United States Department of Transportation (DOT) developed safety standards which would be applicable to gas facilities, with the exception of rural gas gathering systems. As a result, Title 49 Part 192 of the Code of Federal Regulations (CFR) "Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards" became effective November 12, 1970.

Since the sponsoring organization of the ANSI B31.8 Committee was The American Society of Mechanical

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. The 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, a reporting-regulated gathering pipeline, 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.

[Issued by Amdt. 191-6, 53 FR 24942, July 1, 1988 with Amdt. 191-6 Correction, 53 FR 26560, July 13, 1988; Amdt. 191-14, 63 FR 37500, July 13, 1998; Amdt. 191-24, 81 FR 91872, Dec. 19, 2016; Amdt. 191-26, Oct. 1, 2019; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

(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 charts 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.

§191.25

Filing safety-related condition reports.

[Effective Date: 07/01/2020]

(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.

[Issued by Amdt. 191-6, 53 FR 24942, July 1, 1988 with Amdt. 191-6 Correction, 53 FR 26560, July 13, 1988 and Amdt. 191-6 Correction, 53 FR 29800, Aug. 8, 1988; Amdt. 191-7, 54 FR 32342, Aug. 7, 1989; Amdt. 191-8, 54 FR 40878, Oct. 4, 1989; Amdt. 191-10, 61 FR 18512, Apr. 26, 1996; Amdt. 191-23, 80 FR 12762, Mar. 11, 2015, Amdt. 191-26, Oct. 1, 2019]

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.

§191.29

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:

(1) Geospatial data, attributes, metadata and transmittal letter appropriate for use in the National Pipeline Mapping System. Acceptable formats and additional information are specified in the NPMS Operator Standards Manual available at *www.npms.phmsa.dot.gov* or by contacting the PHMSA Geographic Information Systems Manager at (202) 366-4595.

(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.

(c) This section does not apply to gathering pipelines.

[Issued by Amdt. 191-23, 80 FR 12762, Mar. 11, 2015; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

Operators will need to reflect changes due to service conversion or product change (see §191.22(c)(1)(vi)) on subsequent National Pipeline Mapping System submissions.

(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).

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-67, 56 FR 63764, Dec. 5, 1991; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-81, 62 FR 61692, Nov. 19, 1997 with Amdt. 192-81 Confirmation, 63 FR 12659, Mar. 16, 1998; Amdt. 192-92, 68 FR 46109, Aug. 5, 2003; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 192-102, 71 FR 13289, Mar. 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

Additional state requirements may exist for intrastate facilities. A NAPSR document ("Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations," 2nd Edition 2013) provides additional state requirements and is available at www.napsr.org.

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

A reference for hydrogen pipelines is OPS Report No. DOT.RSPA/DMT-10-85-1, "Safety Criteria for the Operation of Gaseous Hydrogen Pipelines," (Discontinued).

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: 05/24/23]

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.**

***Close interval survey* means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.**

***Composite materials* means materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.**

***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 center* means the initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption, as opposed to customers who purchase it for resale, for example:**

(1) At a metering location;

(2) A pressure reduction location; or

(3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

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

Dry gas or dry natural gas **means gas above its dew point and without condensed liquids.**

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.**

Entirely replaced onshore transmission pipeline segments **means, for the purposes of §§192.179 and 192.634, where 2 or more miles, in the aggregate, of onshore transmission pipeline have been replaced within any 5 contiguous miles of pipeline within any 24-month period.**

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.**

Hard spot **means an area on steel pipe material with a minimum dimension greater than two inches (50.8 mm) in any direction and hardness greater than or equal to Rockwell 35 HRC (Brinell 327 HB or Vickers 345 HV_{10})**

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.**

In-line inspection (ILI) **means an inspection of a pipeline from the interior of the pipe using an inspection tool also called** ***intelligent*** **or** ***smart pigging*****. This definition includes tethered and self-propelled inspection tools.**

In-line inspection tool or instrumented internal inspection device **means an instrumented device or vehicle that uses a non-destructive testing technique to inspect the pipeline from the inside in order to identify and characterize flaws to analyze pipeline integrity; also known as an** ***intelligent*** **or** ***smart pig*****.**

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_classifications/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.**

***Notification of potential rupture* means the notification to, or observation by, an operator of indicia identified in §192.635 of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline.**

***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 ºF (38 ºC).**

***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.**

***Rupture-mitigation valve (RMV)* means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture.**

***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 or connected series of pipelines, other than a gathering line, that:**

(1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center;

(2) Has an MAOP of 20 percent or more of SMYS;

(3) Transports gas within a storage field; or

(4) Is voluntarily designated by the operator as a transmission pipeline.

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.**

Wrinkle bend **means a bend in the pipe that:**

(1) Was formed in the field during construction such that the inside radius of the bend has one or more ripples with:

(i) An amplitude greater than or equal to 1.5 times the wall thickness of the pipe, measured from peak to valley of the ripple; or

(ii) With ripples less than 1.5 times the wall thickness of the pipe and with a wrinkle length (peak to peak) to wrinkle height (peak to valley) ratio under 12.

(2) (i) If the length of the wrinkle bend cannot be reliably determined, then w *rinkle bend* means a bend in the pipe where (h/D)*100 exceeds 2 when S is less than 37,000 psi (255 MPa), where (h/D)*100 exceeds (47000— *S*)/10,000 +1 for psi [324— *S*)/69 +1 for MPa] when S is greater than 37,000 psi (255 MPa) but less than 47,000 psi (324 MPa), and where (h/D)*100 exceeds 1 when S is 47,000 psi (324 MPa) or more.

(ii) Where:

(A) D = Outside diameter of the pipe, in. (mm);

(B) h = Crest-to-trough height of the ripple, in. (mm); and
(C) S = Maximum operating hoop stress, psi (S/145, MPa).

[Amdt. 192-13, 38 FR 9083, Apr. 10, 1973; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-67, 56 FR 63764, Dec. 5, 1991; Amdt. 192-72, 59 FR 17275, Apr. 12, 1994 with Amdt. 192-72 Ext., 59 FR 49896, Sept. 30, 1994, Amdt. 192-72 Ext. Correction, 59 FR 52863, Oct. 19, 1994 and Amdt. 192-72 Ext., 60 FR 7133, Feb. 7, 1995; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-81, 62 FR 61692, Nov. 19, 1997 with Amdt. 192-81 Confirmation, 63 FR 12659, Mar. 16, 1998; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-89, 65 FR 54440, Sept. 8, 2000; RIN 2137-AD43, 68 FR 11748, Mar. 12, 2003; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004 and Amdt. 192-94 DFR [Correction], 70 FR 3147, Jan. 21, 2005; Amdt. 192-98, 69 FR 48400, Aug. 10, 2004; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 192-112, 74 FR 63310, Dec. 3, 2009; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015; Amdt 192-122, 81 FR 91872, Dec. 19, 2016; Amdt 192-124, 83 FR 58694, Nov. 20, 2018; Amdt 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294, Nov. 15, 2021; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022, with Correction 87 FR 64384, October 25, 2022]

GUIDE MATERIAL

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

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

§192.7

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

[Effective Date: 05/24/23]

(a) Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved material is available for inspection at Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, 1200 New Jersey Avenue SE, Washington, DC 20590, 202–366–4046 https:// www.phmsa.dot.gov/pipeline/regs, and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, email fr.inspection@nara.gov, or go to www.archives.gov/ federal-register/cfr/ibr-locations.html. It is also available from the sources in the following paragraphs of this section:

	IBR approved for:
(b) American Petroleum Institute (API), 200 Massachusetts Ave. NW, Suite 1100, Washington, DC 20001, and phone: 202–682–8000, website: https:// www.api.org/.	
(1) API Recommended Practice 5L1, ‘‘Recommended Practice for Railroad Transportation of Line Pipe,’’ 7th edition, September 2009, (API RP 5L1).	**§192.65(a).**
(2) API Recommended Practice 5LT, ‘‘Recommended Practice for Truck Transportation of Line Pipe,’’ First edition, March 2012, (API RP 5LT).	**§192.65(c).**
(3) API Recommended Practice 5LW, ‘‘Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels,’’ 3rd edition, September 2009, (API RP 5LW).	**§192.65(b).**
(4) API Recommended Practice 80, ‘‘Guidelines for the Definition of Onshore Gas Gathering Lines,’’ 1st edition, April 2000, (API RP 80).	**§192.8(a).**
(5) API Recommended Practice 1162, ‘‘Public Awareness Programs for Pipeline Operators,’’ 1st edition, December 2003, (API RP 1162).	**§192.616(a), (b), and (c).**
(6) API Recommended Practice 1165, ‘‘Recommended Practice for Pipeline SCADA Displays,’’ First edition, January 2007, (API RP 1165).	**§192.631(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.**
(8) ANSI/API Specification 6D, ‘‘Specification for Pipeline Valves,’’ 23rd edition, effective October 1, 2008, including Errata 1 (June 2008), Errata 2 (November 2008), Errata 3 (February 2009), Errata 4 (April 2010), Errata 5 (November 2010), Errata 6 (August 2011), Addendum 1 (October 2009), Addendum 2 (August 2011), and Addendum 3 (October 2012), (ANSI/API Spec 6D).	**§192.145(a).**

	IBR approved for: (Continued)
(9) API Standard 1104, ''Welding of Pipelines and Related Facilities,'' 20th edition, October 2005, including errata/ addendum (July 2007) and errata 2 (2008), (API Std 1104).	**§§ 192.225(a); 192.227(a); 192.229(b) and (c); 192.241(c); and Item II, Appendix B.**
(10) API Recommended Practice 1170, ''Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage,'' First edition, July 2015 (API RP 1170).	**§ 192.12.**
(11) API Recommended Practice 1171, ''Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs,'' First edition, September 2015, (API RP 1171).	**§ 192.12.**
(12) API STANDARD 1163 "In-Line Inspection Systems Qualification," Second edition, April 2013, Reaffirmed August 2018, (API STD 1163)	**§ 192.493**
(c) ASME International (ASME), Three Park Avenue, New York, NY 10016, phone: 800–843–2763 U.S./Canada), *http://www.asme.org/*.	
(1) ASME/ANSI B16.1–2005, ''Gray Iron Pipe Flanges and Flanged Fittings: Classes 25, 125, and 250),'' August 31, 2006, (ASME/ANSI B16.1).	**§192.147(c).**
(2) ASME/ANSI B16.5–2003, ''Pipe Flanges and Flanged Fittings,'' October 2004, (ASME/ANSI B16.5).	**§§192.147(a) and 192.279 and 192.607(f).**
(3) ASME B16.40–2008, ''Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems,'' March 18, 2008, approved by ANSI (ASME B16.40-2008).	**Item I, Appendix B to Part 192.**
(4) ASME/ANSI B31G–1991 (Reaffirmed 2004), ''Manual for Determining the Remaining Strength of Corroded Pipelines,'' 2004, (ASME/ANSI B31G).	**§§192.485(c), 192.632 (a), 192.712(b), and 192.933(a).**
(5) ASME/ANSI B31.8–2007, ''Gas Transmission and Distribution Piping Systems,'' November 30, 2007, (ASME/ANSI B31.8).	**§§192.112(b) and 192.619(a).**
(6) ASME/ANSI B31.8S–2004, ''Supplement to B31.8 on Managing System Integrity of Gas Pipelines,'' approved January 14, 2005, (ASME/ANSI B31.8S).	**§§ 192.13(d); 192.714(c) and (d); 192.903 note to *potential impact radius*; 192.907 introductory text, (b); 192.911 introductory text, (i), and (k), through (m); 192.913(a), through (c); 192.917(a) through (e); 192.921(a); 192.923(b); 192.925(b); 192.927(b) and (c); 192.929(b); 192.933(c and (d); 192.935(a) and (b); 192.937(c); 192.939(a); and 192.945(a).**
(7) [Reserved]	
(8) ASME Boiler & Pressure Vessel Code, Section VIII, Division 1 ''Rules for Construction of Pressure Vessels,'' 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1).	**§§192.153(a), (b), (d); and 192.165(b).**
(9) ASME Boiler & Pressure Vessel Code, Section VIII, Division 2 ''Alternate Rules, Rules for Construction of Pressure Vessels,'' 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 2).	**§§192.153(b), (d); and 192.165(b).**

	IBR approved for: (Continued)
(24) ASTM F2945-12a, "Standard Specification for Polyamide 11 Gas Pressure Pipe, Tubing and Fittings," Nov. 27, 2012, (ASTM F2945-12a).	Item I, Appendix B to Part 192.
(f) 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: *www.gastechnology.org*.	
(1) GRI 02/0057 (2002), "Internal Corrosion Direct Assessment of Gas Transmission Pipelines Methodology," (GRI 02/0057).	§192.927(c).
(g) Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS), 127 Park St. NE., Vienna, VA 22180, phone: 703–281–6613, Web site: *http://www.mss-hq.org/*.	
(1) MSS SP–44–2010, Standard Practice, "Steel Pipeline Flanges," 2010 edition, (including Errata (May 20, 2011)), (MSS SP–44).	§192.147(a).
(h) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084, phone: 281–228–6223 or 800–797–6223, Web site: *http://www.nace.org/Publications/*.	
(1) NACE Standard Practice 0102—2010, "In-Line Inspection of Pipelines," Revised 2010—03—13, N(NACE SP0102).	§§ 192.150(a) and 192.493
(2) NACE SP0204-2008, Standard Practice, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology," reaffirmed September 18, 2008, (NACE SP0204);	§§ 192.923(b), 192.929(b) introductory text, (b)(1) through (3), (b)(5) introductory text, and (b)(5)(i).
(3) NACE SP0206-2006, Standard Practice, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)," approved December 1, 2006, (NACE SP0206)	IBR approved for §§ 192.923(b); 192.927(b); (c) introductory text, and (c)(1) through (4).
(4) ANSI/NACE SP0502–2010, Standard Practice, "Pipeline External Corrosion Direct Assessment Methodology," revised June 24, 2010, (NACE SP0502).	§§192.319(f); 192.461(h); 192.923(b); 192.925(b); 192.931(d); 192.935(b); and 192.939(a).
(i) National Fire Protection Association (NFPA), 1 Batterymarch Park, Quincy, Massachusetts 02169, phone: 1 617 984–7275, Web site: *http://www.nfpa.org/*.	
(1) NFPA–30 (2012), "Flammable and Combustible Liquids Code," 2012 edition, June 20, 2011, including Errata 30–12–1 (September 27, 2011) and Errata 30–12–2 (November 14, 2011), (NFPA–30).	§192.735(b).
(2) NFPA–58 (2004), "Liquefied Petroleum Gas Code (LP-Gas Code)," (NFPA–58).	§192.11(a), (b), and (c).
(3) NFPA–59 (2004), "Utility LP-Gas Plant Code," (NFPA–59).	§192.11(a), (b), and (c).
(4) NFPA–70 (2011), "National Electrical Code," 2011 edition, issued August 5, 2010, (NFPA–70).	§§192.163(e); and 192.189(c).
(j) Pipeline Research Council International, Inc. (PRCI), c/o Technical Toolboxes, 3801 Kirby Drive, Suite 520, P.O. Box 980550, Houston, TX 77098, phone: 713–630–0505, toll free: 866–866–6766, Web site: *http://www.ttoolboxes.com/*. (Contract number PR–3–805).	
(1) AGA, Pipeline Research Committee Project, PR–3–805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (December 22, 1989), (PRCI PR–3–805 (R–STRENG)).	§§192.485(c); 192.632(a); 192.712(b); 192.933(a) and (d).
(2) [Reserved]	

	IBR approved for: (Continued)
(j) Plastics Pipe Institute, Inc. (PPI), 105 Decker Court, Suite 825, Irving, TX 75062, phone: 469–499–1044, *http://www.plasticpipe.org/*.	
(1) PPI TR–3/2012 HDB/HDS/PDB/SDB/MRS/CRS Policies, ''Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe, '' Updated November 2012. (PPI TR-3/2012)	**§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.**

[Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-51, 51 FR 15333, Apr. 23, 1986; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 192-99, 70 FR 28833, May 19, 2005 with Amdt. 192-99 Correction, 70 FR 35041, June 16, 2005; Amdt. 192-102, 71 FR 13289, Mar.15, 2006; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; RIN 2137-AE29, 73 FR 16562, Mar. 28, 2008; RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; RIN 2137-AE29 (#2), 74 FR 2889, Jan. 16, 2009; RIN 2137-AE42, 74 FR 17099, April 14, 2009 with RIN 2137-AE42 DFR Confirmation, 74 FR 30476, June 26, 2009; Amdt. 192-112, 74 FR 63310, Dec. 3, 2009; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-122, 81 FR 91872, Dec. 19, 2016; Amdt 192-124, 83 FR 58694, Nov. 20, 2018; Amdt 192-125, Oct. 1, 2019; Amdt 192-128, Jan. 11, 2021, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

(a) 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/1661470f45384dc5a4a236373cddfea8.ashx

(2) Area 2(c) example. In Figure 192.8B, Segment A contains 5 houses within the 1000-foot segment. After sliding the 1000-foot corridor to the next dwelling unit, it is determined that Segment B also contains 5 houses within the required 1000 feet. Sliding the 1000-foot corridor to the next dwelling unit, two houses drop out of the corridor and there are not enough houses in Segment C to cause this segment to be regulated. Therefore, the regulated segment begins 150 feet from the upstream side of the first house in Segment A and ends 150 feet from the downstream side of the sixth house.

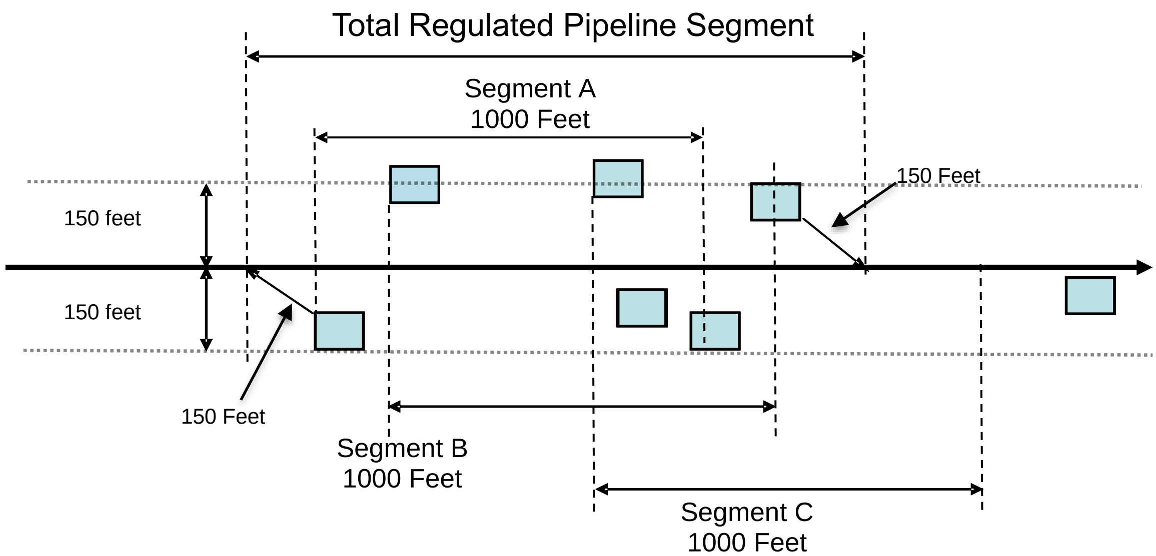

FIGURE 192.8B

2.3 Gathering lines that are not regulated.

(a) A gathering line is not regulated if any one of the following applies.

(1) Operates at less than 0 psig (§192.1(b)(4)(i)).

(2) Lies in a Class 1 location (§192.8), unless included in a safety buffer.

(3) Is a Type B gathering line within a Class 2 location where the operator uses the optional methodology for either Area 2(b) or Area 2(c) and the number of dwellings is below the minimum criteria.

(i) The operator may choose to use method 2(a), 2(b), or 2(c). If the operator determines, by using any of the three methods, that an onshore gathering line or a segment of an onshore gathering line is not regulated, no further action is required.

(ii) The operator may use one method for an onshore gathering line or a segment of an onshore gathering line and then use a different method for another onshore gathering line or segment of an onshore gathering line.

Note: Operators should retain records of the determination process used and the conclusions reached.

(b) An onshore gathering line within the inlets of the Gulf of Mexico is not required to meet any requirements, except for those addressed in §192.612 (see §192.1(b)(4)(iii)).

3 FLOW CHART

The following flow chart (Figure 192.8C) is to assist operators in identifying the type of gathering line and the requirements to be followed for that type of line.

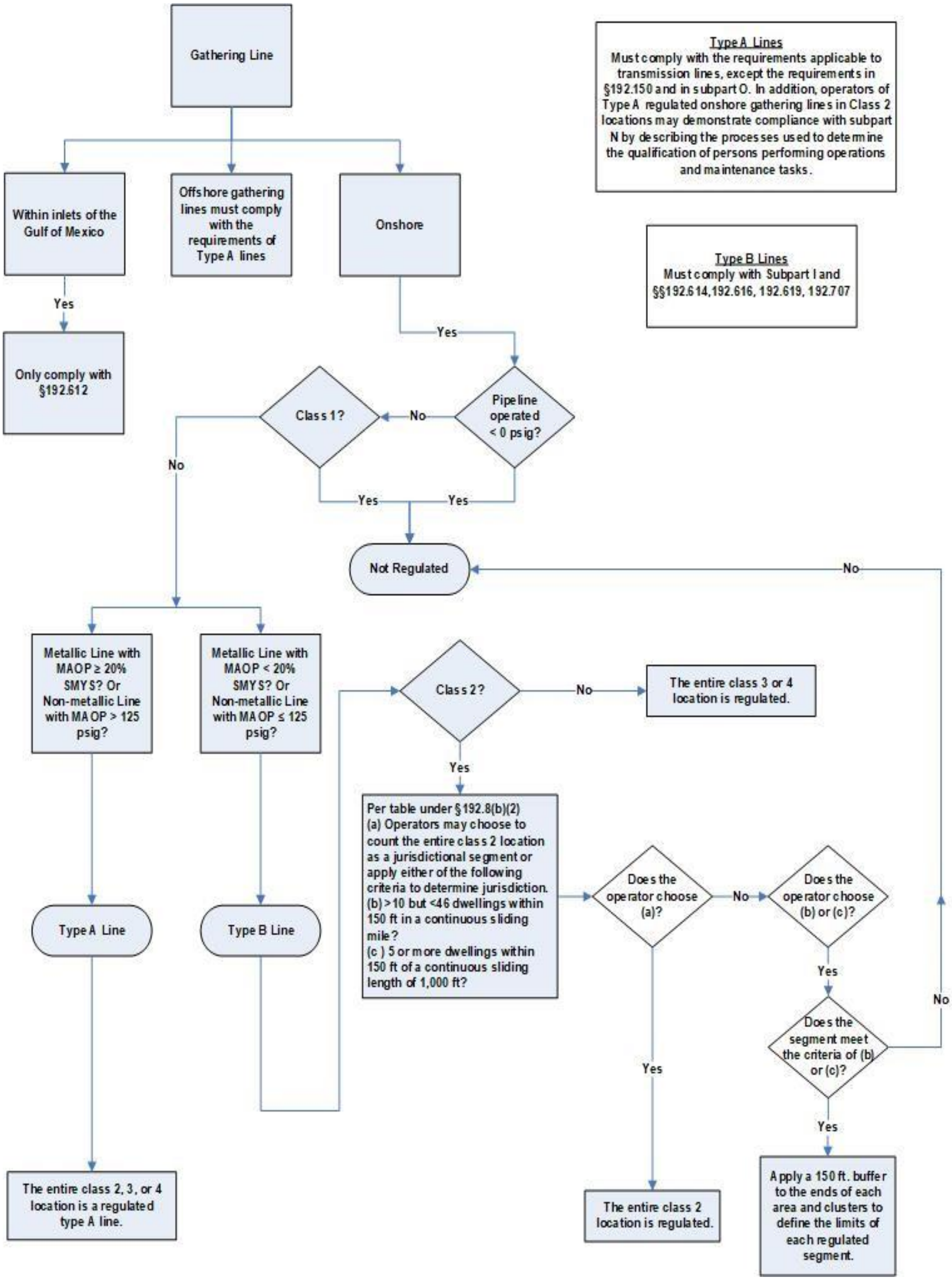

FIGURE 192.8C

§192.9

What requirements apply to gathering pipelines?

[Effective Date: 05/24/23]

(a) *Requirements.* An operator of a gathering line must follow the safety requirements of this part as prescribed by this section.

(b) *Offshore lines.* An operator of an offshore gathering line must comply with requirements of this part applicable to transmission lines, except the requirements in §§ 192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c),192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part.

(c) *Type A lines.* An operator of a Type A regulated onshore gathering line must comply with the requirements of this part applicable to transmission lines, except the requirements in §§192.13(d), 192.150, 192.285(e), 192.319(d) through (g), 192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), 192.493, 192.506, 192.607, 192.613(c), 192.619(e), 192.624, 192.710, 192.712, and 192.714 and in subpart O of this part. However, an operator of a Type A regulated onshore gathering line in a Class 2 location may demonstrate compliance with subpart N of this part by describing the processes it uses to determine the qualification of persons performing operations and maintenance tasks.

(d) *Type B lines.* An operator of a Type B regulated onshore gathering line must comply with the following requirements:

(1) If a line is new, replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with requirements of this part applicable to transmission lines. Compliance with §§ 192.67, 192.127, 192.179(e) and (f), 192.205, 192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(2) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except the requirements in §§192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493.

(3) If the pipeline contains plastic pipe or components, the operator must comply with all applicable requirements of this part for plastic pipe components;

(4) Carry out a damage prevention program under §192.614;

(5) Establish a public education program under §192.616;

(6) Establish the MAOP of the line under §192.619(a), (b), and (c);

(7) Install and maintain line markers according to the requirements for transmission lines in §192.707; and

(8) Conduct leakage surveys in accordance with the requirements for transmission lines in §192.706 using leak detection equipment and promptly repair hazardous leaks that are discovered in accordance with §192.703(c).

(e) *Type C lines*. The requirements for Type C gathering lines are as follows.

(1) An operator of a Type C onshore gathering line with an outside diameter greater than or equal to 8.625 inches must comply with the following requirements:

(i) Except as provided in paragraph (h) of this section for pipe and components made with composite materials, the design, installation, construction, initial inspection, and initial testing of a new, replaced, relocated, or otherwise changed Type C gathering line, must be done in accordance with the requirements in subparts B through G and J of this part applicable to transmission lines. Compliance with §192.67, 192.127, 192.179(e) and (f), 192.205,192.227(c), 192.285(e), 192.319(d) through (g), 192.506, 192.634, and 192.636 is not required;

(ii) If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines except for §§192.461(f) through (i), 192.465(d) and (f), 192.473(c), 192.478, 192.485(c), and 192.493;

(iii) Carry out a damage prevention program under §192.614;

(iv) Develop and implement procedures for emergency plans in accordance with

§192.615;

(v) Develop and implement a written public awareness program in accordance with §192.616;

(vi) Install and maintain line markers according to the requirements for transmission lines in §192.707; and

(vii) Conduct leakage surveys in accordance with the requirements for transmission lines in §192.706 using leak-detection equipment, and promptly repair hazardous leaks in accordance with §192.703(c).

(2) An operator of a Type C onshore gathering line with an outside diameter greater than 12.75 inches must comply with the requirements in paragraph (e)(1) of this section and the following:

(i) If the pipeline contains plastic pipe, the operator must comply with all applicable requirements of this part for plastic pipe or components. This does not include pipe and components made of composite materials that incorporate plastic in the design; and

(ii) Establish the MAOP of the pipeline under §192.619(a) or (c) and maintain records used to establish the MAOP for the life of the pipeline.

(f) *Exceptions.* (1) Compliance with paragraphs (e)(1)(ii),(v),(vi), and (vii) and (e)(2)(i) and (ii) of this section is not required for pipeline segments that are 16 inches or less in outside diameter if one of the following criteria are met:

(i) *Method 1*. The segment is not located within a potential impact circle containing a building intended for human occupancy or other impacted site. The potential impact circle must be calculated as specified in §192.903, except that a factor of 0.73 must be used instead of 0.69. The MAOP used in this calculation must be determined and documented in accordance with paragraph (e)(2)(ii) of this section.

(ii) *Method 2.* The segment is not located within a class location unit (see §192.5) containing a building intended for human occupancy or other impacted site.

(2) Paragraph (e)(1)(i) of this section is not applicable to pipeline segments 40 feet or shorter in length that are replaced, relocated, or changed on a pipeline existing on or before May 16, 2022.

(3) For purposes of this section, the term "building intended for human occupancy or other impacted site" means any of the following:

(i) Any building that may be occupied by humans, including homes, office buildings factories, outside recreation areas, plant facilities, etc;

(ii) 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); or

(iii) 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.

(g) *Compliance deadlines.* An operator of a regulated onshore gathering line must comply with the following deadlines, as applicable.

(1) An operator of a new, replaced, relocated, or otherwise changed line must be in compliance with the applicable requirements of this section by the date the line goes into service, unless an exception in §192.13 applies

(2) If a Type A or Type B regulated onshore gathering pipeline existing on April 14, 2006, was not previously subject to this part, an operator has until the date stated in the second column to comply with the applicable requirement for the pipeline listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

Requirement	Compliance deadline
(i) Control corrosion according to requirements for transmission lines in subpart I of this part.	**April 15, 2009**
(ii) Carry out a damage prevention program under §192.614.	**October 15, 2007**

Requirement	Compliance deadline
(iii) Establish MAOP under §192.619.	**October 15, 2007**
(iv) Install and maintain line markers under §192.707.	**April 15, 2008**
(v) Establish a public education program under §192.616	**April 15, 2008**
(vi) Other provisions of this part as required by paragraph (c) of this section for Type A lines.	**April 15, 2009**

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

(4) If a Type C gathering pipeline existing on or before May 16, 2022, was not previously subject to this part, an operator must comply with the applicable requirements of this section, except for paragraph (h) of this section, on or before:

(i) May 16, 2023; or

(ii) An alternative deadline approved by PHMSA. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of the deadline in paragraph (b)(1) of this section. The notification must be made in accordance with §192.18 and must include a description of the affected facilities an operating environment, the proposed alternative deadline for each affected requirement, the proposed alternative deadline for each affected requirement, the justification for each alternative compliance deadline, and actions the operator will take to ensure the safety of affected facilities.

(5) If, after May 16, 2022, a change in class location, an increase in dwelling density, or an increase in MAOP causes a pipeline to become a Type C gathering pipeline, or causes a Type C gathering pipeline to become subject to additional Type C requirements (*see* paragraph (f) of this section), the operator has 1 year after the pipeline becomes subject to the additional requirements to comply with this section.

(h) *Composite materials*. Pipe and components made with composite materials not otherwise authorized for use under this part may be used on Type C gathering pipelines if the following requirements are met:

(1) Steel and plastic pipe and components must meet the installation, construction, initial inspection, and initial testing requirements in subpart B through G and J of this part applicable to transmission lines.

(2) Operators must notify PHMSA in accordance with §192.18 at least 90 days prior to installing new or replacement pipe or components made of composite materials otherwise not authorized for use under this part in a Type C gathering pipeline. The notifications required by this section must include a detailed description of the pipeline facilities in which pipe or components made of composite materials would be used, including:

(i) The beginning and end points (stationing by footage and mileage with latitude and longitude coordinates) of the pipeline segment containing composite pipeline material and the counties and States in which it is located;

(ii) A general description of the right-of-way including high consequence areas, as defined in §192.905;

(iii) Relevant pipeline design and construction information including the year of installation, the specific composite material, the diameter, wall thickness, and any manufacturing and construction specifications for the pipeline;

(iv) Relevant operating information, including MAOP, leak and failure history, and the most recent pressure test (identification of the actual pipe tested, minimum and maximum test pressure, duration of test, any leaks and any test logs and charts) or assessment results;

(v) An explanation of the circumstances that the operator believes make the use of composite pipeline material appropriate and how the design, construction, operations, and maintenance will mitigate safety and environmental risks;

(vi) An explanation of procedures and tests that will be conducted periodically over the life of the composite pipeline material to document that its strength is being maintained;

(vii) Operations and maintenance procedures that will be applied to the alternative materials. These include procedures that will be used to evaluate and remediate anomalies and how the operator will determine safe operating pressures for composite pipe when defects are found;

(viii) An explanation of how the use of composite pipeline material would be in the public interest; and

(ix) A certification signed by a vice president (or equivalent or higher officer) of the operator's company that operation of the applicant's pipeline using composite pipeline material would be consistent with pipeline safety.

(3) Repairs or replacements using materials authorized under this part do not require notification under this section.

[Amdt. 192-72, 59 FR 17275, Apr. 12, 1994 with Amdt. 192-72 Ext., 59 FR 49896, Sept. 30, 1994, Amdt. 192-72 Ext. Correction, 59 FR 52863, Oct. 19, 1994 and Amdt. 192-72 Ext., 60 FR 7133, Feb. 7, 1995; Amdt. 192-95, Correction & Petition for Reconsideration, 69 FR 18228, Apr. 6, 2004; Amdt. 192-102, 71 FR 13289, Mar. 15, 2006; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015; Amdt 192-124, 83 FR 58694, Nov. 20, 2018; Amdt 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

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

(a) See §192.1 for gathering lines excluded from the provisions of Part 192. Also, see the "Glossary of Commonly Used Terms" under §192.3 for definition of "*Otherwise changed*."
(b) See Guide Material Appendix G-192-22

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

GUIDE MATERIAL

No guide material necessary.

§192.11
Petroleum gas systems.

[Effective Date: 08/06/15]

(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 of 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.

[Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-119, 80 FR 168, Jan. 5, 2015 with Amdt. 192-119 Correction, 80 FR 46847, Aug. 6, 2015]

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).

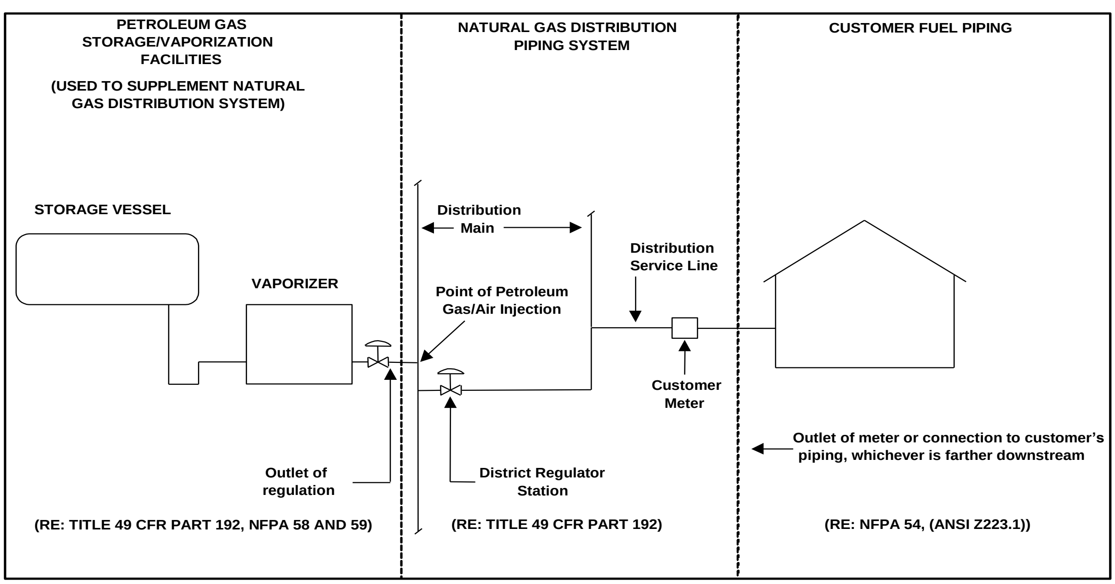

FIGURE 192.11A

§192.13

What general requirements apply to pipelines regulated under this part?

[Effective Date: 05/24/23]

(a) No person may operate a segment of pipeline listed in the first column of paragraph (a)(3) of this section 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.

(3) The compliance deadlines are as follows:

Pipeline	Date
(i) Offshore gathering pipeline.	July 31, 1977.
(ii) Regulated onshore gathering pipeline to which this part did not apply until April 14, 2006.	March 15, 2007.
(iii) Regulated onshore gathering pipeline to which this part did not apply until May 16, 2022	May 16, 2023.
(iv) All other pipelines.	March 12, 1971.

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

Pipeline	Date
(1) Offshore gathering pipeline.	July 31, 1977.
(2) Regulated onshore gathering line to which this part did not apply until April 14, 2006.	March 15, 2007.
(3) Regulated onshore gathering line to which this part did not apply until May 16, 2022.	May 16, 2023.
(4) All other pipelines.	November 12, 1970.

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

(d) Each operator of an onshore gas transmission pipeline must evaluate and mitigate, as necessary, significant changes that pose a risk to safety or the environment through a management of change process. Each operator of an onshore gas transmission pipeline must develop and follow a management of change process, as outlined in ASME/ANSI B31.8S, section 11 (incorporated by reference, *see* § 192.7), that addresses technical, design, physical, environmental, procedural, operational, maintenance, and organizational changes to the pipeline or processes, whether permanent or temporary. A management of change process must include the following: reason for change, authority for approving changes, analysis of implications, acquisition of required work permits, documentation, communication of change to affected parties, time limitations, and qualification of staff. For pipeline segments other than those covered in subpart O of this part, this management of change process must be implemented by February 26, 2024. The requirements of this paragraph (d) do not apply to gas gathering pipelines. Operators may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024 in accordance with § 192.18. The notification must include a

reasonable and technically justified basis, an up-to-date plan for completing all actions required by this section, the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; Amdt. 192-102, 71 FR 13289, Mar. 15, 2006; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

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.

[Issued by Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

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) Material and tensile tests. See Appendix B to Part 192.
(e) Internal inspections.
(f) Radiographic inspections.
(g) Pressure tests. See §192.619.

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.
(g) Population density.

4 REGULATORY DOCUMENTS

For pipelines being converted under this section, the operator should review it's procedural manual for operations, maintenance, and emergencies and its public education program for compliance to Part 192 prior to placing the converted line into a natural gas service.

§192.15

Rules of regulatory construction.

[Effective Date: 11/12/70]

(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.

[Effective Date: 05/04/98]

(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.

[Issued by Amdt. 192-74, 60 FR 41821, Aug. 14, 1995 with Amdt. 192-74 Correction, 60 FR 43028, Aug.18, 1995 and Amdt. 192-74A, 60 FR 63450, Dec. 11, 1995; Amdt. 192-84, 63 FR 7721, Feb. 17, 1998 with Amdt. 192-84 Confirmation, 63 FR 38757, July 20, 1998 and Amdt. 192-84 Correction, 63 FR 38758, July 20, 1998]

GUIDE MATERIAL

No guide material necessary.

§192.18

How to notify PHMSA.

[Effective Date: 05/24/23]

(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 an operator submits, pursuant to § 192.8, § 192.9, § 192.13, § 192.179, § 192.319, § 192.461, § 192.506, § 192.607, § 192.619, § 192.624, § 192.632, § 192.634, § 192.636, § 192.710, § 192.712, § 192.714, § 192.745, § 192.917, § 192.921, § 192.927, § 192.933, or § 192.937 a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* "other technology" or "alternative equivalent technology") than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety informing the operator that PHMSA objects to the proposal, or that PHMSA requires additional time and/or more information to conduct its review.

[Issued by Amdt. 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

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

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leakage. If it is to be welded, steel pipe that has not been manufactured to a listed specification must also pass the weldability tests prescribed in paragraph II-B of Appendix B to this part.

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

(e) New steel pipe that has been cold expanded must comply with the mandatory provisions of API Spec 5L (incorporated by reference, *see* §192.7).

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-12, 38 FR 4760, Feb. 22, 1973; Amdt. 192-51, 51 FR 15333, Apr. 23, 1986; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-119, 80 FR 168, Jan. 5, 2015 with Amdt. 192-119 Correction, 80 FR 46847, Aug. 6, 2015]

GUIDE MATERIAL

Listed specifications are shown in Section I of Appendix B. The user is cautioned that there may be more recent editions of some of these specifications than those approved and listed in Section I of Appendix B.

§192.57
(Removed and reserved.)

[Effective Date: 03/08/89]

§192.59
Plastic pipe.

[Effective Date: 01/22/19]

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

(1) It is manufactured in accordance a listed specification;

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

(3) It is free of visible defects

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

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

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

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

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

(5) It is free of visible defects.

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

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

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

(d) Rework and/or regrind material is not allowed in plastic pipe produced after March 6, 2015 used under this part.

[Amdt. 192-19, 40 FR 10471, Mar. 6, 1975; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

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

Each operator should establish that new or used pipe complies with the requirements of the applicable ASTM piping specification (referenced in §192.7) for the type of plastic pipe, such as ASTM D2513 for polyethylene (PE), ASTM F2945 for polyamide 11 (PA11), ASTM F2785 for polyamide 12 (PA12), or ASTM D2517 for thermosetting plastics by one of the following methods.

(a) Inspection and testing by an accredited laboratory with written certification.
(b) Inspection and testing by the user.
(c) Written certification from the manufacturer at the time of purchase. Included as part of this certification should be copies of the production quality control records referenced by lot and shift numbers.

§192.61

(Removed and reserved.)

[Effective Date: 03/08/89]

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.

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

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

1 STORAGE

(a) The resistance of plastic pipe to deterioration from UV exposure can vary greatly. Except for ASTM D2517 “Reinforced Epoxy Resin Gas Pressure Pipe and Fittings”, the plastic pipe standards incorporated by reference in §192.7 address outdoor storage. For ASTM D2517, the operator should request the manufacturer of the plastic pipe to provide a written statement specifying the time the product can be stored outside without loss of properties that qualify it for buried gas piping application. Regardless of the plastic pipe used, the operator should ensure that the UV exposure time is not exceeded.

(b) When storing outdoors, cumulative exposure periods should be considered. The Pipe Production Code marked on the pipe includes the date of manufacture. In general, most manufacturers store pipe outdoors prior to shipment, and allowance for this period should be made. Exposure time can be minimized by issuing from storage on a "first-in, first-out" rotation, with the date of manufacture used as a control. The pipe with the earliest date of manufacture should be issued first for installation.

(c) To limit UV exposure time and prevent degradation, plastic pipe may be stored indoors away from UV exposure or outdoors with a protective cover.

(d) Plastic materials vary in their ability to resist damage from fire, heat, and chemicals. Care should be exercised at all times to protect the pipe from these hazards.

(e) Fittings, riser and other components should be stored in a manner which limits UV exposure and helps preserve the adhesion of marking labels until time of installation.

(f) For limitations and considerations on the use of plastic pipe temporarily installed above ground, see guide material under §192.321.

2 HANDLING

(a) When handling plastic pipe.
 (1) Use proper slings or other non-abrasive lifting equipment when loading and unloading pipe.
 (2) Avoid rough handling especially at low temperatures which can fracture thermoplastic pipe if subjected to significant impact or shock loads.
 (3) Avoid dropping or striking the pipe with handling equipment, tools, or other objects.
 (4) Avoid pushing or pulling over sharp projections.
 (5) Prevent kinking or buckling. Any kinks or buckles that occur should be cut out as a cylinder.

(b) The impact and ductility properties of plastics should be evaluated when the material is intended for use in facilities subjected to low temperatures. Lower temperatures will affect thermoplastic pipe by increasing stiffness and vulnerability to impact damage.

(c) For coiled pipe, lower temperatures will require more effort to uncoil the pipe, and it can spring back forcibly if the ends are not anchored or restrained. The forceful movement of the loose pipe ends becomes more pronounced in cold weather and personnel should be aware of this for their own safety. Extra precautions should be taken when installing larger-diameter coiled pipe (>3-inch) in cold temperature conditions. The manufacturer of straightening and re-rounding equipment should be consulted for recommendations regarding low-temperature equipment operation.

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SUBPART C
PIPE DESIGN

§192.101
Scope.
[Effective Date: 11/12/70]

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

GUIDE MATERIAL

No guide material necessary.

§192.103
General.
[Effective Date: 11/12/70]

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

GUIDE MATERIAL

1 GENERAL

The minimum wall thickness for pressure containment as calculated under §192.105 may not be adequate to withstand other forces to which the pipeline may be subjected. Consideration should be given to stresses associated with transportation, handling the pipe during construction, weight of water during testing, buoyancy, geotechnical, or geological forces, and other secondary loads that may occur during construction, operation, or maintenance. Consideration should also be given to welding or mechanical joining requirements.

2 NON-STEEL PIPE

The minimum wall thickness for materials other than steel pipe are prescribed elsewhere in Part 192. See §§192.123 and 192.125.

3 REFERENCES

See Guide Material Appendix G-192-13 for design considerations. Numerous references are available for the calculation of external forces on pipelines. Methods include reliance on experience, empirical formula, and finite element analysis. A partial listing of references follows.

(a) API RP 5L1, "Recommended Practice for Railroad Transportation of Line Pipe" (see §192.7 for IBR).

(b) API RP 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels" (see §192.7 for IBR).
(c) API RP 1102, "Steel Pipelines Crossing Railroads and Highways."
(d) API RP 1117, "Movement of In-Service Pipelines."
(e) ASCE 428-5, "Guidelines for the Seismic Design of Oil and Gas Pipeline Systems" (Discontinued).
(f) GRI-91/0283, "Guidelines for Pipelines Crossing Railroads."
(g) GRI-91/0284, "Guidelines for Pipelines Crossing Highways."
(h) PRCI L52292, "Guidelines for Constructing Pipelines Through Areas Prone to Landslide and Subsidence Hazards."

§192.105
Design formula for steel pipe.
[Effective Date: 07/13/98]

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

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

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

S **= Yield strength in pounds per square inch (kPa) determined in accordance with §192.107.**

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

t **= Nominal wall thickness of the pipe in inches (millimeters). If this is unknown, it is determined in accordance with §192.109. Additional wall thickness required for concurrent external loads in accordance with §192.103 may not be included in computing design pressure.**

F **= Design factor determined in accordance with §192.111.**

E **= Longitudinal joint factor determined in accordance with §192.113.**

T **= Temperature derating factor determined in accordance with §192.115.**

(b) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75 percent of the pressure determined under paragraph (a) of this section if the temperature of the pipe exceeds 900 ºF (482 ºC) at any time or is held above 600 ºF (316 ºC) for more than 1 hour.

[Amdt. 192-47, 49 FR 7567, Mar. 1, 1984; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 WALL THICKNESS

The nominal wall thickness (t) should not be less than that determined by the considerations given in the guide material under §192.103.

§192.123

[Removed and Reserved]

[Effective Date: 01/22/19]

[Amdt. 192-31, 43 FR 13880, Apr. 3, 1978; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE26, 73 FR 79002, Dec. 24, 2008; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

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

1 IMPACT AND DUCTILITY

(Note: This guide material was moved to §192.69.)

2 PETROLEUM GASES

The pressure-temperature relationship with petroleum gases should be such that condensation will not occur when using PE piping.

3 HOT TAPS

(a) When making a hot-plate saddle fusion on PE pipelines, the probability of a blowout increases with an increase in pressure or a decrease in wall thickness. This should be considered, particularly when performing hot-plate saddle fusion on PE pipelines as follows: 1-inch and 1¼-inch pipe with an SDR greater than 10, and 2-inch, 3-inch, and 4-inch pipe with an SDR greater than 11. Where this is a concern, the pipeline pressure may need to be reduced during such fusions. Alternatively, a heavier-wall thickness could be used than that required by the pressure design formula. See PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."
(b) Electrofusion tapping tees may be used as an alternate to hot-plate, fusion tapping tees to reduce the probability of blowouts when hot tapping PE pipes. The manufacturer of the electrofusion fitting should be contacted for recommendations.
(c) Mechanical tapping tees may be used as an alternative to heat-fusion tapping tees to avoid the possibility of blowouts when tapping PE pipes.

4 EFFECTS OF LIQUID HYDROCARBONS

4.1 General.

Liquid hydrocarbons such as gasoline, diesel fuel, and condensates, either inside the pipe or in the surrounding soil, are known to have a detrimental effect on PE and PVC plastic piping materials. PA 11 piping is not affected by liquid hydrocarbons. Contact the piping manufacturer for specific recommendations.

4.2 Effect on design pressure (see §192.121).

(a) If thermoplastic materials covered by ASTM D2513 (see §192.7 for IBR) are to be exposed continuously to liquid hydrocarbons, it is recommended that the design pressure be de-rated in accordance with the following formula. See 4.3 below for references on this subject.

$$P_{de\text{-}rated} = P_{\S 192.121} \times DF_C$$

Where:

$P_{de\text{-}rated}$ = De-rated design pressure, gauge, psig (kPa).
$P_{\S 192.121}$ = Design pressure, gauge, psig (kPa) determined under §192.121.
DF_C = Chemical Design Factor determined in accordance with Table 192.123i.

Pipe Material	Chemical Design Factor
PA (polyamide)	1.00
PE (polyethylene)	0.50
PVC (polyvinyl chloride)	0.50

TABLE 192.123i

(b) If PE or PVC pipe is to be exposed intermittently to liquid hydrocarbons, the pipe manufacturer should be consulted to determine the appropriate DF_C.

4.3 References.

(a) PA pipe.
   (1) "An Evaluation of Polyamide 11 for Use in High Pressure/High Temperature Gas Piping Systems," T.J. Pitzi et al., 15th Plastic Fuel Gas Pipe Symposium Proceedings - 1997, p. 107.
   (2) "Polyamide 11 Liners Withstand Hydrocarbons, High Temperature," A. Berry, Pipeline & Gas Journal, December 1998, p. 81.
(b) PE pipe.
   (1) PPI TR-9, "Recommended Design Factors and Design Coefficients for Thermoplastic Pressure Pipe."
   (2) PPI TR-22, "Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases."
   (3) "Mechanical Integrity of Fusion Joints Made from Polyethylene Pipe Exposed to Heavy Hydrocarbons," S.M. Pimputkar, 14th Plastic Fuel Gas Pipe Symposium Proceedings - 1995, p. 141.
   (4) "Strength of Fusion Joints Made from Polyethylene Pipe Exposed to Heavy Hydrocarbons," S.M. Pimputkar, 15th Plastic Fuel Gas Pipe Symposium Proceedings - 1997, p. 309.
   (5) GRI 96/0194, "Service Effects of Hydrocarbons on Fusion and Mechanical Performance of Polyethylene Gas Distribution Piping."
(c) PVC pipe.
   "Prediction of Organic Chemical Permeation through PVC Pipe," A.R. Berens, Research Technology, November 1985, p. 57.

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

[Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

For the definition of the bottle-type holder, see guide material under §§192.3 and 192.175.

§192.179
Transmission line valves.

[Effective Date: 10/05/2022]

(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:

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

(2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve.

(3) Each point on the pipeline in a Class 2 location must be within 7½ miles (12 kilometers) of a valve.

(4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.

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

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

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

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

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

(e) For onshore transmission pipeline segments with diameters greater than or equal to 6 inches that are constructed after April 10, 2023, the operator must install rupture-mitigation valves (RMV) or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g). All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of §§192.634 and 192.636. Exempted from this paragraph's installation requirements are pipelines segments in Class 1, or Class 2 locations that have a potential impact radius (PIR), as defined in §192.903, of 150 feet or less. An operator may request an extension of the installation compliance deadlines requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in § 192.18, that those installation

compliance deadlines would be economically, technically, or operationally, infeasible for a particular new pipeline.

(f) For entirely replaced onshore transmission pipeline segments, as defined in § 192.3, with diameters greater than or equal to 6 inches and that are installed after April 10, 2023, the operator must install RMVs or an alternative equivalent technology whenever a valve must be installed to meet the appropriate valve spacing requirements of this section. An operator seeking to use alternative equivalent technology must notify PHMSA in accordance with the procedures set forth in paragraph (g) of this section. All RMVs and alternative equivalent technologies installed pursuant to this paragraph must meet the requirements of §§192.634 and 192.636. The requirements of this paragraph apply when the applicable pipeline replacement project involves a valve, either through addition, replacement, or removal. This paragraph's installation requirements do not apply to pipe segments in Class 1 or Class 2 locations that have a PIR, as defined in §192.903, that is less than or equal to 150 feet. An operator may request an extension of the installation compliance deadline requirements of this paragraph if it can demonstrate to PHMSA, in accordance with the notification procedures in §192.18, that those installation compliance deadlines would be economically, technically, or operationally infeasible for a particular pipeline replacement project.

(g) If an operator elects to use alternative equivalent technology in accordance with paragraphs (e) or (f) of this section, the operator must notify PHMSA in accordance with the procedures in §192.18. The operator must include a technical and safety evaluation in its notice to PHMSA. Valves that are installed as alternative equivalent technology must comply with §§ 192.634 and 192.636. An operator requesting use of manual valves as an alternative equivalent technology must also include within the notification submitted to PHMSA a demonstration that installation of an RMV as otherwise required would be economically, technically, or operationally infeasible. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, and use of such valve would not require a notification to PHMSA in accordance with § 192.18, but it must comply with § 192.636.

(h) The valve spacing requirements of paragraph (a) of this section do not apply to pipe replacements on a pipeline if the distance between each point on the pipeline and the nearest valve does not exceed:

(1) Four (4) miles in Class 4 locations, with a total spacing between valves no greater than 8 miles;

(2) Seven-and-a-half (7½) miles in Class 3 locations, with a total spacing between valves no greater than 15 miles; or

(3) Ten (10) miles in Class 1 or 2 locations, with a total spacing between valves no greater than 20 miles.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

GUIDE MATERIAL

1 VALVE SPACING ON OFFSHORE-ONSHORE PIPELINES

(a) Where the distance between valves on a combined segment of a new offshore-onshore pipeline exceeds the valve spacing requirements for onshore pipelines, consideration should be given to the installation of a block valve at the nearest practical location to the land juncture of the pipeline segment.

(b) Sectionalizing block valves and blowdown valves associated with Type A and Type B gathering lines might need to be installed or relocated when any portion of a line is replaced, relocated, or otherwise changes.

(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 manufacturing standard and pressure rating to which each valve was 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 and with nominal diameters of 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.

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

GUIDE MATERIAL

(a) Records for pipeline components installed in steel transmission and Type A gathering lines should be traceable, verifiable, and complete to establish or confirm the MAOPs. The records requirements of §192.205 are not applicable for Type B or C gathering lines (§192.9).

(b) Records may include the following.

- (1) Mill test reports, which might have the following data.
  - (i) Heat numbers.
  - (ii) Steel chemistry.
  - (iii) Yield strength.
  - (iv) Ultimate tensile strength.
  - (v) Pipe grade.
  - (vi) Pipe wall thickness
  - (vii) Manufacturing process.
- (2) Purchase requisitions and orders.

(3) Bills of lading.
(4) Pressure test records and test procedure documentation.
(5) Pressure rating documentation.
(6) Manufacturing standard(s) documentation.
(7) Manufacturing inspection records.
(8) Coating documentation.
(9) GPS or survey coordinates for the location of installed components.
(10) Construction inspection notes and photographs related to field installation of pipeline components.

(c) Records may be maintained at a central location or at multiple locations for the operational life of the components.

(d) Records may be maintained as paper copies, electronically, or in any other appropriate format.

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maximum scour and outside the limits of lateral channel migration.

(d) Where transmission lines or mains cross areas that are not normally under water, but are subject to periodic run-off, the depth should be sufficient to protect the pipeline from expected scour (washout), such as that expected from a 100-year flood. Concrete coating, protective mats, or other means can be used to protect the pipeline from damage that may result from scouring action.

(e) Access to isolation valves should be designed considering water elevations during a 100-year flood event. This can be accomplished by placing the valves above the 100-year flood elevation, behind levees, or by using valve extensions and access platforms.

2 PLATFORM PIPING AND RISERS (§192.317(c))

(a) Whenever feasible, platform piping below the lowest deck level should be located inboard of the vertical plane established by the intersection of the outermost structural members of the platform and the high water level.

(b) Whenever feasible, pipe risers should be located along faces of a platform other than those where boat landings are provided. Additional protection may be afforded by the installation of boat bumpers or encasement. When risers are installed on facings of a platform where boat landings are located, they should be located inboard of the boat landing or otherwise protected by bumpers or framework comparable in mechanical strength to the boat landing. When pipe risers 6 inches and smaller in size are installed, consideration should be given to furnishing additional protection in the proximity of the water line by installation of a structural member of greater mechanical strength.

3 CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

3.1 Onshore.

See Guide Material Appendix G-192-13.

3.2 Offshore.

When designing and constructing offshore pipelines, consideration should be given to the placement of subsea taps, valves, bypasses, and other appurtenances to avoid or mitigate damage from anchors, nets, etc. It should be recognized that other federal and state agencies have established regulations that can affect the design and construction of offshore pipelines.

4 CONSIDERATIONS TO MINIMIZE DAMAGE BY BLASTING OPERATIONS

See Guide Material Appendix G-192-16.

5 CONSIDERATIONS TO MINIMIZE DAMAGE BY EXTERNAL CORROSION FROM STRAY ELECTRICAL CURRENTS

See guide material under §192.473.

§192.319

Installation of pipe in a ditch.

[Effective Date: 05/24/23]

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

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

(1) Provides firm support under the pipe; and

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

(c) All offshore pipe in water at least 12 feet (3.7 meters) deep but not more than 200 feet (61 meters) deep, as measured from the mean low tide, except pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water, must be installed so that the top of the pipe is below the natural bottom unless the pipe is supported by stanchions, held in place by anchors or heavy concrete coating, or protected by an equivalent means. Pipe in the Gulf of Mexico and its inlets under 15 feet (4.6 meters) of water must be installed so that the top of the pipe is 36 inches (914 millimeters) below the seabed for normal excavation or 18 inches (457 millimeters) for rock excavation.

(d) Promptly after a ditch for an onshore steel transmission line is backfilled (if the construction project involves 1,000 feet or more of continuous backfill length along the pipeline), but not later than 6 months after placing the pipeline in service, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(e) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (d) of this section.

(f) An operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, see § 192.7) within 6 months after the pipeline is placed in service, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(g) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (d) through (f) of this section.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

1 INSTALLATION

1.1 General considerations.

On pipelines operating at stresses of 20% or more of the specified minimum yield strength, it is important that stresses induced into the pipeline by construction be minimized. The pipe should fit the ditch without the use of external force to hold it in place until the backfill is completed. Periodic placement of sandbags, plastic foam benches, etc., along the bottom of the ditch is one effective means of providing firm support and minimizing construction stresses.

When long sections of pipe that have been welded alongside the ditch are lowered in, or where excessive depths are encountered, care should be taken to avoid jerking the pipe or imposing any strains that might kink or put a permanent bend in the pipe. Where these conditions are encountered, the use of slack loops should be considered.

1.2 Surf zones.

In surf zones, special consideration should be given to maintaining the position of the pipe under anticipated conditions of buoyance and water motion. This may be accomplished by the following means.

(a) Burying the pipe at a greater depth below the natural bottom.
(b) Using weight coatings.
(c) Using anchors.

1.3 Inspections.

(a) Onshore.

(1) The condition of the ditch bottom should be inspected just before the pipe is lowered-in.

(2) The surface of the coated pipe should be inspected as the pipe is lowered into the ditch. Coating lacerations indicate that the pipe may have been damaged after the coating was applied.

(3) The fit of the pipe to the ditch should be inspected before backfilling.

(b) Offshore.

(1) The surface of the corrosion preventive coating should be inspected before weight-coating.

(2) The weight-coating should be inspected before the pipe is welded.

2 JOINT RESTRAINT

2.1 Harnessing or buttressing.

Suitable harnessing or buttressing should be provided at points where the pipe deviates from a straight line and the thrust, if not restrained, would separate the joints.

2.2 Special considerations.

Cast iron pipe installed in unstable soils should be provided with suitable supports. See Guide Material Appendix G-192-18.

3 BACKFILLING

3.1 General.

Backfilling should be performed in a manner to provide firm support under the pipe.

3.2 Backfill material.

(a) General. If there are large rocks in the material to be used for backfill, care should be used to prevent damage to the coating. This may be accomplished by the use of abrasion protection material (e.g., rock shield) or by making an initial fill with enough rock-free material to prevent damage.

(b) Effects on cathodic protection (CP) system. Consideration should be given to the possible CP current shielding effects that may occur from the installation of non-conductive materials, such as abrasion protection.

3.3 Abrasion Protection.

Where an abrasion protection material is used to prevent coating damage, it must be installed properly. One method of installing a wrap-type material is to secure it entirely around the pipe using fiberglass tape or other suitable banding material. The material should not be draped over the pipe unless suitable backfill and padding is placed in the ditch to provide continuous and adequate support of the pipe in the trench.

3.4 Consolidation.

If trench flooding is used to consolidate the backfill, care should be taken to see that the pipe is not floated from its firm bearing on the trench bottom. Where mains are installed in existing or proposed roadways or in unstable soil, flooding should be augmented by wheel rolling or mechanical compaction. Multi-lift mechanical compaction can be used in lieu of flooding.

3.5 Warning tape.

(a) After the pipe is installed in the ditch and backfilling has begun, consider placing a highly visible warning tape over the pipe to indicate the presence of a pipeline so that the warning tape is encountered first if someone excavates in the vicinity. The tape should be centered over the pipe for its entire length.

(b) The tape should be yellow to signify gas.

(c) A safety warning or message, such as “Warning: Buried Gas Pipeline”, should be imprinted on the tape.

(d) An operator should consider using warning tape for new installations and anytime existing pipe is exposed.

(e) When an operator is installing multiple pipelines within the same right-of-way, the same decision should be made on using warning tape for each of the newly installed pipelines.

4 DAMAGE PREVENTION

(a) Consider temporarily marking facilities during installation with paint, flags, or other means to help prevent damage in areas where continued construction is expected. This includes pipelines that are not energized.
(b) Check for and remove previous markings that might confuse others working around the facilities.

5 ALTERNATIVE INSTALLATION METHODS

5.1 Horizontal directional drilling.
(a) For damage prevention considerations while performing directional drilling or using other trenchless technologies, see Guide Material Appendix G-192-6.
(b) For additional considerations for horizontal directional drilling to install steel pipelines or plastic pipelines, see Guide Material Appendices G-192-15A and G-192-15B, respectively.

§192.321

Installation of plastic pipe.

[Effective Date: 01/22/19]

(a) Plastic pipe must be installed below ground level except as provided by paragraphs (g), (h), and (i) of this section.

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

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

(d) Plastic pipe must have a minimum wall thickness in accordance with § 192.121.

(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.

(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. Plastic pipe that is being encased must be protected from damage at all entrance and all exit points of the casing. The leading end of the plastic must be closed before insertion.

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

(1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less.

(2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage.

(3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.

(h) Plastic pipe may be installed on bridges provided that it is:

(1) Installed with protection from mechanical damage, such as installation in a metallic casing;

(2) Protected from ultraviolet radiation; and

(3) Not allowed to exceed the pipe temperature limits specified in §192.121.

(i) Plastic mains may terminate above ground level provided they comply with the following:

(1) The above-ground level part of the plastic main is protected against deterioration and external damage.

(2) The plastic main is not used to support external loads.

(3) Installations of risers at regulator stations must meet the design requirements of § 192.204.

[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

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

1 GENERAL PRECAUTIONS

1.1 Handling.
For guidance to protect pipe during handling, see guide material under §192.69

1.2 Considerations to minimize damage by outside forces.

See Guide Material Appendix G-192-13.

2 DIRECT BURIAL OF PLASTIC PIPE

2.1 Contraction.

The piping should be installed with sufficient slack to provide for possible contraction. Under high temperature conditions, cooling may be necessary before the last connection is made. See 3.5(f) of the guide material under §192.281.

2.2 Installation stress.

When long sections of piping that have been assembled alongside the ditch are lowered-in, care should be taken to avoid any strains that may overstress or buckle the piping, or impose excessive stress on the joints.

2.3 Backfilling.

(a) General. Blocking should not be used to support plastic pipe. Plastic pipe should be laid on undisturbed soil, well-compacted soil, well-tamped soil, or other continuous support. If plastic pipe is to be laid in soils that may damage it, the pipe should be protected by suitable rock-free materials.

(b) Backfill material. Backfilling should be performed in a manner to provide firm support around the piping and to protect the piping from damage. Plastic piping materials could be affected by rock impingement. The backfill expected to come in direct contact with the pipe should be free of rocks, pieces of pavement, or other materials that might damage the pipe. Rocks or similar material can cause stress concentrations that could limit the long-term performance of the piping system should pipe contact occur.

(1) Consult the pipe manufacturer for guidance to determine the appropriate backfill for its plastic piping material.

(2) Maximum particle size for materials within 6 inches of the pipe, including bedding materials and other initial materials that might damage the pipe, are shown in Table 192.321i.

Pipe Size	Maximum Particle Size (inch)
NPS 4 and smaller	1/2
NPS 6 and NPS 8	3/4
Larger than NPS 8	1

TABLE 192.321i

(3) Beyond the 6-inch zone, the final backfill should be free of materials that might damage the pipe, such as rocks (3 inches or larger), pieces of pavement, or construction debris. Additional guidance on backfill is provided in ASTM D2774, “Standard Practice for Underground Installation of Thermoplastic Pressure Piping.”

(c) Consolidation. If trench flooding is used to consolidate the backfill, care should be taken to see that the piping is not floated from its firm bearing on the trench bottom. Where mains and service lines are installed in existing or proposed roadways or in unstable soil, flooding should be augmented by wheel rolling or mechanical compaction. Multi-lift mechanical compaction can be used in lieu of flooding. Care should be taken when using mechanical compaction not to cause excessive ovality of the plastic pipe.

2.4 Means of locating.

(a) Tracer wire.

(1) A bare or coated corrosion-resistant metal wire may be buried along the plastic pipe. Wire size #12 or #14 AWG is commonly installed.

(2) Tracer wire may be installed physically separated from, or immediately adjacent to, the plastic pipe. Separation may lead to difficulty in accurately locating the plastic pipe. In determining placement of tracer wire relative to plastic pipe, the operator should consider the relative importance of locating the pipe versus potential pipe damage from a current surge through the tracer wire. Lightning strikes are a source of current surges.

(3) Tracer wire should not be wrapped around plastic pipe. It may be taped to the outside of the plastic pipe, especially for installation by boring or plowing-in, or placed loosely in the trench directly adjacent to the pipe.

(4) A separation of 2" to 6" between plastic pipe and tracer wire is commonly used where current surges, such as from lightning, have been experienced or can be expected.

(5) Leads from tracer wire into curb boxes and valve boxes and on outside service risers can be used for direct connection of locating instruments. Consideration should be given to ensuring that no bare tracer wire is exposed such that a lightning strike could cause a current surge through the wire.

(6) Splicing of tracer wire, if necessary, should be done in a manner to produce an electrically and mechanically sound joint that will not loosen or separate under conditions to which it may be subjected, such as backfilling operations and freeze-thaw cycles.

(7) Where the tracer wire is electrically connected to metallic structures (e.g., steel or cast iron pipe) for reasons such as expanded locating capabilities or cathodic protection, consideration should be given to the effects of electrical current surges on the ability to locate the plastic pipe or the increased potential for damage.

(8) Additional information may be obtained from AGA XR0603, "Plastic Pipe Manual for Gas Service."

(b) Metallic tape. A metallic coated or corrosion-resistant metallic tape may be installed along with the plastic pipe. Care should be taken so that the tape is not torn or separated during backfilling operations. Metallic locating tape normally has no accessible leads for connecting locating equipment, making it necessary to use a passive or induced current locating device.

(c) Mapping. Accurate mapping of plastic pipe with dimensions referenced to permanent landmarks (e.g., lot lines, street centerlines) is an acceptable method of locating plastic pipe.

(d) Passive devices. Tuned coils or other passive devices may be buried at strategic points along a plastic pipeline. These devices can be located from above ground by means of an associated locating instrument.

2.5 Warning tape.

Highly visible warning tape may be used in addition to one of the means for locating the pipe. Such tapes should be yellow with a safety warning or message, such as "Warning: Buried Gas Pipeline". Warning tapes are generally installed above the plastic pipe so that it will be encountered first by someone digging in the vicinity. For placing warning tape in a ditch, see 3.5 of the guide material under §192.319.

3 PLASTIC PIPE INSERTED INTO A CASING OR INTO AN ABANDONED PIPELINE

3.1 General.

(a) The casing or abandoned pipeline should be prepared to the extent necessary to remove any sharp edges, projections, dust, welding slag, or abrasive material which could damage the plastic during or after insertion.

(b) A support sleeve or plug should be used to prevent the plastic pipe from bearing on the end of the casing or abandoned pipeline.

(c) Maps or other records should indicate plastic pipe that is inserted in a casing or an abandoned pipeline.

(7) Nondestructive testing reports.
(8) Bending calculations.
(9) Fabrication and as-built drawings.
(10) Cathodic protection documentation.
(11) Test charts or electronic testing logs.

(b) Records may be kept in a variety of formats that include the following.
(1) Paper.
(2) Work management systems.
(3) Geographic information system (GIS).
(4) Other electronic databases.

§192.329

Installation of plastic pipelines by trenchless excavation.

[Effective Date: 01/22/19]

Plastic pipelines installed by trenchless excavation must comply with the following:

(a) Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation.

(b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by § 192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.

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

GUIDE MATERIAL

GENERAL REQUIREMENTS

(a) See Substructure Damage Prevention Guidelines for Directional Drilling and Other Trenchless Technologies under Guide Material Appendix G-192-6.
(b) See weak link guide material under Guide Material Appendix G-192-15B, Section 5.

SUBPART H
CUSTOMER METERS, SERVICE REGULATORS, AND SERVICE LINES

§192.351
Scope.

[Effective Date: 11/12/70]

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

GUIDE MATERIAL

No guide material necessary.

§192.353
Customer meters and regulators: Location.

[Effective Date: 10/15/03]

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

(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.

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

(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.

[Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

1 GENERAL RECOMMENDATIONS

(a) Where practical, no building should have more than one service line.
(b) Meters should normally be installed at the service regulator. When more than one meter is set on a particular premises, they should typically be set at one location. If meters are installed at multiple locations on the premises, the operator should consider providing a tag or other means to indicate that there are multiple meter locations.
(c) Outside, aboveground meter and regulator locations are desirable when weather conditions, availability of space, and other conditions permit.

(a) If the customer's utilization equipment (e.g., gas compressor) could produce an excessive drop in gas pressure or a vacuum at the meter or regulator, a protective device such as the following should be used.
   (1) Automatic shut-off valve with manual reset (for decreasing pressure).
   (2) Restricting orifice.
   (3) Regulating device set to close at a predetermined decrease in pressure.
(b) If the customer's utilization equipment could cause compressed gas, compressed air, oxygen, etc., to flow back into the meter or regulator, a protective device such as the following should be used.
   (1) Check valve.
   (2) Automatic shut-off valve with manual reset (for increasing pressure).
   (3) Regulating device set to close at a predetermined increase in pressure. The protective device should provide gastight shutoff if flow reversal occurs. Consideration should be given to the explosion hazard of air or oxygen mixed with natural gas or other hydrocarbons.
(c) If a supplementary or an alternate gas supply (e.g., LPG) is interconnected for standby use and could flow back into the meter or regulator, a protective device such as those listed in 1 (a) and (b) above should be used. A 3-way valve that closes the normal gas supply before admitting the alternate supply could eliminate the need for a protective device.

2 CORROSION DAMAGE

If corrosion damage is likely to occur to meters and service regulators, see guide material under §192.479.

3 CONSIDERATIONS TO MINIMIZE DAMAGE BY VEHICLES AND OTHER OUTSIDE FORCES

See 2(b) of the guide material under §192.353 and Guide Material Appendix G-192-13.

4 REGULATOR AND RELIEF VENTS AND VENT PIPING

4.1 Outside vents and vent piping termination.
All outside regulator vents and the outside terminations of all service regulator vent and relief lines should have vented caps, fittings, or other protection. The protection should be installed in accordance with the manufacturer's instructions, and should meet the requirements of §192.355(b). Where there is a potential for exposure to severe water or freezing conditions, special fittings or other arrangements should be used which will prevent blocking of the vent or relief line or interference with the operation of the regulator due to ice and water.

4.2 Inside regulators.
See §§192.353 and 192.357 for design and location considerations for inside regulators. See 4.3 below for vent piping design considerations.

4.3 Vent piping design.
(a) Single regulator or relief vent.
   Vent piping should be designed to be continuous to the outside of the building and minimize the back pressure if the regulator diaphragm ruptures or the relief valve activates.
(b) Multiple regulator or relief vents.
   Typically, a separate vent line is used for each regulator or relief valve as in (a), but a properly designed common vent line may be used.
   (1) A common vent line should be designed and sized to:
      (i) Minimize back pressure to the connected regulator having the largest venting flow rate, if venting occurs.

(ii) Ensure that the outlet pressure of the other connected regulators does not increase to an unsafe value. If a regulator diaphragm ruptures or a relief valve activates and gas flows through the common vent line, the resultant back pressure will cause the outlet pressure of the other connected regulators to increase by the back-pressure amount. The amount of back pressure depends on the diameter and length of the common vent line and the venting flow rate.
(iii) Ensure that the total maximum vent line pressure for all regulators connected does not exceed the maximum back pressure specified for any one of the connected regulator vents.
(iv) Ensure that all the regulators connected to a common vent line have the same delivery pressure.

(2) Regulators with low-pressure delivery (utilization pressure for low-pressure gas burning equipment) should have no high-pressure delivery regulator connected to the common vent line installation.
(3) When considering the addition of regulators to an existing common vent line:
(i) Do not connect a regulator with a different delivery pressure.
(ii) Do not connect a regulator with a larger venting flow rate than used in the initial design, unless a new calculation indicates that the common vent line is adequate at the larger venting flow rate.
(4) The operator should consider using regulators with either:
(i) A device set to close at a predetermined increase in pressure, or
(ii) Using an automatic shut-off valve with a manual reset.

5 PITS AND VAULTS

(a) See guide material under §192.353 for design and location considerations.
(b) When service regulators are installed in underground pits or vaults, regulator and relief vents should be installed in a manner to prevent blocking of the vents where there is a potential for soil or water accumulation.

§192.357

Customer meters and regulators: Installation.

[Effective Date: 11/12/70]

(a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.

(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.

(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.

GUIDE MATERIAL

1 ACCESSIBILITY

The meter should be installed where it can be easily read and the connections are accessible. See guide material under §192.353 for location considerations.

2 MINIMIZING ANTICIPATED STRESSES

(a) Care should be taken to ensure that the meter set assembly is not installed under stress.
(b) Where practical, the outside portion of the service line, including associated piping, should be designed so that damage to the service line due to outside forces will not cause leakage inside a building.
(c) Swing joint piping techniques may be used to reduce the problems of piping stress and for ease of installation. For pipe sizes up to NPS 1¼, where meter bars are not installed for piping support, it is common industry practice to use swing joint piping.
(d) For threaded metallic joints, see guide material under §192.273.
(e) Piping should be supported to minimize stress on the regulator body, meter case, and piping. Appropriate blocking, pads, stands, brackets, and hangers should be used as necessary. Supports for horizontal steel piping should be spaced so that the distances listed in Table 192.357i are not exceeded.
(f) Reasonable precautions, such as increased pipe wall thickness, may be taken to protect the meter set assembly or service regulator from natural or other hazards.

MAXIMUM HORIZONTAL SUPPORT SPACING FOR STEEL PIPING	
Nominal Pipe Size (Inches)	**Maximum Support Spacing (Feet)**
½	6
¾ or 1	8
1¼ through 2	10
2 and larger	See MSS SP-58

TABLE 192.357i

3 VENTING OF REGULATORS AND RELIEFS TO THE OUTSIDE ATMOSPHERE

Vent piping should be installed to ensure a continuous, unobstructed path to the outside atmosphere. See 4 and 5 of the guide material under §192.355.

§192.359

Customer meter installations: Operating pressure.

[Effective Date: 07/13/98]

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

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

No guide material necessary.

§192.361

Service lines: Installation.

[Effective Date: 10/15/03]

(a) *Depth*. Each buried service line must be installed with at least 12 inches (305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.

(b) *Support and backfill*. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.

(c) *Grading for drainage*. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.

(d) *Protection against piping strain and external loading*. Each service line must be installed so as to minimize anticipated piping strain and external loading.

(e) *Installation of service lines into buildings*. Each underground service line installed below grade through the outer foundation wall of a building must —

(1) In the case of a metal service line, be protected against corrosion;

(2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and

(3) Be sealed at the foundation wall to prevent leakage into the building.

(f) *Installation of service lines under buildings*. Where an underground service line is installed under a building —

(1) It must be encased in a gas tight conduit;

(2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and

(3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.

(g) *Locating underground service lines.* Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with §192.321(e).

[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003

GUIDE MATERIAL

1 COVER CONSIDERATIONS

(a) Where cover requirements cannot be met due to existing substructures, the portions of the service lines which could be subjected to superimposed loads should be cased or bridged, or the pipe should be appropriately strengthened.

(b) See Guide Material Appendix G-192-13 for additional cover considerations and for considerations to minimize damage by outside forces.

(b) An evaluation of the pipe condition.
(c) The extent of the initial investigation.
(d) The extent of any additional investigation conducted, if remedial action is required.

3 ADJACENT UNDERGROUND STRUCTURES

3.1 General.
When inspecting the exposed pipeline, consideration should be given to the proximity and condition of existing conduits, ducts, sewer lines and similar structures, including abandoned facilities, which might have the potential to provide a path for the migration of leaking gas.

3.2 Cathodic shielding.
Visual inspection for corrosion is an effective method to determine cathodic shielding of a pipeline. The area exposed around a pipeline should be inspected for foreign objects that can contribute to cathodic shielding. Once a corroded or shielded area is discovered, remedial measures should be taken. See 9.2 of the guide material under §192.465 for further information regarding shielding of current.

4 INSPECTING PIPELINE IN CASINGS

4.1 Visual inspection.
Normally, it is impractical to inspect a carrier pipe in a casing. Whenever the encased carrier pipe is exposed, it should be visually inspected. Visual inspection of the encased carrier pipe for atmospheric corrosion conditions within casings should be made in those situations where the casing must be lengthened due to road widening or other construction, and where the carrier pipe must be pulled out of the casing and replaced.

4.2 In-line inspection (ILI).
ILI surveys may be used to evaluate corrosion of an encased carrier pipe. However, it is normally not practical to use this technique except when it is part of a general ILI survey.

5 INTEGRITY MANAGEMENT CONSIDERATIONS

The examination of exposed buried pipelines might provide additional opportunities for acquiring data to include in the threat and risk analysis required by an integrity management program, such as §§192.917 and 192.1007. An operator should review the data collection and integration processes associated with its integrity management plan to determine if additional data collection is beneficial. Procedures and forms may need to be modified to include additional data collection. Data collected should be made available to integrity management personnel.

§192.461

External corrosion control: Protective coating.

[Effective Date: 05/24/23]

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

(1) Be applied on a properly prepared surface;

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

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling (including, but not limited to, transportation, installation, boring, and backfilling) and soil stress;

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

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

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

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

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

(f) Promptly after the backfill of an onshore steel transmission pipeline ditch following repair or replacement (if the repair or replacement results in 1,000 feet or more of backfill length along the pipeline), but no later than 6 months after the backfill, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys must be conducted, except in locations where effective coating surveys are precluded by geographical, technical, or safety reasons.

(g) An operator must notify PHMSA in accordance with § 192.18 at least 90 days in advance of using other technology to assess integrity of the coating under paragraph (f) of this section.

(h) An operator of an onshore steel transmission pipeline must develop a remedial action plan and apply for any necessary permits within 6 months of completing the assessment that identified the deficiency. The operator must repair any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with section 4 of NACE SP0502 (incorporated by reference, *see* § 192.7) within 6 months of the assessment, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after the receipt of permits.

(i) An operator of an onshore steel transmission pipeline must make and retain for the life of the pipeline records documenting the coating assessment findings and remedial actions performed under paragraphs (f) through (h) of this section.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

1 REFERENCES

References are contained in Table 192.461i.

REFERENCES	
Federal Regulation	**NACE Document [1]**
§192.461(a)	SP0169, Section 5
§192.461(b)	SP0169, Section 5
§192.461(c)	SP0274
§192.461(d)	SP0169, Section 5 RP0375, Section 5
[1] For document titles, see Guide Material Appendix G-192-1, Section 1.9.	

TABLE 192.461i

2 BORING OR DRIVING (§192.461(e))

See 2 of the guide material under §192.361.

§192.463

External corrosion control: Cathodic protection.

[Effective Date: 08/01/71]

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

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

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

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

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

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971]

GUIDE MATERIAL

Amphoteric metal, as defined in NACE SP0169, is a metal that is susceptible to corrosion in both acid and alkaline environments (e.g., aluminum and copper).

§192.465

External corrosion control: Monitoring and remediation.

[Effective Date: 05/24/23]

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

(b) Cathodic protection rectifiers and impressed current power sources must be periodically inspected as follows:

(1) Each cathodic protection rectifier or impressed current poser source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.

(2) After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection, must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within one year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part.

(1) Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.

(2) To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-35, 44 FR 75384, Dec. 20, 1979 with Amdt. 192-35A, 45

FR 23441, Apr. 7, 1980; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192.93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

1 METHODS FOR MONITORING CATHODICALLY PROTECTED PIPELINES

(a) Monitoring requirements of pipeline cathodic protection (CP) systems may be satisfied by on-site, remote, or other testing and inspection methods.
(b) A rectifier or other cathodic protection device protecting a regulated segment of gathering line could be located outside the limits of the regulated pipe segment.

2 REMEDIAL ACTION TO CORRECT DEFICIENCIES FOUND BY MONITORING

(a) Common corrosion control methods include coating, CP, and electrical isolation. CP systems typically use galvanic anodes or impressed current (rectifiers). Other corrosion control devices may include electrical isolators, interference bonds, diodes, and reverse current switches.
(b) Remedial action is required whenever it is determined that the CP or other installed corrosion control methods are not operating effectively.
(c) The specific remedial action to be taken depends on the type of corrosion control method installed and the problem encountered. In certain situations, the deficiency can be corrected by modifying existing corrosion control methods (e.g., increasing output from adjacent rectifiers).
(d) Operators are required to take prompt remedial action to correct deficiencies indicated by monitoring. Remedial action should correct the deficiency before the next monitoring cycle required by §192.465. However, for monitoring cycles greater than one year, remedial action should be completed within 15 months of discovery.
Example: It is discovered that pipe coating has deteriorated and that the existing corrosion control system is unable to achieve the desired CP level. The operator should initiate and document action taken to achieve the acceptable CP level before the next monitoring cycle. Remedial action might include the following.
(1) Installing additional CP,
(2) Recoating the pipe to meet the requirements of §192.461, or
(3) Replacing the pipe.
(e) If remedial action cannot be completed prior to the next scheduled monitoring cycle, the operator should document the actions taken to correct the deficiency and the expected timeframe for completion.

3 METHODS FOR LOCATING CORROSION AREAS ON UNPROTECTED PIPELINES

(a) Unprotected pipeline as used in §192.465(e) means a metallic pipeline (other than cast iron and ductile iron) that is not cathodically protected in accordance with §192.463. The most effective, practical, and reliable methods to evaluate or determine areas of corrosion on gas facilities will vary with the type and location of facilities. Historically, electrical-type surveys have been practical and effective on transmission pipelines and other pipelines in rural areas (see 9 below). In-line inspection (ILI) may also be useful where the pipeline will accommodate this equipment (see Guide Material Appendix G-192-14). Pipelines in urban areas present great difficulty in the use of ILI tools and in the practical application and interpretation of electrical-type surveys. The use of such surveys will generally be precluded in urban areas by the considerations in 9.2 below.
(b) Where electrical-type surveys are considered impractical or ineffectual, leak surveys and a review of leak survey results, corrosion leak repair history, and records of exposed pipe examinations are the most effective means of determining corrosion areas. In addition, §192.465(e) requires an operator to consider the pipeline environment that could affect the probability of active corrosion. Leak surveys and records review may be the most appropriate method to determine corrosion areas on distribution

gas facilities and other gas facilities in urban areas. On-stream corrosion detectors, pressure tests, ultrasonic, acoustical, visual, or other methods may be applicable in special cases.

4 DETERMINING ACTIVE CORROSION ON UNPROTECTED PIPELINES

4.1 Considerations.

The determination that active corrosion exists depends on an assessment of whether conditions in known or suspected corrosion areas are such that continuing corrosion could result in a detriment to public safety. For determining if a known or suspected corrosion area involves continuing corrosion, use personnel who are qualified in corrosion control methods (see §192.453 and Subpart N for qualification requirements, as applicable). For determining if a detriment to public safety could result, the operator should use personnel who are, at a minimum, qualified by training or experience. The following factors should be considered in assessing the effect on public safety.

(a) Leak frequency.
(b) Pressure.
(c) Location of piping.
(d) Location of dwellings and other structures.
(e) Gas venting and migration characteristics of the area.

4.2 Determination.

Continuing corrosion should be considered as active corrosion if it is determined that operation and maintenance actions will not control the corrosion condition to an extent that prevents it from becoming detrimental to public safety.

5 "NOT ACTIVE" CONTINUING CORROSION ON UNPROTECTED PIPELINES

(a) If continuing corrosion is determined to be "not active," CP or other corrective measures may not be required. One method of assessing continuing corrosion is by a measured or calculated corrosion rate of the pipe in the area of concern. Application of the corrosion rate to the pipe could result in an estimate of when the pipe might become a detriment to public safety. Corrective measures would be required prior to that time. Such an analysis would be required at least every three years at intervals not exceeding 39 months, since §192.465(e) requires an unprotected pipeline be reevaluated every three years at intervals not exceeding 39 months for the existence of active corrosion.
(b) Corrosion that is currently considered "not active" could also become active due to growth of public presence in the vicinity of the pipeline. An increase in the rate of corrosion is not necessarily required.

6 CORRECTING ACTIVE CORROSION ON UNPROTECTED PIPELINES

6.1 Corrective measures.

Where it has been determined that active corrosion exists, §192.465(e) requires CP in accordance with Subpart I for the pipeline in areas of active corrosion. The following corrective measures should be considered.

(a) Cathodically protecting the pipeline in areas of active corrosion. The following measures should be considered to assist in the application of CP.
    (1) Coating or recoating the pipe.
    (2) Controlling stray current.
    (3) Mitigating CP current shielding effects or non-galvanic corrosion, such as microbiologically influenced corrosion (MIC).
(b) Replacing with plastic pipe or coated steel pipe.
(c) Abandonment.

6.2 Prompt action.

Operators should take prompt action when an area of active corrosion is found. Corrective action should be completed within 15 months of discovery, or earlier if analysis indicates a shorter interval is

(2) The buried grounding facility.
(3) The ground wire.

(e) Protection of insulating joints in the pipeline against induced voltages or currents resulting from lightning strikes. This can be obtained by the following.
(1) Connecting buried sacrificial anodes to the pipe near the insulating joints.
(2) Bridging the pipeline insulator with a spark-gap.
(3) Other effective means.

(f) Cable connections from insulating devices to lightning and fault current arrestors should be short, direct, and of a size suitable for short-term, high current loading.

(g) The electrical properties of nonwelded joints. (Where the objective is to ensure electrical continuity, it may be achieved by using fittings manufactured for this purpose or by bonding the mechanical joints in an approved manner. Conversely, if an insulating joint is required, a device manufactured to perform this function should be used. In either case, these fittings should be installed in accordance with the manufacturer's instructions.)

5 REFERENCES

(a) NACE SP0177, "Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems."
(b) NACE SP0200, "Steel-Cased Pipeline Practices."

§192.469

External corrosion control: Test stations.

[Effective Date: 11/01/76]

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

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976]

GUIDE MATERIAL

1 CONTACT POINTS

Any contact point location (e.g., valves, blowoffs, meters, service lines, regulators, regulator vents and platform risers, which are electrically continuous with the structure under test) may be chosen for testing as long as the level of cathodic protection is effectively determined.

2 TEST LEADS

Some typical test lead locations include the following.
(a) Pipe casing installations.
(b) Foreign metallic structure crossings.
(c) Insulating joints.
(d) Waterway crossings.
(e) Bridge crossings.
(f) Road crossings.
(g) Galvanic anode installations.
(h) Impressed current anode installations.

§192.471

External corrosion control: Test leads.

[Effective Date: 08/01/71]

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

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

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

[Issued by Amdt 192-4, 36 FR 12297, June 30, 1971]

GUIDE MATERIAL

1 INSTALLATION METHODS

Some acceptable methods include the following.

1.1 Thermit welding.

(a) Steel. Attachment of electrical leads directly to steel pipe by the thermit welding process using copper oxide and aluminum powder. The thermit welding charge should be limited to a 15-gram cartridge.

(b) Cast iron. Attachment of electrical leads directly to cast or ductile-iron pipe by the thermit welding process using copper oxide and aluminum powder. The thermit welding charge should be limited to a 32-gram cartridge.

1.2 Solder connections.

Attachment of electrical leads directly to steel pipe with the use of soft solders or other materials that do not involve temperatures exceeding those for soft solders.

1.3 Brazing.

Attachment of electrical leads to steel pipe by brazing, provided that the pipeline operates at less than 29% SMYS.

1.4 Mechanical connections.

Mechanical connections which remain secure and electrically conductive.

2 OTHER CONSIDERATIONS

For convenience, conductors may be coded or permanently identified. Wire should be installed with slack. Damage to insulation should be avoided. Repairs should be made if damage occurs. Test leads should not be exposed to excessive heat or excessive sunlight.

§192.473

External corrosion control: Interference currents.

[Effective Date: 05/24/23]

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

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

(c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;

(3) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and

(4) Application for any necessary permits within 6 months of completing the interference survey that identified the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

1 REFERENCE

A reference is NACE SP0169, Section 9.

2 INSTALLATION CONSIDERATIONS

(a) Attention should be given to a new pipeline's physical location, particularly if the location may subject the pipeline to stray electrical currents from other facilities, such as the following.
   (1) Other pipelines or utilities with associated cathodic protection (CP) systems.
   (2) Rail transit systems.
   (3) Mining or welding operations.
   (4) Induced currents from electrical transmission lines.

(b) To the extent possible, the operator should identify and plan for the mitigation and control of anticipated stray electrical currents prior to construction. As soon as practicable after construction of the pipeline or facility to be protected is completed, the operator should implement monitoring, testing, and mitigation plans to control the effects of stray electrical currents. The rate of corrosion caused by stray electrical current can be higher than the rate of corrosion resulting from galvanic action.

3 EXTERNAL CORROSION CONTROL EFFECTIVENESS

Once the interference control methods have been established, periodic tests and inspections should be conducted to ensure their continued effectiveness.

§192.475

Internal corrosion control: General.

[Effective Date: 07/13/98]

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

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

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

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

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

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 cubic feet (5.8 milligrams/m^3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL

In the presence of free water, gases containing certain constituents, such as carbon dioxide, hydrogen sulfide, and oxygen, can be corrosive to steel pipelines. Pipeline liquids may combine with these constituents and cause corrosion that may be detrimental to pipeline integrity. Because of this, monitoring and evaluating corrosion, operating conditions, gas quality, and liquids found in pipelines are important elements of internal corrosion control programs. The following are considerations for managing internal corrosion.

2 DESIGN CONSIDERATIONS

If it is anticipated, or has been determined, that the gas to be transported is corrosive, the following should be considered for the design of the pipeline system.

(a) Selection of special materials.
  (1) Nonmetallic materials.
  (2) Nonferrous metals.
  (3) Special alloy steels.
(b) Selection of steel pipe.
  (1) Increased wall thickness.
  (2) Pipe grade.
  (3) Metallurgy.
  (4) Internal coating.
(c) Effect of high, low, or no flow velocities and liquid accumulation.
(d) Piping configurations that can contribute to changes in flow velocities, which can cause the free water and constituents to settle out of the gas stream and build into concentrations that could lead to internal corrosion. Examples of these configurations include the following.

(1) Dead ends.
(2) Sags or low spots.
(3) Fittings and mechanical connections.
(4) Sharp bends (vertical or horizontal).
(5) Sudden diameter changes.
(6) Drips.
(7) Crossover piping between systems with normally closed valves.

(e) Corrosion monitoring devices and access fittings for them.
(f) Physical location of the pipe, since external climate, heat sources, and environment can affect internal temperature.
(g) Selection and location of liquid separation, dehydration, or gas scrubbing equipment.

3 DETECTION METHODS

The following may be used to detect internal corrosion.

(a) Visual inspection of piping and components.
  (1) Access ports.
  (2) Selective cut-outs.
(b) Corrosion monitoring devices.
  (1) Corrosion coupons and spools.
  (2) Resistance probes

(3) Polarization probes.
(4) Hydrogen probes and patches.
(5) Electrochemical probes.

(c) Sampling.
(1) Liquids analysis.
(i) Chemical composition.
(ii) Microbiological composition.
(2) Gas composition analysis.
(3) Solids analysis.
(i) Chemical composition.
(ii) Microbiological composition.

(d) Trending of analytical data.
(e) Internal inspection tools.
(f) Ultrasonic inspection.
(g) Radiography.
(h) Failure analysis.
(i) Internal corrosion direct assessment.

4 FREQUENCY

The following considerations could impact the frequency of monitoring or testing.

(a) Location and history of water removal.
(b) Age and condition of pipe and drips.
(c) Internal corrosion history, including leaks and ruptures.
(d) Liquids composition.
(e) Gas composition.
(f) System operating parameters (e.g., temperature, pressure, volumes transported, wet system vs. dry).
(g) System physical layout (e.g., topography).
(h) Flow characteristics.
(i) Proximity to dwellings and the public.
(j) Class location, HCAs, or identified sites (see §192.903).
(k) Pipeline segments downstream of production or storage fields where free water and constituents might accumulate.
(l) Solids composition.
(m) Past inspection results.
(n) Past results obtained using corrosion monitoring devices.
(o) System design (e.g., materials of construction, pipe wall thickness, pigging facilities, presence of drips).

5 MITIGATIVE MEASURES

The following measures can be used to mitigate internal corrosion.

(a) Control of moisture level (e.g., by dehydration, separation, or temperature control).
(b) Reduction of corrosive constituents (chemical or biological) in the gas.
(c) Internal coating.
(d) Liquids or solids removal.
(1) Pigging **-** frequency of pigging will depend on both the volume and the analysis of materials received during pigging operations.
(2) Drips **-** frequency of operation will depend on both the volume and analysis of materials removed.
(3) Separators **-** frequency of maintenance will depend on changes in results from liquids analyses.

(e) Chemical or biological treatments.
(1) Treatments should not cause deterioration of piping system components.
(2) Treatments should be compatible with the following.

5.4 Monitoring devices.

Where the operator has determined that monitoring is necessary at locations with significant potential for internal corrosion, the operator will need to document this determination and that the devices were installed (see §192.476(d)). The operator should also document the following.

(a) Location of equipment.
(b) Sampling protocols.
(c) Procedures for managing upsets.
(d) Calibration process and intervals.

5.5 Documenting impracticable or unnecessary.

The operator is required to document when a design feature is impracticable or unnecessary (see §192.476(d)). The documentation would discuss reasons why it was impracticable or unnecessary to meet the specified design or construction requirements. This documentation may be filed in the operator's design or as-built record system.

5.6 Changes to configuration.

When changing the configuration of a transmission line, the operator is required to document the impact of the change on internal corrosion risk to the downstream portion of an existing onshore transmission line (see §192.476(d)). This documentation may be filed in the operator's design or as-built record system. See 5.3 and 5.4 above.

5.7 Retention.

Records should be kept as long as the pipeline remains in service.

6 REFERENCES

(a) NACE SP0102 (formerly RP0102), "In-Line Inspection of Pipelines."
(b) NACE SP0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems."
(c) NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)."
(d) NACE 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications."
(e) Guide Material Appendix G-192-14.

§192.477

Internal corrosion control: Monitoring.

[Effective Date: 09/05/78]

If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978]

GUIDE MATERIAL

(a) Devices that can be used to monitor internal corrosion or the effectiveness of corrosion mitigation measures include hydrogen probes, corrosion probes, corrosion coupons, test spools, and nondestructive testing equipment capable of indicating loss in wall thickness.

(b) Consideration should be given to the site selection and the type of access station used to expose the device to on-stream monitoring. It is desirable to incorporate a retractable feature in the monitoring station to avoid facility shutdowns during periodic inspections, such as weight loss measurements, and for on-stream pigging of the facility.

(c) A written procedure should be established to determine that the monitoring device is operating properly.

(d) See guide material under §192.475 if internal corrosion is discovered or is not under mitigation.

§192.478

Internal corrosion control: Onshore transmission monitoring and mitigation.

[Effective Date: 05/24/23]

(a) Each operator of an onshore gas transmission pipeline with corrosive constituents in the gas being transported must develop and implement a monitoring and mitigation program to mitigate the corrosive effects, as necessary. Potentially corrosive constituents include, but are not limited to: carbon dioxide, hydrogen sulfide, sulfur, microbes, and liquid water, either by itself or in combination. An operator must evaluate the partial pressure of each corrosive constituent, where applicable, by itself or in combination, to evaluate the effect of the corrosive constituents on the internal corrosion of the pipe and implement mitigation measures as necessary.

(b) The monitoring and mitigation program described in paragraph (a) of this section must include:

(1) The use of gas-quality monitoring methods at points where gas with potentially corrosive contaminants enters the pipeline to determine the gas stream constituents.

(2) Technology to mitigate the potentially corrosive gas stream constituents. Such technologies may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects;

(3) An evaluation at least once each calendar year, at intervals not to exceed 15 months, to ensure that potentially corrosive gas stream constituents are effectively monitored and mitigated.

(c) An operator must review its monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, and based on the results of its monitoring and mitigation program, implement adjustments, as necessary.

[Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

§192.479

Atmospheric corrosion control: General.

[Effective Date: 10/15/03]

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

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

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

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

1 GENERAL

(a) The need for coating can be determined by experience in the same or essentially identical environment.
(b) The degree of surface preparation, the selection of the coating materials, and the application procedures must be selected to achieve the desired coating system life span. A reference is the SSPC Painting Manual ("Good Painting Practice" - Volume 1; and "Systems and Specifications" - Volume 2), which is published by the Steel Structures Painting Council.
(c) For determining areas of atmospheric corrosion, see guide material under §192.481.

2 EXPOSED PIPING AND RELATED FACILITIES

The following methods should be considered for exposed piping and related facilities.
(a) Use of coating. See 1 above.
(b) Selection of corrosion resistant materials.
(c) Avoidance of areas where prevailing winds or other conditions will deposit corrosive materials (e.g., salt, moisture, industrial effluent). Protection in these areas can be provided by selecting a more appropriate meter and regulator location or by using a protective housing.
(d) Use of materials or coatings or both suitable for the environment may be required for facilities installed in pits, vaults, or casings and that may be periodically submerged or exposed to excessive condensation.
(e) Protection of regulator vent lines from plugging by corrosion products. Where practical, the vent line should be installed in a self-drain position and, where necessary, extended above possible flood

level.

(f) Use of material for vent tubing that is compatible with the environment encountered. For example, some kinds of plastic tubing should not be exposed to direct sunlight, and certain aluminum alloys should not be submerged or placed in contact with concrete.

§192.481
Atmospheric corrosion control: Monitoring.
[Effective Date: 03/12/21]

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

Pipeline type:	**Then the frequency of inspection is:**
(1) Onshore other than a Service Line..............	**At least once every 3 calendar years, but with intervals not exceeding 39 months.**
(2) Onshore Service Line....................................	**At least once every 5 calendar year, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.**
(3) Offshore	**At least once each calendar year, but with intervals not exceeding 15 months.**

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

(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by §192.479.

(d) If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

DETERMINING AREAS OF ATMOSPHERIC CORROSION

(a) Type A and B gathering line overpressure devices or valves that lie outside of the regulated segments (see §192.8(b)) are not required to have inspections for atmospheric corrosion.

(b) The presence of atmospheric corrosion can be detected best by visual inspection.

(1) This may require ladders, scaffolds, hoists, or other suitable means of permitting inspector access to the structure being inspected. In addition to the locations listed in §192.481(b), attention should be given to locations such as clamps, rest plates, and sleeved openings.

(2) Piping that is thermally or acoustically insulated (jacketed) should be inspected wherever practical. To minimize damage to the insulation, a visual inspection of the pipe may be performed by cutting

windows into the insulation.

(c) Exposure test racks can be used to evaluate coatings and materials in local environments such as industrial, coastal, and offshore locations. Many standard procedures or test methods for evaluating materials and coatings are available from the ASTM International.

(d) Evidence of atmospheric corrosion on meters and regulators may also be determined by inspection by operator employees such as meter readers and leak survey personnel.

§192.483

Remedial measures: General.

[Effective Date: 08/01/71]

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

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

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

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971]

GUIDE MATERIAL

No guide material necessary.

§192.485

Remedial measures: Transmission lines.

[Effective Date: 05/24/23]

(a) *General corrosion*. Each segment of transmission line pipe with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced or the operating pressure reduced commensurate with the strength of the pipe based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

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

(c) *Calculating remaining strength.* Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with § 192.712

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999; Amdt. 192-119, 80 FR 168, Jan. 5, 2015, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

1 EVALUATION

1.1 Introduction.

The evaluation of the pressure strength of a corroded region in a transmission pipeline to determine its suitability for continued service can be made by an analytical method, by pressure testing, or by an alternate method.

1.2 Pressure testing.

The pipe containing the corroded region may be pressure tested to confirm the established MAOP, or to determine a lower MAOP. The pressure test should be in accordance with the general requirements of Subpart J (in particular §192.503), and the pressure should be held for at least 8 hours. The established MAOP may be confirmed by testing to a pressure at least equal to the MAOP times the appropriate factor in Table 192.485i or ii below. A lower MAOP may be established by dividing the successful test pressure by the appropriate factor.

(a) For pipeline segments that have not been confirmed for operation in the next higher class location, see §192.611:

CLASS LOCATION	FACTOR
Class 1 locations	
• No buildings for human occupancy within 300 feet	1.10
• With buildings for human occupancy within 300 feet	1.25
Class 2 locations	1.25
Class 3 & 4 locations and Meter & Compressor Station piping in Class 1 & 2 locations	1.5

TABLE 192.485i

(b) For pipeline segments that are required to be qualified for an existing class location, see §192.611:

CLASS LOCATION	FACTOR
Class 2	1.25
Class 3	1.50
Class 4	1.80

TABLE 192.485i

item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the pressure required for the pipeline to which it is being added; or

(3) The component carries a pressure rating established through applicable ASME/ANSI, Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (MSS) specifications, or by unit strength calculations as described in §192.143.

[Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-60, 53 FR 36028, Sept. 16, 1988 with Amdt. 192-60A, 54 FR 5484, Feb. 3, 1989; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

(a) The test procedure should give consideration to such items as the following.
- (1) The method and equipment used.
- (2) The test medium and maximum test pressure.
- (3) The duration of the test.
- (4) The volumetric content of the piping and its location.
- (5) The reason for the pressure test.
  - (i) New construction.
  - (ii) Pipe replacement.
  - (iii) Class location changes.
  - (iv) Uprating.
  - (v) Integrity assessment.
  - (vi) Other as deemed appropriate by the operator.

(b) In accordance with §192.503(e)(3), a single component with a valid ASME or MSS specification pressure rating may be installed without a strength test. Rating examples are common designations, such as ASME Class 600. Corresponding temperature limits need to be considered for each pressure rating.

(c) See §192.619 for test pressure requirements to substantiate the maximum allowable operating pressure for steel and plastic pipelines.

(d) See guide material under §192.517 and Guide Material Appendices G-192-9, G-192-9A, and G-192-10.

§192.505

Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.

[Effective Date: 03/12/21]

(a) Except for service lines, each segment of a steel pipeline that is to operate at a hoop stress of 30 percent or more of SMYS must be strength tested in accordance with this section to substantiate the proposed maximum allowable operating pressure. In addition, in a Class 1 or Class 2 location, if there is a building intended for human occupancy within 300 feet (91 meters) of a pipeline, a hydrostatic test must be conducted to a test pressure of at least 125 percent of maximum operating pressure on that segment of the pipeline within 300 feet (91 meters) of such a building, but in no event may the test section be less than 600 feet (183 meters) unless the length of the newly installed or relocated pipe is less than 600 feet (183 meters). However, if the buildings are evacuated while the hoop stress exceeds 50 percent of SMYS, air or inert gas may be used as the test medium.

(b) In a Class 1 or Class 2 location, each compressor station, regulator station, and measuring station must be tested to at least Class 3 location test requirements.

(c) Except as provided in paragraph (d) of this section, the strength test must be conducted by maintaining the pressure at or above the test pressure for at least 8 hours.

(d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation strength test must be conducted by maintaining the pressure at or above the test pressure for at least 4 hours.

[Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

1 GENERAL

The following preliminary considerations should be noted.

(a) Because of the requirements of §192.611 and the possibility of a change in class location, especially in Class 1 and Class 2 locations, a strength test to at least 90% SMYS is recommended.

(b) A pipeline crossing a railroad, public road, street, or highway might be tested in the same manner and to the same pressure as the pipe on each side of the crossing, recognizing that the pipeline in the crossing might have a different design factor. See §192.111 and the design formula under §192.105.

(c) Fabricated assemblies (e.g., mainline valve assemblies, crossover connections, and river crossing headers) installed in pipelines in Class 1 locations may be tested as required for Class 1 locations (even though §192.111 requires a Class 2 design factor).

(d) Testing against closed valves is not recommended. Testing should include the use of test manifolds. Blinds (e.g., flanges or plates) should be used as necessary to minimize testing against any closed valves. Where valves exist in a test section, they should remain in the open or manufacturer's recommended position during the test. To ensure that air does not enter the gas system, testing with air against a closed valve that is connected to the gas system is not advisable.

(e) For lateral connections to transmission lines and transmission line replacements, see Note (1) in Guide Material Appendix G-192-9.

2 TEST PROCEDURE

The test procedure used should be selected after giving due consideration to items such as the following.

(a) Equipment to be used.
(b) Test medium.*
(c) Environment.
(d) Elevation profile.
(e) Volumetric content of the line.
(f) Test pressure.*
(g) Duration of the test.*
(h) Location of the line.
(i) The effects of temperature changes on the pressure of the test medium.
(j) The reason for the strength test.
    (1) New construction.
    (2) Pipe replacement.
    (3) Class location changes.
    (4) Uprating.
    (5) Integrity assessment.*
    (6) Other as deemed appropriate by the operator.

*See Guide Material Appendices G-192-9 and G-192-9A.

4.2 Procedures and guide material used to recognize a potential safety-related condition.

Personnel who perform O & M activities may use O & M procedures written in compliance with Subparts I, L and M and the associated guide material and guide material appendices to recognize anomalies or events that could become safety-related conditions. Some useful sections in Subparts I, L, and M include:

192.455	192.473	192.485	192.614	192.711	192.721
192.459	192.475	192.487	192.615	192.713	192.723
192.465	192.477	192.489	192.705	192.715	192.739
192.467	192.481	192.613	192.706	192.717	

4.3 Analysis and follow-up of in-line inspection (ILI).

Special consideration should be given to the development of written procedures for the timely analysis of, and follow through on, information obtained through the use of an ILI tool.

(a) An anomaly discovered with an ILI tool may be determined to be a safety-related condition when adequate information is available. For instance, adequate information would be available for each anomaly that is physically examined. Absent physical examination of each indicated anomaly, adequate information may be obtained when the ILI data is validated. For guidance on validation, see Guide Material Appendix G-192-14.

(b) The date an anomaly is discovered by an operator's representative and the date the anomaly is determined by an operator's representative to be a safety-related condition are used to determine the filing deadline stated in the reporting requirements of §191.25.

(c) See §192.933 and Guide Material Appendix G-192-14.

4.4 Actions in response to potential safety-related conditions.

(a) Procedures should be established for personnel to determine if a potential safety-related condition meets the reporting criteria in §191.23 and to file a report in accordance with §191.25. See Guide Material Appendix G-191-3 for a chart useful in determining if reports must be filed.

(b) When general corrosion is discovered that has reduced the pipe wall thickness to less than that required for the MAOP, actions should be taken to restore the pipe integrity (e.g., replace the pipe, reduce the MAOP).

(c) When localized corrosion pitting is discovered that has progressed to a degree where leakage might result, actions should be taken to prevent leakage at that location, such as installing a repair clamp.

(d) When unintended movement or abnormal loading by environmental causes is discovered that impairs the serviceability of a pipeline segment, actions should be taken to monitor the pipeline segment until the integrity and serviceability can be restored.

(e) When an observed condition involving a material defect or physical damage is determined to impair the serviceability of a pipeline segment, actions should be taken to monitor the pipeline segment until the integrity and serviceability can be restored.

(f) When there are indications that the pressure of a pipeline has risen above its MAOP plus the buildup allowed for the operation of pressure limiting or control devices, consider the following actions which may vary depending upon the situation.

(1) Initial actions.

(i) Verify that an overpressure condition has occurred by performing one or more of the following.

(A) Dispatch personnel for field investigation.

(B) Review SCADA information.

(C) Review pressure records.

(ii) Isolate the malfunctioning equipment or other cause of the overpressurization, if practicable, and reduce the pressure in the pipeline to normal operating pressures.

(iii) Determine whether the magnitude of overpressure warrants taking the pipeline out of service immediately.

(iv) Determine the extent of possible impact (e.g., a single customer, multiple customers).
  (A) SCADA and pressure recorders can be used to identify overpressured segments requiring possible corrective action.
  (B) For low-pressure distribution systems, determine whether gas utilization equipment has been adversely affected. Notify affected customers if damage is suspected. Consider notifying emergency responders and public officials.

(v) Repair or replace the malfunctioning equipment that caused the overpressurization.

(2) Additional actions.
  (i) Perform an instrumented leak survey of the overpressured pipe.
    (A) Consider taking the pipeline out of service based on the nature of discovered leaks.
    (B) Consider examining and repairing non-hazardous leaks on overpressured piping.
  (ii) Determine the duration of the overpressurization.
  (iii) Address transmission lines as follows.
    (A) Comply with the notification requirements of §191.25(b).
    (B) Determine the highest percentage of SMYS attributed to the overpressure event.
    (C) For segments subject to integrity management under §192.917(e), determine whether the overpressured pipe needs to be prioritized as a high risk segment for the baseline assessment or a subsequent reassessment.
    (D) For additional information about transmission lines, see 3 above.
  (iv) Determine the cause of the overpressurization to reduce the likelihood of a recurrence. See guide material under §192.617.
  (v) Assess the need for replacement of system components exposed to pressures greater than manufacturers' test pressures.
  (vi) In the event of an operating error, see the operator's Drug and Alcohol Testing and Operator Qualification Programs, if appropriate.
  (vii) Retain documentation of the event and of the corrective actions taken to continue the safe operation of the pipeline. For recordkeeping on transmission lines, see §192.709.

(g) Leaks that may constitute an emergency are responded to in accordance with the procedures required by §§192.615 and 192.703. See leakage control guidelines for Grade 1 leaks in Guide Material Appendices G-192-11 and G-192-11A.

(h) Anomalies or events that could lead to an imminent hazard and cause a 20% or more reduction in operating pressures or shutdown of operation of the effected pipeline segment should be responded to in accordance with the procedures required by §§192.615 and 192.703.

5 SURVEILLANCE, EMERGENCY RESPONSE, AND ACCIDENT INVESTIGATION

See guide material under §§192.613, 192.615, and 192.617.

6 TRAINING

6.1 Operations and maintenance (O&M) procedures.

Each operator should establish a training program that will provide operating and maintenance personnel

§192.609

Change in class location: Required study.

[Effective Date: 11/12/70]

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

This section applies to transmission lines and Type A gathering lines operating above 40 percent SMYS.

§192.610

Change in class location: Change in valve spacing.

[Effective Date: 10/05/2022]

(a) If a class location change on a transmission pipeline occurs after October 5, 2022, and results in pipe replacement, of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24-month period, to meet the maximum allowable operating pressure (MAOP) requirements in §§192.611, 192.619, or 192.620, then the requirements in §§192.179, 192.634, 192.636, as applicable, apply to the new class location, and the operator must install valves, including rupture-mitigation valves (RMV) or alternative equivalent technologies, as necessary, to comply with those sections. Such valves must be installed within 24 months of the class location change in accordance with the timing requirement in §192.611(d) for compliance after a class location change.

(b) If a class location change occurs after October 5, 2022, and results in pipe replacement of less than 2 miles within 5 contiguous miles during a 24-month period, to meet the MAOP requirements in §§192.611, 192.619, or 192.620, then within 24 months of the class location change, in accordance with § 192.611(d), the operator must either:

(1) Comply with the valve spacing requirements of §192.179(a) for the replaced pipeline segment; or

(2) Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two RMVs or alternative equivalent technologies. The distance between RMVs and alternative equivalent technologies for the replaced segment must

not exceed 20 miles. The RMVs and alternative equivalent technologies must comply with the applicable requirements of §192.636.

(c) The provisions of paragraph (b) of this section do not apply to pipeline replacements that amount to less than 1,000 feet within any 1 contiguous mile during any 24-month period.

[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

§192.611

Change in class location: Confirmation or revision of maximum allowable operating pressure.

[Effective Date: 12/22/08]

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

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

(3) The segment involved must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

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

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

(iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

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

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

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location.

Pressure reduction under paragraph (a)(1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

[Amdt. 192-5, 36 FR 18194, Sept. 10, 1971; Amdt. 192-53, 51 FR 34987, Oct. 1, 1986; Amdt. 192-63, 54 FR 24173, June 6, 1989 with Amdt. 192-63 Correction, 54 FR 25716, June 19, 1989; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-94, 69 FR 32886, June 14, 2004; RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008]

GUIDE MATERIAL

This section applies to transmission lines and Type A gathering lines operating above 40 percent SMYS.

SPECIAL PERMIT (WAIVER) FOR CLASS LOCATION

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

(a) When the MAOP of a pipeline is not commensurate with the new class location, PHMSA-OPS will consider special permit (waiver) requests under §190.341 to implement alternative measures to provide an equivalent or greater level of safety, provided that the terms and conditions of the special permit are met. For additional guidance on PHMSA expectations for content of wavier requests and eligible pipelines, see the OPS Notice for "Development of Class Location Change Waiver Criteria" (69 FR 38948, June 29, 2004; reference Guide Material Appendix G-192-1, Section 2).

(b) Operators of interstate pipelines are required to submit special permit (waiver) requests to PHMSA-OPS. Operators of intrastate pipelines are required to submit requests to the state pipeline regulatory authority or to PHMSA-OPS if there is no state pipeline regulatory authority.

§192.612

Underwater inspection and reburial of pipelines in the Gulf of Mexico and its inlets.

[Effective Date: 09/09/04]

(a) Each operator shall prepare and follow a procedure to identify its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water that are at risk of being an exposed underwater pipeline or a hazard to navigation. The procedures must be in effect August 10, 2005.

(b) Each operator shall conduct appropriate periodic underwater inspections of its pipelines in the Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water based on the identified risk.

(c) If an operator discovers that its pipeline is an exposed underwater pipeline or poses a hazard to navigation, the operator shall—

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802, of the location and, if available, the geographic coordinates of that pipeline.

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR part 64 at the ends of the pipeline segment and at intervals of not over 500 yards (457 meters) long, except that a pipeline segment less than 200 yards (183 meters) long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year of discovery, bury the pipeline so that the top of the pipe is 36 inches (914 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) for normal excavation or 18 inches (457 millimeters) for rock excavation.

(i) An operator may employ engineered alternatives to burial that meet or exceed the level of protection provided by burial.

(ii) If an operator cannot obtain required state or Federal permits in time to comply with this section, it must notify OPS; specify whether the required permit is State or Federal; and, justify the delay.

[Issued by Amdt. 192-67, 56 FR 63764, Dec. 5, 1991; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-98, 69 FR 48400, Aug. 10, 2004]

GUIDE MATERIAL

1 IDENTIFICATION

1.1 Criteria for identifying pipelines.

Operators are required to identify their pipelines located in the Gulf of Mexico and its inlets, where the water is less than 15 feet deep as measured from mean low water. Rivers, tidal marshes, lakes, and canals are excluded. Operators may determine where the water depth of the Gulf of Mexico and its inlets is 15 feet or less by referencing USGS maps or depth charts, USCG water depth maps or tables, or their own construction and maintenance records.

1.2 Assessing risk of identified pipelines.

Operators should assess the risk of such pipelines being exposed or being a hazard to navigation by considering the following.

(a) Types of vessels navigating the water body.
(b) Traffic density of vessels navigating the water body.
(c) Possible effects that hurricanes or other significant natural occurrences might have on pipeline depth of cover.
(d) History of pipeline damage from navigating vessels.
(e) Geological restrictions to navigation over the pipeline, such as the proximity of a land mass or the presence of water much shallower than 15 feet.
(f) Results of previous underwater inspections of the pipeline.
(g) Changing conditions of the sea floor, such as scouring, shifting, mudslides, collapsing, and silting.

2 INSPECTION

2.1 Inspection frequencies and prioritization.

(a) Operators may use the information obtained in 1.2 above to establish the frequency for inspecting each pipeline.
(b) Operators should prioritize the order in which the pipelines may be inspected and inspect those of perceived higher risk first, and possibly more frequently.
(c) Pipelines that operators determine are at risk of becoming a hazard to navigation or becoming exposed should be inspected more often, but operators should establish intervals for repeating inspections based upon the risks.

2.2 Inspection methods.

Operators may employ any suitable method, or a combination of methods, for underwater pipeline inspection based upon conditions required by a pipeline's specific environment. Operators should consider the following methods.

(a) Divers.
(b) Ultrasound or sidescan sonar.
(c) Remotely operated underwater inspection devices or vehicles (e.g., ROVs).
(d) Photography.
(e) Probing.

3 REPORTING (§192.612(c)(1))

In addition to the reporting requirements of §192.612(c)(1), an operator should also consider including the following.
(a) Latitude and longitude of the pipeline end points.
(b) Offshore area name.
(c) Offshore block number.
(d) Name of water body.
(e) Name of parish or county.
(f) Other pertinent information.

4 REMEDIAL ACTION

If an operator is unable to meet the deadline for remediation, the required notification to OPS should be in writing.

§192.613

Continuing surveillance.

[Effective Date: 05/24/23]

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

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

(c) Following an extreme weather event or natural disaster that has the likelihood of damage to pipeline facilities by the scouring or movement of the soil surrounding the pipeline or movement of the pipeline, such as a named tropical storm or hurricane; a flood that exceeds the river, shoreline, or creek high-water banks in the area of the pipeline; a landslide in the area of the pipeline; or an earthquake in the area of the pipeline, an operator must inspect all potentially affected onshore transmission pipeline facilities to detect conditions that could adversely affect the safe operation of that pipeline.

(1) An operator must assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for the additional assessments required under this paragraph (c)(1).

(2) An operator must commence the inspection required by paragraph (c) of this section within 72 hours after the point in time when the operator reasonably determines that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection as determined by paragraph (c)(1) of this section are available. If an operator is unable to commence the inspection due to the unavailability of personnel or equipment, the operator must notify the appropriate PHMSA Region Director as soon as practicable.

(3) An operator must take prompt and appropriate remedial action to ensure the safe

operation of a pipeline based on the information obtained as a result of performing the inspection required by paragraph (c) of this section. Such actions might include, but are not limited to:

(i) Reducing the operating pressure or shutting down the pipeline;

(ii) Modifying, repairing, or replacing any damaged pipeline facilities;

(iii) Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;

(iv) Performing additional patrols, surveys, tests, or inspections;

(v) Implementing emergency response activities with Federal, State, or local personnel; or

(vi) Notifying affected communities of the steps that can be taken to ensure public safety.

[Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

Note: Although not required, operators should consider including Type B gathering lines in continuing surveillance efforts.

1 GENERAL

Continuing surveillance should be conducted to identify any pipeline facilities experiencing abnormal or unusual operating and maintenance conditions. This may be accomplished by the following.

(a) Periodic visual inspection of pipeline facilities to identify items such as the following.
  - (1) Changes in population densities.
  - (2) Effects of changes in topography.
  - (3) Effects of exposure or movement.
  - (4) Effects of encroachments.
  - (5) Specific circumstances relating to patrolling and leakage. See guide material under §§192.705, 192.706, 192.721, and 192.723.
  - (6) Potential for, or evidence of:
    - (i) Excavation activity.
      Note: If evidence of an excavation is found near a transmission pipeline covered segment, the location must be examined in accordance with §192.935(b)(1)(iv).
    - (ii) Tampering, vandalism, or damage.
    - (iii) Earth movement. See Guide Material Appendix G-192-13.
    - (iv) Flooding. See 6 below
    - (v) Mining activity. See Guide Material Appendix G-192-13.
    - (vi) Soil or water accumulation in vaults or pits.
    - (vii) Gas migration through air intakes into buildings from vaults and pits.
    - (viii) Excessive snow and ice build-up on aboveground facilities (e.g., meter sets, pressure control equipment, heaters) that could affect their function.

(b) Periodic review and analysis of records, such as the following.
  - (1) Patrols.
  - (2) Leak surveys.
  - (3) Valve inspections.
  - (4) Vault inspections.
  - (5) Pressure regulating, relieving, and limiting equipment inspections.
  - (6) Corrosion control inspections.
  - (7) Facility failure investigations.

Anomalies discovered should be evaluated, and those determined to present potential safety concerns should be scheduled for remediation and communicated to appropriate integrity management personnel.

2 CAST IRON PIPELINES

For cast iron pipelines, see Guide Material Appendix G-192-18.

3 PE PIPELINES

3.1 Brittle-like cracking.

(a) Some PE materials manufactured before 1982 have a lower resistance to the effects of induced stresses and are subject to brittle-like cracking under certain in-service conditions (e.g., rock impingement, squeeze-offs, severe bending moments). Brittle-like cracking is characterized by a part-through crack initiating in the pipe wall followed by slow crack growth causing failure. These failures result in a tight slit-like opening and a gas leak. This older generation of PE may have leak-free performance for a number of years before brittle-like cracks occur. An increase in the occurrence of leaks is typically the first indication of a brittle-like cracking problem.

(b) PE materials that are most known for this failure mode include the following.
- (1) Century Utility Products, Inc. products.
- (2) Low-ductile inner wall PE 2306 "Aldyl A" pipe manufactured by DuPont Company during 1970 through 1972, generally NPS 1¼ to NPS 4. To determine if the "Aldyl A" pipe has low-ductile inner wall, see 3(f) below.
- (3) PE gas pipe designated PE 3306.
- (4) DuPont PE tapping tees with DuPont Delrin® polyacetal (homopolymer) inserts (see 3(g) below).
- (5) Plexco PE service tees with Celanese Celcon® polyacetal (copolymer) caps (see 3(h) below).

(c) Conditions that may cause these types of materials to fail prematurely include the following.
- (1) Inadequate support and backfill during installation.
- (2) Tree root or rock impingement.
- (3) Shear and bending stresses due to differential settlement resulting from factors such as:
  - (i) Excavation in close proximity to PE piping.
  - (ii) Directional drilling in close proximity to PE piping.
  - (iii) Frost heave.
- (4) Bending stresses due to pipe installations with bends exceeding recommended practices.
- (5) Stresses where the pipe has been squeezed off.

(d) Each operator that has these older PE pipelines should consider the following practices.
- (1) Review system records to determine if any known susceptible materials have been installed in the system.
- (2) Perform more frequent inspection and leak surveys on systems that have exhibited brittle-like cracking failures of known susceptible materials.
- (3) Collect failure samples of PE piping exhibiting brittle-like cracking.
- (4) Record the print line from any piping that has been involved in a failure. The print line information can be used to identify the resin, manufacturer, and year of manufacture for plastic piping.
- (5) For systems where there is no record of the piping material, consider recording print line data when piping is excavated for other reasons. Recording the print line data can aid in establishing the type and extent of PE piping used in the system.
- (6) Develop procedures for taking appropriate action, including pipe replacement, to mitigate potential pipe failures.
- (7) Use a consistent record format to collect data on system failures. It is recommended that operators use a standard industry form developed for gathering data on plastic pipe failures to help trend and evaluate the extent of plastic pipe performance problems. For information about such form, visit the AGA website at www.aga.org under "Operations and Engineering/Plastic Piping Data Project."

(e) For those pipeline systems that contain products manufactured by Century Utility Products, Inc. between 1970 and 1973, the systems should be monitored and necessary replacements made for system integrity and public safety.

(f) An operator can determine if the PE 2306 "Aldyl A" piping manufactured by DuPont Company during 1970 through 1972 has low-ductile inner wall by using the following procedure.
- (1) Cut a ½-inch ring from the pipe.
- (2) Cut the ring at one point.

(3) Reverse bend the ring, exposing the inner surface of the pipe.
(4) Bend back the ring until the outer surfaces of the pipe (or cut ends) touch.
(5) Cracking on the inner surface of the ring in the bend area indicates low-ductile inner wall.

(g) DuPont PE tapping tees with Delrin polyacetal inserts were installed in gas systems from the late 1960s to the early 1980s and should be replaced as they are discovered. These can be distinguished by a black cap with male threads and a tan PE body.

(h) Plexco PE service tees with Celcon polyacetal caps were installed in gas systems prior to 1996. Caps that show marks from the use of a tool (e.g., pipe wrench or Channellock®-type pliers) on the cap should be replaced.

(i) References concerning brittle-like cracking in PE materials include the following.
(1) NTSB Reports
(i) PAB-98-02 available at www.ntsb.gov/investigations/AccidentReports/Pages/pipeline.aspx
(ii) SIR-98-01 available at www.ntsb.gov/safety/safety-studies/Pages/SafetyStudies.aspx
(2) OPS Advisory Bulletins (see Guide Material Appendix G-192-1, Section 2) as follows.
(i) ADB-99-01 (64 FR 12211, Mar. 11, 1999).
(ii) ADB-99-02 (64 FR 12212, Mar. 11, 1999).
(iii) ADB-02-07 (67 FR 70806, Nov. 26, 2002 with Correction, 67 FR 72027, Dec. 3, 2002).
(iv) ADB-07-02 (72 FR 51301, Sept. 6, 2007 with Correction, 73 FR 11192, Feb. 29, 2008).
(3) "Correlating Aldyl 'A' and Century PE Pipe Rate Process Method Projections with Actual Field Performance," E.F. Palermo, Ph.D., Plastics Pipes XII Conference, April 2004, available at www.aga.org/GPTC.

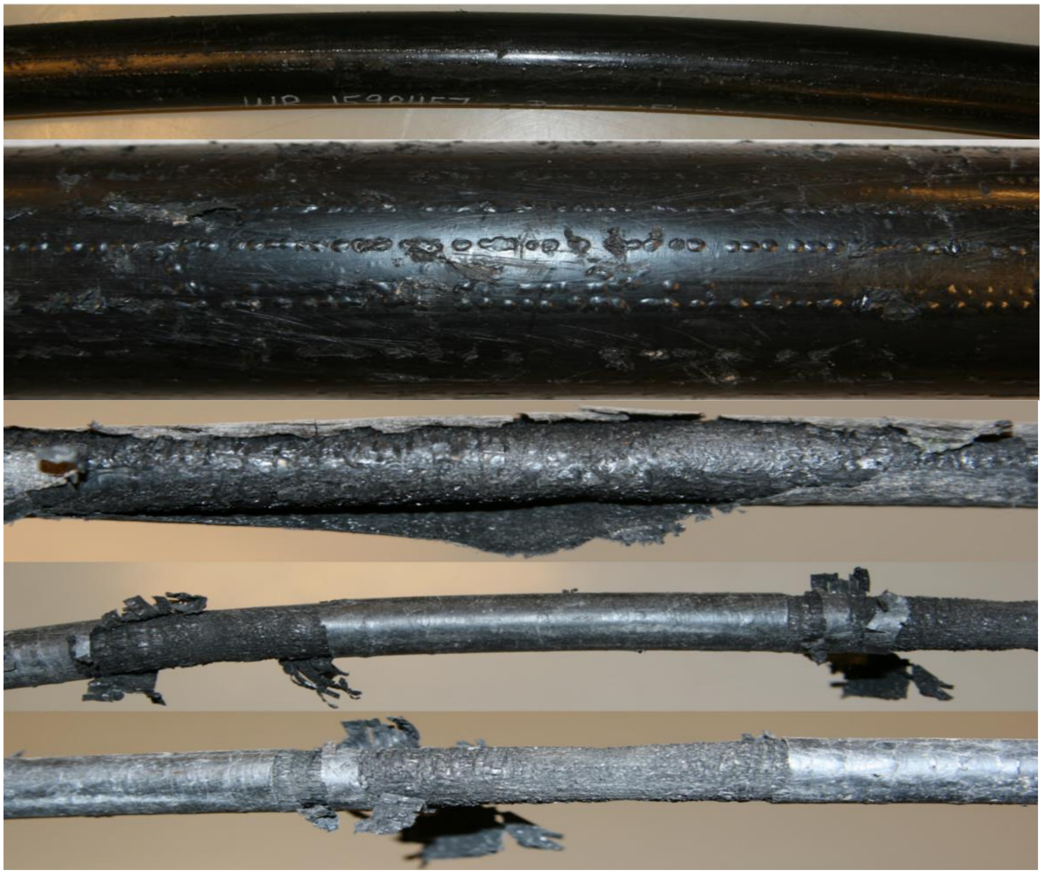
3.2 Degradation due to thermal oxidation.

Driscopipe® 7000 and 8000 high-density (HD) PE pipe exposed to prolonged elevated temperatures might degrade as a result of thermal oxidation. The mechanism for this oxidation appears to be the depletion of the thermal stabilizer, which has been shown to occur over time in regions of high ambient temperatures. There is no evidence that other PE piping products are similarly affected. Driscopipe® 7000 and 8000 HDPE pipes were produced from pipe materials that contained specific and unique additives.

(a) Based on laboratory testing and observed field performance, the regions of the U.S. that have the highest ambient temperature conditions are of particular concern.

(b) The potential for thermal oxidation of Dricopipe® 7000 and 8000 HDPE pipe increases as a function of elevated pipe temperature and exposure time. Segments of pipe that are not actively flowing gas such as service lines; CTS services (typically service lines) have experienced more leakage than IPS sizes (typically mains).

(c) Thermal oxidation might present as external degradation on the outside surface of the pipe or internal degradation on the inside surface of the pipe, or both.
(1) External degradation might be observed through visual inspection of the pipe or detected audibly by squeezing of the pipe (see 3.2(f) below). External degradation does not normally result in a loss of integrity or leakage, provided the material is still sound below the degraded surface.
(2) External degradation might pose operational concerns for the operator as joining of the pipe might require special fittings to avoid creating a source of leakage with externally sealing fittings. Operators are encouraged to consider externally degraded pipe segments for replacement. Another consideration is decreasing the maximum operating pressure of the pipe to account for wall loss attributed to external degradation.



Note: **Photographs of pipes provided with permission of the operator.**

INDUSTRY-RECOGNIZED MITIGATION METHODS	
Mitigation Method	**Description**
	corrosion failure. Examples include eddy current and electromagnetic acoustic transducer (EMAT) tools.
Engineering Critical Assessment	A written document that evaluates the risks of SCC and provides a technically defensible plan to demonstrate satisfactory pipeline safety performance. The document considers the defect growth mechanisms of the SCC process.

TABLE 192.613ii

5 THREADED JOINTS

Operators that have threaded joints in underground gas systems may want to determine if increased surveillance is warranted. Factors that could be considered include wall thickness, leak history, susceptibility to corrosion, settlement, frost-induced movement, and third-party damage.

6 SEVERE FLOODING

Severe flooding can adversely affect the safe operation of a pipeline. Operators should consider the following actions in areas prone to, or previously affected by, flooding.

(a) Identify pipeline facilities that are in the flood plain, such as overlaying 100-year flood elevations on GIS pipeline maps.

(b) For buried pipelines, consider the following.

(1) Using hydrologists or other experts in river flow to evaluate the potential for scour or channel migration that might affect the identified pipeline facilities.

(2) Evaluating terrain and vegetation conditions that can cause severe scouring of the watercourse. Such conditions could include burned areas subject to soil erosion and long-term buildup of debris and vegetation.

(3) Evaluating river or water crossings to determine if the pipeline installation method is sufficient to withstand the risks posed by areas prone to flooding, scour, or channel migration.

(4) Determining the maximum flow or flooding conditions at river or water crossings where pipeline integrity is at risk due to flooding or scouring and having contingency plans to shut down and isolate those pipelines when such conditions occur. Where appropriate, provide copies of the contingency plan and review with the pipeline controllers.

(5) Installing drainage measures in the trench to mitigate subsurface flows and enhance surface water draining at the site.

(6) Installing trench breakers and slope breakers to mitigate trench seepage and divert trench flows along ground surface to a safe discharge point off the site or right-of-way.

(c) For aerial or aboveground pipeline crossings, consider the potential for the following.

(1) Scouring of deadman anchors and tower foundations on cable-supported pipelines and traffic or pedestrian bridges.

(2) Floating debris impacting the pipeline and its supports beneath or on the upstream side of traffic or pedestrian bridges.

(d) Extend regulator vents and relief stacks above the level of anticipated flooding, as appropriate.

(e) Determine if facilities that are normally above ground (e.g., valves, regulators, relief devices) could become submerged and then have a potential for being struck by vessels or debris, and consider protecting or relocating such facilities.

(f) For additional information, see OPS Advisory Bulletins ADB-2019-01 (84 FR 14715, April 11, 2019; see Guide Material Appendix G-192-1, Section 2) regarding severe flooding and ADB-2019-02 (84 FR 18919, May 2, 2019; see Guide Material Appendix G-192-1, Section 2) regarding geological hazards.

7 SERVICE LINES UNDER BUILDINGS

Buried and uncased service lines discovered under buildings should be moved to locations no longer beneath the building or reinstalled under the building in accordance with the requirements of §192.361. In instances involving mobile homes, it may be possible to have the home relocated away from the service line. See guide material under §192.361.

8 INTEGRITY MANAGEMENT CONSIDERATIONS

Conditions or information discovered that could affect the integrity of a pipeline should be reported to the appropriate integrity management and operating personnel. Examples include the following.

(a) Evidence of one or more of the following
  (1) External corrosion.
  (2) Deteriorated coating.

(3) Maintaining minimum clearances of powered equipment from facilities.
(4) Preserving location markings.
(5) Practicing safe excavation and backfill procedures related to the protection of operator facilities. When a high risk condition is identified, the operator should consider locating the nearest valves or shut-off points necessary to isolate the site. The operator should check the operability of those valves and maintain as necessary (see guide material under §192.747).

(c) Settlement. The operator should pay particular attention, during and after excavation activities, to the possibility of joint leaks and breaks due to settlement when excavation activities occur, especially in cast iron, threaded-coupled steel, and mechanical-compression joints.
(d) Cast iron pipelines. See Guide Material Appendix G-192-18.
(e) Plastic and steel pipelines. The operator should inspect plastic pipelines for gouges and steel pipelines for coating damage and gouges, when necessary, before the exposed pipeline is backfilled. If metallic facilities are exposed during locating activities, see guide material under §192.459.
(f) Blasting. Leak surveys should be conducted on pipelines that could have been affected by blasting. For additional guidelines related to blasting activities, see Guide Material Appendix G-192-16.
(g) Trenchless installations. Leak surveys should be considered on pipelines that could be affected by trenchless installations. See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies.
(h) Damage concerns. When the operator is aware that its pipeline has been hit or almost hit, the excavator's practices and procedures that are likely to affect the operator's pipeline should be evaluated before excavation activity continues.
(i) Transmission lines. A reference for inspecting transmission lines is API RP 1166, "Excavation Monitoring and Observation."

2.9 Protection at active construction sites.
For temporary markings, see 4 of the guide material under §192.319.

§192.615

Emergency plans.

[Effective Date: 10/05/22]

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

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

(2) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9-1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. An operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies.

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

(i) Gas detected inside or near a building.
(ii) Fire located near or directly involving a pipeline facility.
(iii) Explosion occurring near or directly involving a pipeline facility.
(iv) Natural disaster.

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

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

(6) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released gas to life, property, or the environment.

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

(8) Notifying the appropriate public safety answering point (i.e., 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving a notification of potential rupture, as defined in §192.3, to coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of §§192.179, 192.634, or 192.636.

(9) Safely restoring any service outage.

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

(11) Actions required to be taken by a controller during an emergency in accordance with the operator's emergency plans and requirements set forth in §192.631, 192.634, and 192.636.

(12) Each operator must develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in §192.3, is an actual rupture event or a non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture and identify an actual rupture. For operators installing valves in accordance with §192.179(e), § 192.179(f), or that are subject to the requirements in §192.634, those procedures must provide for rupture identification as soon as practicable.

(b) Each operator shall:

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

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

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

(c) Each operator shall establish and maintain liaison with the appropriate public safety answering point (*i.e.,* 9-1-1 emergency call center) where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, as well as fire, police, and other public officials, to:

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

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

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

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

[Amdt. 192-24, 41 FR 13586, Mar. 31, 1976; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-112, 74 FR 63310, Dec. 3, 2009; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

GUIDE MATERIAL

GUIDE MATERIAL

1 GENERAL

The public education program should be tailored to the type of pipeline operation (transmission, distribution, gathering) and the environment traversed by the pipeline. Section 192.616(b) requires the operator to assess the unique attributes and characteristics of the operator's facilities. Operators in the same area should attempt to coordinate their program activities to properly direct reports of emergencies and to avoid inconsistencies.

Some activities performed as requirements for public awareness may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.620(d)(2), and 192.935.

Operators of petroleum gas distribution systems or smaller natural gas systems (e.g., master meter operators) subject to §192.616 should review the "Guidance Manual for Operators of LP Gas Systems" or the "Guidance Manual for Operators of Small Natural Gas Systems" available at https://www.phmsa.dot.gov/training/pipeline/guidance-manuals in addition to other references noted below.

2 API RP 1162

2.1 Recommended Practice (RP).

Guidance provided in API RP 1162 (see §192.7 for IBR) is represented as "recommended practices"; however, §192.616(b) and (c) require the operator to follow the general program recommendations of API RP 1162 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.

2.2 Stakeholder audiences.

Guidance is provided in API RP 1162, Section 3 for identifying the four stakeholder audiences, which are the affected public, emergency officials, local public officials with land use authority, and excavators. Some additional considerations for this identification process include the following.

(a) Residents located adjacent to a transmission or regulated gathering line ROW.
The extent of program coverage may vary depending on the location of the transmission or regulated gathering pipeline with respect to occupants of residences and businesses. In determining the scope of the operator's communication, the likelihood that the occupant would be able to recognize a pipeline emergency on the rights-of-way should be considered. Distance, terrain, other homes, or buildings between the occupant and the pipeline are factors that influence the ability to recognize a pipeline emergency. See 2.3(b) of the guide material under §192.614.

(b) Emergency officials and local public officials with land use authority.
See 2.3(c) of the guide material under §192.614.

(c) Excavators.
See 2.3(a) of the guide material under §192.614.

(d) Other audiences not specifically mentioned in API RP 1162.
  (1) Railroads. See 2.3(d) of the guide material under §192.614.
  (2) Operators of facilities in the vicinity of the pipeline (e.g., telephone, electric, gas, cable, water, sewer, and railroads). See 3 of the guide material under §192.615.

2.3 Message content.

API RP 1162 identifies several "Baseline Messages" and "Supplemental Messages" to be communicated to the stakeholder audiences. Operators are required by §192.616(b) and (c) to follow these general program recommendations, except as exempted by §192.616(c). It is often more effective to emphasize one or two messages at any given time rather than overwhelm the stakeholder audience with a "laundry list" that might be easily forgotten. If the operator chooses to convey the required messages in multiple communications to stakeholder audiences, the operator should consider including a plan, schedule, or timetable in its program for addressing each of the recommended messages.

Guidance is provided in API RP 1162, Section 4 for message content and components. Additional considerations for some of the message components include the following.

(a) Pipeline purpose — Facts about the gas distributed or transported.
(b) Leaks and pipeline emergencies – Transmission and regulated gathering lines.
  (1) Possible indicators might include the following.
    (i) A roaring, blowing, or hissing sound.
    (ii) Dirt being blown or appearing to be thrown into the air.
    (iii) Water bubbling or being blown in the air from water bodies or wet areas.
    (iv) Fire coming from the ground, appearing to burn right above the surface, or uncontrolled burning of gas.
    (v) Dead or dying vegetation on or near a ROW in an otherwise green area.
    (vi) Unusually dry or frozen spots on rights-of-way.
    (vii) An odor of gas.
  (2) Response to a pipeline leak or emergency.
    (i) Leave the area quickly and warn others to stay away.
    (ii) Report a leak or an emergency to the pipeline operator and local 911 or local emergency response agency from a safe place.
    (iii) Communicate periodic messages to the known excavator community in their territory. The message should inform excavators of the requirement to promptly report damages that result in the release of gas (especially if required by state regulations) to appropriate emergency response authorities by calling 911 (49 CFR §196.109) or, where there is no local 911, the local emergency response agency.
    (iv) Actions to take until the operator can respond. These might include the following.
      (A) Do not attempt to operate pipeline valves.
      (B) Do not use open flames or bring anything into the area that may cause ignition (e.g., cell phones, flashlights, motor vehicles, electric or cordless tools).
      (C) Continue to warn others to stay away from the area.
(c) Leaks and pipeline emergencies — Distribution systems.
  (1) Possible indicators might include the following.
    (i) An odor of gas in a building.
    (ii) An odor of gas outside.
    (iii) An odor of gas where excavation work is in progress or has recently been completed.
    (iv) A hissing, roaring, or blowing sound.
    (v) Blowing or uncontrolled burning of gas.
    (vi) Water bubbling or being blown in the air from water bodies or wet areas.
    (vii) A fire in or near a gas appliance or piping.
    (viii) Unusual noise at an appliance.
    (ix) Unusual behavior of the flame at an appliance burner.
  (2) Response to a pipeline leak or emergency.
    (i) Importance of reporting any odor of gas no matter how slight.
    (ii) Report an odor or emergency to the system operator.
    (iii) Communicate periodic messages to the known excavator community in their territory. The message should inform excavators of the requirement to promptly report damages that result in the release of gas (especially if required by state regulations) to appropriate emergency response authorities by calling 911 (49 CFR §196.109) or, where there is no local 911, the local emergency response agency.
    (iv) Actions to take until the operator can respond. These might include the following.
      (A) Do not attempt to locate gas leaks.
      (B) Do not remain in the building when there is a strong gas odor, and tell other occupants to evacuate.
      (C) Do not turn lights on or off or unplug electrical appliances when there is a strong gas odor.

(D) Do not use telephones in the area of a strong gas odor.
(E) Do not use elevators.
(F) Do not attempt to operate a valve on a main.
(G) Do not position or operate vehicles or powered equipment where leaking gas may be present.
(H) Do not smoke or use lighters, matches, or other open flames.
(I) Notify the local emergency response agency, such as the fire or police department (call 911 where applicable), regarding the emergency situation if gas leakage is determined to be significant (blowing or burning).

(d) Priority to protect life.
Emphasize that personal safety and the protection of human life should always be given higher priority than protection of property.
(e) Damage prevention.
See 2.5 of the guide material under §192.614.

2.4 Additional information.

Distribution, transmission, gathering, and underground storage operators may choose to include additional messages for preventing, recognizing, and reporting types of hazards or potential hazards not addressed by API RP 1162, such as the following.

(a) Heavy snow accumulation on meter set assemblies and a safe method of snow removal from meter set assemblies to prevent equipment damage (e.g., use of a broom instead of a shovel).
(b) Snow or ice falling or being shoveled from roofs onto gas facilities.
(c) Ice buildup on regulators or regulator vents.
(d) Carbon monoxide hazards from snow and ice buildup around combustion air and exhaust vents for gas appliances.
(e) Flooding that might affect gas facilities.
(f) Possibility of cross bores when sewer clearing activities are being conducted.
(g) Non-leaking damage to pipelines and other facilities.
(h) Damage to pipe surface, pipe wrap, or pipe coating due to scrapes or gouges.
(i) Planned rolling electric system blackouts or unplanned electric system outages, large-scale or small-scale, might result in the interruption of gas service. The duration of the gas service interruption might exceed the duration of the electric system outage due to the turn-on and turn-off process of gas restoration.

2.5 Message delivery methods.

Guidance is provided in API RP 1162, Section 5 for several delivery methods and tools available for communicating with the stakeholder audiences. See 2.4 of the guide material under §192.614 for additional information regarding delivery methods for excavators and the affected public. However, the operator is required by §192.616(c) to justify in its program or procedural manual if it does not follow the general program recommendations of API RP 1162 regarding message delivery methods.

3 LANGUAGE

The following may provide indications of languages in addition to English to consider when conducting public education programs.

(a) Languages prescribed by state or local governments.
(b) Commercial non-English radio, television, and print media.
(c) U.S. Census data.

4 PROGRAM EFFECTIVENESS EVALUATION

See Guide Material Appendix G-192-3.

5 REFERENCES

(a) Information regarding public education programs, such as FAQs and Workshops, is available at https://primis.phmsa.dot.gov/comm/PublicAwareness/PublicAwareness.htm.

(b) OPS Advisory Bulletins (see Guide Material Appendix G-192-1, Section 2) as follows.
   (1) ADB-93-01 (58 FR 7034, Feb. 3, 1993).
   (2) ADB-97-01 (Issued in Kansas City, MO on Jan.24, 1997).
   (3) ADB-08-03 (73 FR 12796, Mar. 10, 2008).
   (4) ADB-11-02 (76 FR 7238, Feb. 9, 2011).

§192.617

Investigation of failures and incidents.

[Effective Date: 10/05/22]

(a) *Post-failure and incident procedures*. Each operator must establish and follow procedures for investigating and analyzing failures and incidents as defined in §191.3, including sending the failed pipe, component or equipment for laboratory testing or examination, where appropriate, for the purpose of determining the causes and contributing factor(s) of the failure or incident and minimizing the possibility of a recurrence.

***(b) Post failure and incident lessons learned.* Each operator must develop, implement, and incorporate lessons learned from a post-failure or incident review into its written procedures, including personnel training and qualification programs, and design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications.**

(c) *Analysis of rupture and valve shut-offs*. If an incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the closure of a rupture-mitigation valve (RMV), as defined in §192.3, or the closure of alternative equivalent technology, the operator of the pipeline must also conduct a post-incident analysis of all the factors that may have impacted the release volume and the consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. The requirements of this paragraph (c) are not applicable to distribution pipelines or Types B and C gas gathering pipelines.

The analysis must include all relevant factors impacting the release volume and consequences, including, but not limited to, the following:

(1) Detection, identification, operational response, system shut-off, and emergency response communications, based on the type and volume of the incident;

(2) Appropriateness and effectiveness of procedures and pipeline systems, including supervisory control and data acquisition (SCADA), communications, valve shut-off, and operator personnel;

(3) Actual response time from identifying a rupture following a notification of potential rupture as defined at §192.3, to initiation of mitigative actions and isolation of the pipeline segment, and the appropriateness and effectiveness of the mitigative actions taken;

(4) Location and timeliness of actuation of RMVs or alternative equivalent technologies; and

(5) All other factors the operators deems appropriate.

(d) *Rupture post-failure and incident summary*. If the failure or incident on an onshore gas transmission pipeline or a Type A gathering pipeline involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV (as those terms are defined in §192.3), or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by paragraph (c) of this section within 90 days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. The final post-failure or incident summary, and all other reviews and analyses produced under the requirements of this section, must be reviewed, dated, and signed by the operator's appropriate senior executive officer. The final post-failure or incident summary, all investigation and analysis documents used to prepare it, and records of lessons learned must be kept for the useful life of the pipeline. The requirements of this paragraph (d) are not applicable to distribution pipelines or Types B and C gas gathering pipelines.

[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

GUIDE MATERIAL

Note: Although not required, operators should consider developing written procedures for failure investigations on Type B gathering lines.

1 GENERAL

(a) Data on all failures and leaks should be compiled to support compliance with §192.613. A failure investigation should be performed to determine the cause of the failure and minimize the possibility of a recurrence.
(b) For information on failures of PE pipe, see 3 of the guide material under §192.613.
(c) For information on reporting failures of mechanical fittings, see guide material under §191.12.

2 TYPES AND NATURE OF FAILURES THAT SHOULD BE ANALYZED

Failure investigation should be conducted for incidents as defined in §191.3. An operator should also consider investigating any other failure that enables the operator to establish patterns that might be occurring on its pipeline system. For examples, see guide material under §192.613.

3 FAILURE INVESTIGATION

(a) Failure investigation and subsequent analysis should determine the root cause(s) of the failure. The investigation may be as simple as assembling an internal review group or as complex as conducting a full-scale failure investigation with laboratory analysis of a failed component. The information for completing a 30-day incident report form contained in Part 191 may constitute an adequate analysis of a reportable failure or leak. See §§191.9 and 191.15.
(b) The general process for performing root-cause analysis is as follows.
  (1) Assemble the review team.
  (2) Define the problem and gather data and documentation.
  (3) Identify factors that contributed to the problem (i.e., causal factors).
  (4) Find the root cause for each causal factor, such as people, equipment, material, process, or outside influence.
  (5) Develop and assign recommendations.
  (6) Distribute recommendations and review the operator's procedures.
  (7) Implement the recommendations.
(c) For failures of mechanical fittings or joints, consider following the evaluation steps in 3 of the guide material under §191.12.

4 RESPONSE TO FAILURE

If a detailed analysis is to be made, rapid response will be necessary for preserving the integrity of specimens and gathering information.

5 DATA COLLECTION

5.1 Incident.
When a detailed analysis is to be made, a person at the scene of the incident should be designated to coordinate the investigation. That person's responsibilities should include the following.
(a) Acting as a coordinator for all field investigative personnel.
(b) Maintaining a log of the personnel, equipment, and witnesses.
(c) Recording in chronological order the events as they take place.
(d) Ensuring that photographs are taken of the incident and surrounding areas. These photographs may be of great value in the investigation.
(e) Ensuring the notification of all appropriate governmental authorities.
(f) Ensuring the preservation and chain of custody of evidence.
5.2 Other failures.
(a) Gather sufficient data to complete the general process for performing root-cause analysis. See 3

abnormal situation, who that controller should notify and what information should be provided. The protocol should include communication requirements for an abnormal situation discovered by the controller or by field personnel. Information regarding the situation should be recorded and include the persons notified and the information provided.

(v) Recordkeeping requirements for these abnormal situations for further review and training purposes as specified in 7 below. (Transmission operators should already have recordkeeping requirements in place per §192.605(c)).

(c) Emergency operating conditions.

(1) Types of emergency operating conditions might include the following.

(i) Overpressurization.

(ii) Low pressure.

(iii) Sudden pressure drop.

(iv) Activation of an emergency shutdown (ESD) device.

(v) Report of blowing gas, fire, or explosion.

(vi) Weather-related events (e.g., flood, tornado, hurricane) that cause damage to a pipeline facility or result in planned rolling electric system blackouts or unplanned electric system outages.

(vii) Hazardous leak.

(viii) Report of gas in a building and emergency evacuation.

(2) Procedures should contain the following.

(i) A description of operations that would constitute an emergency operating condition or situation.

(ii) Actions that should be taken by a controller upon becoming aware of an emergency situation. (These emergency situations may be partially addressed in the operator's Emergency Plan.)

(iii) A definition of roles, responsibilities, and actions that a controller may take without supervisory approval. All actions should be to protect people first and then property.

(iv) A communications protocol that designates, upon a controller becoming aware of an emergency situation, who that controller should notify and what information should be provided. The protocol should include communication requirements for an emergency situation discovered by the controller or field personnel. Information regarding the situation should be recorded and include the persons notified and the information provided.

(v) Required communications and approvals needed before returning to normal operations.

(vi) Recordkeeping requirements for these events for further review and training purposes as specified in 7 below. Recordkeeping requirements for reportable incidents may be addressed with written procedures for §§191.9 or 191.15.

3.3 Communications.

Communication issues may also be addressed in management of change (MOC) and training in 6 and 7 below.

(a) Communication protocols.

Consideration should be given to the timeliness, type, and amount of information to be passed on to both internal and external entities, and designation of the person responsible for the communication. Internal entities may include other controllers, both on shift and between shifts, and other operator personnel outside of the control room environment such as field technicians, supervisors, and management. External entities may include suppliers, customers, local emergency personnel, electric providers operating within the gas system territory, the National Response Center (NRC), or regulatory agencies.

(b) Control room shift change communication.

Shift change communications should not be limited to scheduled changeovers, but should also include emergency and unanticipated changes due to illnesses, personal emergencies, routine breaks, and meals. Shift change communications may need to be tailored for those control rooms that do not operate on a continuous 24-hour basis.

(c) Procedures should contain the following.
   (1) A process to record shift changes between controllers, including names and times of changes. This can be a paper or electronic logbook, a SCADA system login, a checklist, or some other process.
   (2) Information that is required to be passed on from the outgoing controller to the incoming controller, which might include the following.
      (i) Ongoing emergencies or abnormal operations.
      (ii) Upcoming pipeline operations that might occur during upcoming shifts.
      (iii) Routine operating information, such as flow, linepack, and customer requirements.
      (iv) Pipelines or facilities out of service, such as a storage field.
      (v) Maintenance activities.
      (vi) Pigging operations.
      (vii) Unusual flow conditions, such as pipelines with reduced MAOPs or gas quality issues.
      (viii) Weather-related events.
      (ix) Alarms or conditions being investigated.
      (x) Communication outages (e.g., no SCADA data) and manned locations.
      (xi) Other unusual operations.

(d) Other internal communications.
   Communications procedures should define events that require communication between field operations or customer service and the control room. Communication becomes especially important prior to non-routine events. These events may include the following.
   (1) Outages.
   (2) Maintenance activities, including line blowdowns, service restoration, and storage fields going off and on line.
   (3) Pigging operations.
   (4) Starting/stopping compressor units.
   (5) Changes in regulator set points.
   (6) Variations in flow.
   (7) Retired equipment going off line or new equipment being put into service.

(e) External communications.
   Communications procedures should address and establish guidelines for dealing with first responder personnel, media or the public, especially during emergencies. Often the control room phone number is the emergency number posted on operator facilities. Depending on the number of calls per day, an operator may want to consider using non-controller personnel to handle the public communications or providing additional workers during emergency situations. The operator should consider the following in its external communications protocols.
   (1) Determining the nature and priority of the contact.
   (2) Providing additional information.
   (3) Notifying appropriate operator personnel.
   (4) Notifying emergency officials, if required.
   (5) Notifying other external entities.
   (6) Documenting communication and actions taken.

3.4 Manual pipeline operation.

(a) In the event that the SCADA system becomes non-operational, operators are required to have a communications plan in place to operate the pipeline manually (§192.631(c)(3)). The plan should include provisions to notify other operator personnel, with defined tasks for field personnel. The plan may be part of an emergency plan, incident plan, disaster plan, or similar to plans developed for the year 2000 problem (Y2K). The operator should consider items such as the following.
   (1) Critical locations that need to be monitored.
   (2) Means of communicating (e.g., landlines, texting, radios).
   (3) Availability of workforce and call-out lists.
   (4) Means of recording critical communications.

(5) Means of recording critical operational data.
(6) Frequency of communications.

(7) Approvals or oversight of operations.

(b) Section 192.631(c)(3) requires that operators test the manual operation communications procedure each calendar year. An operator may choose to perform the test as a single event or in multiple stages, depending on the operational requirements of the system. If an operator chooses to test in multiple stages, testing should ensure overlap of areas to confirm that all points within a pipeline system are included.

4 SUPERVISORY CONTROL AND DATA ACQUISITION SYSTEMS

4.1 General.

SCADA systems provide controllers with important tools to perform their roles and responsibilities. These tools include instrumentation for monitoring pipeline operating conditions and for operating pipeline equipment. SCADA systems may generate an alarm when an event has occurred or an unusual situation is developing.

The following are the primary components of a SCADA system, with definitions or examples of each.

(a) Field devices.
   (1) Pressure transmitters.
   (2) Temperature transmitters.
   (3) Flow computers or totalizers.
   (4) Gas chromatographs.
   (5) Gas stream analyzers (e.g., moisture, H2S).
   (6) Valve actuators.
   (7) Pressure regulator actuators.
   (8) Mechanical devices that control compressor engines.

   Note: Devices that lack communication capability with the control room, such as pressure recorders, gauges, or other field devices that only monitor the pipeline, are not considered part of SCADA.

(b) Data gathering and transmitting equipment.
   This equipment is comprised of computer hardware used to collect data from various field devices and format it for transmittal to a SCADA host computer, or receive and process instructions from a SCADA host computer. This equipment can also receive and process data from field devices and initiate pre-programmed instructions. An operator may choose how often data is transmitted to the system. Commonly used devices include the following.
   (1) Remote terminal units (RTUs).
   (2) Programmable logic controllers (PLCs).

(c) Communications processes.
   These are modes, protocols, and equipment used to transmit data between data-gathering equipment and the SCADA host computer. Modes of communication include the following.
   (1) Radio.
   (2) Wired phone (e.g., leased-line, dial-up, operator-owned).
   (3) Cellular.

(4) Intranet.
   (5) Internet.
   (6) Satellite.
   (7) Microwave.

(d) SCADA host computer and software.
   This processing or computing equipment and overlaying software programming is used to provide a link between the field or data-acquisition equipment and the controller interface.

(e) Controller interface.
   Equipment such as computer displays and human-machine interfaces (HMI) used by controllers to interact with field equipment or monitor the information gathered by the SCADA system.

(f) Data-acquisition equipment.
   Computer hardware and software used in conjunction with the SCADA system for storing historical

§192.634
Transmission lines: Onshore valve shut-off for rupture mitigation.
[Effective Date: 10/05/2022]

(a) *Applicability*. For new or entirely replaced onshore transmission pipeline segments with diameters of 6 inches or greater that are located in high-consequence areas (HCA) or Class 3 or 4 locations and that are installed after April 10, 2023, an operator must install or use existing rupture-mitigation valves (RMV), or an alternative equivalent technology, according to the requirements of this section and §§192.179 and 192.636. RMVs and alternative equivalent technologies must be operational within 14 days of placing the new or replaced pipeline segment into service. An operator may request an extension of 14-day operation requirement if it can demonstrate to PHMSA, in accordance with the notification procedures in §192.18, that application of that requirement would be economically, technically, or operationally infeasible. The requirements of this section apply to all applicable pipe replacement projects, even those that do not otherwise involve the addition or replacement of a valve. This section does not apply to pipe segments in Class 1 or Class 2 locations that have a potential impact radius (PIR)m as defined in §192.903, that is less than or equal to 150 feet.

(b) *Maximum spacing between valves*. RMVs, or alternative equivalent technology, must be installed in accordance with the following requirements:

(1) *Shut-off Segment.* For purposes of this section, a "shut-off segment" means the segment of pipe located between the upstream valve closest to the upstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment and the downstream valve closest to the downstream endpoint of the new or replaced Class 3 or Class 4 or HCA pipeline segment so that the entirety of the segment that is within the HCA or the Class 3 or Class 4 location is between at least two RMVs or alternative equivalent technologies. If any crossover or lateral pipe for gas receipts or deliveries connects to the shut-off segment between the upstream and downstream valves, the shut-off segment also must extend to a valve on the crossover connection(s) or lateral(s), such that, when all valves are closed, there is no flow path for gas to be transported to the rupture site (except for residual gas already in the shut-off segment). Multiple Class 3 or Class 4 locations or HCA segments may be contained within a single shut-off segment. The operator is not required to select the closest valve to the shut-off segment as the RMV, as that term is defined in §192.3, or the alternative equivalent technology. An operator may use a manual compressor station valve at a continuously manned station as an alternative equivalent technology, but it must be able to be closed within 30 minutes following rupture identification, as that term is defined at §192.3. Such a valve used as an alternative equivalent technology would not require a notification to PHMSA in accordance with §192.18.

(2) *Shut-off segment valve spacing*. A pipeline subject to paragraph (a) of this section must have RMVs or alternative equivalent technology on the upstream and downstream side of the pipeline segment. The distance between RMVs or alternative equivalent technologies must not exceed:

(i) 8 miles for any Class 4 location,
(ii) 15 miles for any Class 3 location, or
(iii) 20 miles for all other locations.

(3) *Laterals*. Laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs or alternative equivalent technologies that meet the actuation requirements of this section at locations other than mainline receipt/delivery points, as long as all the laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are 12 inches in diameter or less, a check valve that allows gas to flow freely in one direction and contains a mechanism to automatically prevent flow in the other direction may be used as an alternative equivalent technology where it is positioned to stop flow into the shut-off segment. Such check valves that are used as an alternative equivalent technology in accordance with this paragraph are not subject to § 192.636,

but they must be inspected, operated, and remediated in accordance with § 192.745, including for closure and leakage to ensure operational reliability. An operator using such a check valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179 develop and implement maintenance procedures for such equipment that meet § 192.745.

(4) *Crossovers*. An operator may use a manual valve as an alternative equivalent technology in lieu of an RMV for a crossover connection if, during normal operations, the valve is closed to prevent the flow of gas by the use of a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. The operator must develop and implement operating procedures and document that the valve has been closed and locked in accordance with the operator's lock-out and tag-out procedures to prevent the flow of gas. An operator using such a manual valve as an alternative equivalent technology must notify PHMSA in accordance with §§ 192.18 and 192.179.

(c) *Manual operation upon identification of a rupture*. Operators using a manual valve as an alternative equivalent technology as authorized pursuant to §§192.18 and 192.179 must develop and implement operating procedures that appropriately designate and locate nearby personnel to ensure valve shut-off in accordance with this section and §192.636. Manual operation of valves must include time for the assembly of necessary operating personnel, the acquisition of necessary tools and equipment, driving time under heavy traffic conditions and at the posted speed limit, walking time to access the valve, and time to shut off all valves manually, not to exceed the maximum response time allowed under §192.636(b).

[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

GUIDE MATERIAL

This guide material is under review following Amendment 192-130.

§192.635

Notification of potential rupture.

[Effective Date: 10/05/2022]

(a) As used in this part, a "notification of potential rupture" refers to the notification of, or observation by, an operator (e.g., by or to its controller(s) in a control room, field personnel, nearby pipeline or utility personnel, the public, local responders, or public authorities) of one or more of the below indicia of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline:

(1) An unanticipated or unexplained pressure loss outside of the pipeline's normal operating pressures, as defined in the operator's written procedures. The operator must establish in its written procedures that an unanticipated or unplanned pressure loss is outside of the pipeline's normal operating pressures when there is a pressure loss greater than 10 percent occurring within a time interval of 15 minutes or less, unless the operator has documented in its written procedures the operational need for a greater pressure-change threshold due to pipeline flow dynamics (including changes in operating pressure, flow rate, or volume), that are caused by fluctuations in gas demand, gas receipts, or gas deliveries; or

(2) An unanticipated or unexplained flow rate change, pressure change, equipment function, or other pipeline instrumentation indication at the upstream or downstream station that may be representative of an event meeting paragraph (a)(1) of this section; or

(3) Any unanticipated or unexplained rapid release of a large volume of gas, a fire, or an explosion in the immediate vicinity of the pipeline.

(b) A notification of potential rupture occurs when an operator first receives notice of or observes an event specified in paragraph (a) of this section.

[Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

GUIDE MATERIAL

1 GENERAL

Transmission lines and Type A gathering lines should be patrolled, as necessary, to observe factors affecting safe operation and to enable correction of potentially hazardous conditions. In addition to visual evidence of leakage, patrol considerations should include observation and reporting of potential hazards and conditions such as the following.

(a) Excavation, grading, demolition, or other construction activity that could result in the following.
  (1) Damage to the pipe.
  (2) Loss of support due to settlement or shifting of soil around the pipe.
  (3) Undermining or damage to pipe supports.
  (4) Loss of cover.
  (5) Excessive fill.
(b) Evidence that excavation, grading, demolition, or other construction activity may take place or has taken place, such as power equipment staged in the vicinity of transmission facilities or a freshly backfilled excavation over or near transmission facilities.
(c) Physical deterioration of exposed piping, pipeline spans, and structural pipeline supports, such as bridges, piling, headwalls, casings, and foundations.
(d) Land subsidence, downslope land movement, soil erosion, extensive tree root growth, flooding, climatic conditions, and other natural causes that can result in impressed secondary loads.
(e) Need for additional transmission pipeline identification and marking in private rights-of-way and in rural areas.
(f) Damage to casing vents and leakage from encased pipe.
(g) Areas of continual earth-moving activities, such as quarries and industrial plants, which may require special attention.
(h) Indications along a pipeline route that may trigger the need for the operator to conduct a class location study under §192.609. Examples of such indications include the following.
  (1) Changes in the number of buildings intended for human occupancy.
  (2) New buildings, or changes in use for existing buildings.
  (3) Changes in land use.
    (i) Playgrounds.
    (ii) Camps and campgrounds.
    (iii) Recreational areas.

2 SCHEDULING

2.1 General.
Patrolling may be accomplished in conjunction with leak surveys, scheduled inspections, and other routine activities.

2.2 Potentially hazardous locations.
Locations or areas that are considered potentially hazardous may be patrolled more frequently based on the probable severity, timing, and duration of the hazard.

3 METHOD

(a) Where practical, the patrol map or other documents (e.g., aerial photographs) used by the person making the patrol should identify areas near the transmission line that might require special attention. These areas might include locations where earthmoving activities are regularly performed, or where there are indications such as those listed under 1(h) above.

(b) Consider using a method for the patrol person to compare current conditions with conditions observed during previous patrols.

(c) For areas prone to slippage, landslides, or other geological movement, consider the following monitoring techniques.
  (i) Satellites or unmanned aerial vehicles (e.g., drones).
  (ii) Increasing the frequency of patrols paying particular attention to indications of displaced vegetation, exposed soil, or other indications of ground movement.
  (iii) Identifying geodetic monitoring points (e.g., survey benchmarks).

4 REPORTS

Patrol reports should indicate hazardous conditions observed, corrective action taken or recommended, and the nature and location of any deficiencies. These reports should also include information about population density near the right-of-way, including indications such as those listed under 1(h) above.

5 FOLLOW-UP

In those areas where excavation equipment is used on an on-going basis, such as quarries and some industrial plants, consideration should be given to providing those excavators more frequent damage prevention and public education notification. See guide material under §§192.614 and 192.616.

§192.706

Transmission lines: Leakage surveys.

[Effective Date: 02/11/95]

Leakage surveys of a transmission line must be conducted at intervals not exceeding 15 months, but at least once each calendar year. However, in the case of a transmission line which transports gas in conformity with §192.625 without an odor or odorant, leakage surveys using leak detector equipment must be conducted —

(a) In Class 3 locations, at intervals not exceeding 7½ months, but at least twice each calendar year; and

(b) In Class 4 locations, at intervals not exceeding 4½ months, but at least four times each calendar year.

[Issued by Amdt. 192-21, 40 FR 20279, May 9, 1975; Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994]

GUIDE MATERIAL

The minimum frequency for leakage surveys of transmission lines and gathering lines is established by §192.706. See 4 and Table 192.935i of the guide material under §192.935 for transmission pipelines operating below 30% of SMYS located in Class 3 or Class 4 location, but not in a high consequence area. See 1.3, 1.4, and 1.5 of the guide material under §192.723 and the applicable sections of Guide Material Appendix G-192-11.

Leakage surveys of Type B gathering lines require the use of leakage detection equipment (§192.9(d)(8)).

§192.707

Line markers for mains and transmission lines.

[Effective Date: 07/13/98]

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

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

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

(b) *Exceptions for buried pipelines.* Line markers are not required for the following pipelines:

(1) Mains and transmission lines located offshore, or at crossings of or under waterways and other bodies of water.

(2) Mains in Class 3 or Class 4 locations where a damage prevention program is in effect under §192.614.

(3) Transmission lines in Class 3 or 4 locations until March 20, 1996.

(4) Transmission lines in Class 3 or 4 locations where placement of a line marker is impractical.

(c) *Pipelines aboveground.* Line markers must be placed and maintained along each section of a main and transmission line that is located aboveground in an area accessible to the public.

(d) *Marker warning.* The following must be written legibly on a background of sharply contrasting color on each line marker.

(1) The word "Warning," "Caution," or "Danger" followed by the words "Gas (or name of gas transported) Pipeline" all of which, except for markers in heavily developed urban areas, must be in letters at least 1 inch (25 millimeters) high with 1/4 inch (6.4 millimeters) stroke.

(2) The name of the operator and the telephone number (including area code) where the operator can be reached at all times.

[Amdt. 192-20, 40 FR 13502, Mar. 27, 1975 with Amdt. 192-20A, 41 FR 56807, Dec. 30, 1976; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976 with Amdt. 192-27 Correction, 41 FR 39752, Sept. 16, 1976; Amdt. 192-40, 47 FR 13818, Apr. 1, 1982; Amdt. 192-44, 48 FR 25206, June 6, 1983; Amdt. 192-73, 60 FR 14646, Mar. 20, 1995; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1. GENERAL

(a) If an existing pipeline has undergone a conversion, its pipeline markers should be updated to accurately list natural gas as the product being transported.

(b) See Guide Material Appendix G-192-13, Section 3.

§192.709

Transmission lines: Record keeping.

[Effective Date: 07/08/96]

Each operator shall maintain the following records for transmission lines for the periods specified:

(a) The date, location, and description of each repair made to pipe (including pipe-to-pipe connections) must be retained for as long as the pipe remains in service.

(b) The date, location, and description of each repair made to parts of the pipeline system other

than pipe must be retained for at least 5 years. However, repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained in accordance with paragraph (c) of this section.

(c) A record of each patrol, survey, inspection, and test required by subparts L and M of this part must be retained for a least 5 years or until the next patrol, survey, inspection, or test is completed, whichever is longer.

[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]

GUIDE MATERIAL

See Guide Material Appendix G-192-17 for the explicit requirements of each patrol, survey, inspection, or test required by Subparts L and M. Also, see guide material under §192.947 for records required under Subparts I, L, and M to be used as part of the operator's Integrity Management Program for transmission lines.

§192.710

Transmission lines: Assessments outside of high consequence areas.

[Effective Date: 05/24/23]

(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, 192.712, 192.713, and 192.714 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.

[Amdt. 192-125, Oct. 01, 2019, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

This guide material is under review following Amendment 192-125

§192.711

Transmission lines: General requirements for repair procedures.

[Effective Date: 05/24/23]

(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) (i) Non-integrity management repairs for gathering lines and offshore transmission lines: For gathering lines subject to this section in accordance with § 192.9 and for offshore transmission lines, an operator must make permanent repairs as soon as feasible.

(ii) Non-integrity management repairs for onshore transmission lines: Except for gathering lines exempted from this section in accordance with § 192.9 and offshore transmission lines, after May 24, 2023, whenever an operator discovers any condition that could adversely affect the safe operation of a pipeline segment not covered by an integrity management program under subpart O of this part, it must correct the condition as prescribed in § 192.714.

(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.

[Amdt. 192-27B, 45 FR 3272, Jan. 17, 1980; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

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 and critical strain level.

[Effective Date: 05/24/23]

(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.

(1) If an operator would choose to use a remaining strength calculation method that could provide a less conservative result than the methods listed in paragraph (b) introductory

text, the operator must notify PHMSA in advance in accordance with § 192.18(c).

(2) The notification provided for by paragraph (b)(1) of this section must include a comparison of its predicted failure pressures to R-STRENG or ASME/ANSI B31G, all burst pressure tests used, and any other technical reviews used to qualify the calculation method(s) for varying corrosion profiles.

(c) *Dents and other mechanical damage.* To evaluate dents and other mechanical damage that could result in a stress riser or other integrity impact, an operator must develop a procedure and perform an engineering critical assessment as follows:

(1) Identify and evaluate potential threats to the pipe segment in the vicinity of the anomaly or defect, including ground movement, external loading, fatigue, cracking, and corrosion.

(2) Review high-resolution magnetic flux leakage (HR-MFL) high-resolution deformation, inertial mapping, and crack detection inline inspection data for damage in the dent area and any associated weld region, including available data from previous inline inspections.

(3) Perform pipeline curvature-based strain analysis using recent HR-Deformation inspection data.

(4) Compare the dent profile between the most recent and previous in-line inspections to identify significant changes in dent depth and shape.

(5) Identify and quantify all previous and present significant loads acting on the dent.

(6) Evaluate the strain level associated with the anomaly or defect and any nearby welds using Finite Element Analysis, or other technology in accordance with this section. Using Finite Element Analysis to quantify the dent strain, and then estimating and evaluating the damage using the Strain Limit Damage (SLD) and Ductile Failure Damage Indicator (DFDI) at the dent, are appropriate evaluation methods.

(7) The analyses performed in accordance with this section must account for material property uncertainties, model inaccuracies, and inline inspection tool sizing tolerances.

(8) Dents with a depth greater than 10 percent of the pipe outside diameter or with geometric strain levels that exceed the lessor of 10 percent or exceed the critical strain for the pipe material properties must be remediated in accordance with §§ 192.713, 192.714, or 192.933, as applicable.

(9) Using operational pressure data, a valid fatigue life prediction model that is appropriate for the pipeline segment, and assuming a reassessment safety factor of 5 or greater for the assessment interval, estimate the fatigue life of the dent by Finite Element Analysis or other analytical technique that is technically appropriate for dent assessment and reassessment intervals in accordance with this section. Multiple dent or other fatigue models must be used for the evaluation as a part of the engineering critical assessment.

(10) If the dent or mechanical damage is suspected to have cracks, then a crack growth rate assessment is required to ensure adequate life for the dent with crack(s) until remediation or the dent with crack(s) must be evaluated and remediated in accordance with the criteria and timing requirements in § 192.713, § 192.714, or § 192.933, as applicable.

(11) An operator using an engineering critical assessment procedure, other technologies, or techniques to comply with paragraph (c) of this section must submit advance notification to PHMSA, with the relevant procedures, in accordance with § 192.18.

(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.

(h) *Reassessments*. If an operator uses an engineering critical assessment method in accordance with paragraphs (c) and (d) of this section to determine the maximum reevaluation intervals, the operator must reassess the anomalies as follows:

(1) If the anomaly is in an HCA, the operator must reassess the anomaly within a maximum of 7 years in accordance with § 192.939(a), unless the safety factor is expected to go below what is specified in paragraph (c) or (d) of this section.

(2) If the anomaly is outside of an HCA, the operator must perform a reassessment of the anomaly within a maximum of 10 years in accordance with § 192.710(b), unless the anomaly safety factor is expected to go below what is specified in paragraphs (c) or (d) of this section.

[Amdt. 192-125, Oct. 01, 2019, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

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

§192.713

Transmission lines: Permanent field repair of imperfections and damages.

[Effective Date: 01/13/00]

(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.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]

GUIDE MATERIAL

1 GENERAL

1.1 Repair method.

There are a number of repair methods available to restore the serviceability of transmission pipelines. However, operators are cautioned that not all repair methods are suitable for permanent repair of leaking or through-wall defects. For leak repair, see §192.717. When evaluating the types of repair, the operator should consider factors such as the following.

(a) Type of defect: Corrosion, dents, gouges, stress concentrators, unacceptable wrinkle bends, cracks, crack-like defects, compound defects *(e.g.,* dents with corrosion or stress concentrators), defects in the pipe wall.
(b) Status of defect: Leaking or non-leaking.
(c) Class location or HCA area.
(d) Location of defect on the pipe such as clock position or along a seam or girth weld.
(e) Pipe properties including diameter, thickness, grade, seam type.
(f) MAOP and operating stress levels (% SMYS) of the pipeline.
(g) Remaining strengths calculations (see guide material under §192.485).
(h) Required pressure reduction or other operational issues (see 2 below).
(i) Temporary or permanent repair.
(j) Availability of repair materials.

1.2 Repair method selection.

The repair method selected should:

(a) Have or result in a restored strength at least equal to that required for the MAOP of the pipe being replaced; and
(b) Be capable of withstanding the anticipated circumferential and longitudinal stresses, including additional stress due to external loading.

1.3 Impairment beyond area of concern.

The operator should consider the possibility that some degree of impairment might have occurred beyond the area of immediate concern. (For information regarding corrosion, see guide material under §192.459). The impairment might be due to a defect in the seam weld, external or internal corrosion, or damage by outside forces or excavation. The pipe on each side of the known impairment should be examined to determine the extent of the repair.

1.4 Written procedures.

The operator should have written procedures for each type of repair and should consider developing site-specific written procedures as needed to address the specific conditions.

1.5 Other

Other items the operator should consider include the following.

(a) Trench and excavation safety (see 2.8 of the guide material under §192.605).
(b) Potential for accidental ignition (see guide material under §192.751).
(c) Blowdown and purging plans (see Guide Material Appendix G-192-12).
(d) Qualification of personnel performing repairs (see guide material under §192.805).
(e) Ability to use internal inspection devices (see §192.150).
(f) PRCI Pipeline Repair Manual (PR-218-9307).

2 REPAIR PRESSURE (§192.713(b))

2.1 General.

(a) In establishing a safe level of pressure in a pipeline that is to remain in service during repair operations, the primary consideration is the severity of the defect to be repaired. This includes consideration of both depth and geometry (*i.e.,* the amount of stress concentration, such as in sharp-bottomed gouges). Severe defects should not be repaired under pressure unless the operator has sufficient experience to make a sound evaluation of the defect. In addition, the effect of any known secondary stresses should be considered.
(b) The operator should also consider the effect of pressure reductions on firm-service requirements, service interruptions, or other operational requirements. If the operator has a control room, communication is critical during the repair process (see 3.3 and 3.4 of the guide material under §192.631).
(c) A common practice is to reduce the operating pressure to a level not exceeding 80% (for composite wrap repairs, see 7 below) of the pressure at the time the condition was discovered until the repair is completed.

2.2 Special consideration.

While welding reinforcements directly to pressurized pipe has been done successfully at higher stress levels, the following formula describes a recommended maximum pressure for this repair procedure.

$$P = \frac{2S(t - {}^{3}\!/_{32})(0.72)}{D}$$

Where:

P	=	Internal pressure, psig
S	=	Specified minimum yield strength, psi
t	=	Nominal pipe wall thickness, inches
D	=	Nominal outside diameter, inches

2.3 Manufacturer's recommendations

The operator is advised to follow manufacturer's recommendations regarding pressure reductions for repair methods such as composite wrap repairs.

3 WELDING

3.1 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).

3.2 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.

3.3 Reliable engineering tests and analyses.

See guide material under §192.485.

4 PIPE REPLACEMENT (§192.713(a)(1))

Pipe replacement by cutting out and replacing a cylinder of pipe is a repair option under §192.713 and should be considered for repair of dents, wrinkles, or other pipe changes such as expanded pipe or buckles. Replacement can use pipe that has been pre-tested to the appropriate pressure for the MAOP.

5 SPLIT SLEEVE REPAIR (§192.713(a)(2))

5.1 General.

(a) The use of an appropriately designed full-encirclement split sleeve is recognized as an acceptable repair method. Other methods are also available, such as the use of composite-reinforced wrap material addressed in 7 below. The operator is advised to follow manufacturer's instructions for installation.

(b) The operator should determine the type of sleeve to be used in the repair.

(1) Type A sleeve provides defect reinforcement. This type of split sleeve restores the strength of the pipe by containing and reinforcing the defect and reduces bulging of a defective area. The two parts of the split sleeve are installed around the pipe to provide the required reinforcement. Effectiveness of the repair is improved by using a filler material (e.g., polyester epoxy) in the defect which provides support. Type A sleeves are assembled by bolting or welding (welding to the carrier pipe might not be necessary). This type of sleeve cannot be used to repair leaks and should not be used for circumferential defects or deep defects since corrosion could occur in the annular space between the carrier pipe and sleeve.

Note: Composite wrap repairs are a type of reinforcing sleeve (see 7 below).

(2) Type B sleeve is a pressure containing sleeve. A pressure containing split sleeve provides a different function and can be used to contain a leak or to reinforce an area where a defect exists. Because the sleeve contains pressure, operators are advised to select a sleeve commensurate with the current carrier pipe MAOP. The application of the Type B sleeve requires the sleeve ends to be fillet welded to the pipe. The use of low hydrogen welding procedures, additional support of the pipe because of the additional weight, and welding inspection of the fillet welds should be considered before using this type of repair.

Note: Some Type B sleeves might also be called by other names (e.g., pumpkins, watermelons, turtles) due to the shape of the sleeves being suitable to fit around couplings.

(c) 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 1.3 above), and

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

(d) A wide variety of repair methods have 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 designed and tested to ensure its reliability for the conditions of installation.

5.2 Fillet welds.

Fillet welds on pressurized carrier piping are prone to cracking due to the extreme cooling action.

Because examination of completed welds by radiographic or ultrasonic means might not detect such cracking due to the geometry of the fillet weld. Use of the following is recommended.

(a) Low-hydrogen welding process
(b) Multi-pass welding techniques with visual examination after each pass
(c) Magnetic particle or liquid penetrant inspection if visual examination indicates further nondestructive inspection is necessary.

5.3 Design considerations for repair sleeves.

A reference for one set of sleeve designs is PRCI L22279, "Further Studies of Two Methods for Repairing Defects in Line Pipe."

For evaluating other available designs or developing new designs, consider the following factors.

(a) Sleeves should be designed for strength at least equal to the maximum allowable operating pressure of the repaired pipe.
(b) Sleeves should not be less than 4 inches in length. In determining the length of a sleeve, the operator should consider that some degree of impairment might have occurred beyond the immediate area. See 1.3 above.
(c) The use of a low-hydrogen welding procedure for longitudinal and circumferential welds. The integrity of these welds is affected by heat dissipation due to gas flow through the line and extra metal mass adjacent to the weld.
(d) Circumferential welds at the sleeve ends are required when repairing a leaking defect. However, end welds may or may not be beneficial for a non-leaking defect. If end welds are used on a non-leaking defect, consideration should be given to equalizing the pressure across the defect. One way to do this is by tapping the carrier pipe in order to connect the annular space between the carrier pipe and the sleeve to the pressure inside the carrier pipe.
(e) Sealing the ends of non-pressure containing sleeves, possibly by means other than welding, to prevent corrosion in the annular space between the carrier pipe and the sleeve.
(f) The capacity of end welds to withstand anticipated circumferential and longitudinal stresses, including external forces. Special attention should be given to stresses resulting from unusually long sleeves or sleeves subject to bending stresses.

6 GRINDING OR BUFFING

(a) Grinding or buffing is a suitable method of removing the following.
  (1) Surface dents or gouges with sharp edges or other stress concentrators. A gouge is defined as pipe material moved, but not necessarily metal removed from the pipe wall.
  (2) Other localized surface defects such as arc burns.
(b) The operator should develop a site-specific written plan for each grinding repair. The plan should include the following information.
  (1) Pipe information such as pipe grade and wall thickness.
  (2) Maximum amount of pipe wall thickness that can be removed if the grinding is the sole repair method, which is calculated using the design formula in §192.107 or remaining strength calculations.
(c) After grinding, the area should be checked with nondestructive testing such as magnetic particle or dye penetration technology to determine if there are any remaining cracks or other stress concentrations.
(d) Grinding or buffing should continue until all cracks or stress concentrators are removed or until maximum specified removal or wall thickness is reached. In no instance should more than 40% of the wall thickness be removed during a grinding or buffing repair. The grinding or buffing should leave smooth contours with no sharp edges. If maximum metal removal is reached before all cracks are removed, the operator should consider another method of repair or modify the plan to include some sort of strength reinforcement such as a composite wrap repair.
(e) In-service grinding repairs must be done by qualified personnel (see Subpart N).
(f) The final wall thickness should be recorded since pipe wall removal could affect future class location changes or integrity management repairs.

7 COMPOSITE WRAP REPAIRS

(a) A composite wrap is a type of repair designed to restore the strength to corroded or damaged pipe. Some manufacturers provide for custom repairs based on actual conditions; others use a set number of wraps for all types of damage. Review the manufacturer's installation requirements before deciding to use a composite wrap to make a permanent repair.
(b) Composite wrap repairs generally consist of a mastic or epoxy binder and a compatible wrapping material that is installed over the binder. The epoxy or mastic is used to fill in the pipe defects to support the wraps installed above. The multiple layers of wrapping material are "glued" together and to the pipe. After a specified curing time, the wrap restores strength to the pipe.
(c) The operator should review the manufacturer's guidelines to determine if the materials can be used to repair certain defects. Generally, composite wrap repairs cannot be used for repairs of leaks or cracks, or seam defects in ERW pipe. Composite wrap repairs are good for corrosion defects, dents, gouges (if stress concentrators are removed), non-ERW seam defects, and girth weld defects. They may also be used to reinforce grinding repairs where too much pipe wall has been removed.
(d) Multiple wraps can be placed end to end for longer repairs.
(e) Manufacturer's instructions for the composite wrap are to be followed when:
  (1) Installing composite wrap repairs.
  (2) Extending the repair beyond each end of the defect.
  (3) Training personnel to perform the repairs.
  (4) Reducing pressure during the repair and curing time (many require a significant pressure reduction up to approximately 50%).
(f) Because composite wrap repairs are not metallic, an operator should consider the use of a magnetic marker such as a steel band or small steel coupon on or near the repair to indicate on MFL ILI tools that a repair has been made.

8 HOT TAPS

A hot tapping operation is an in-service repair option that may be used to remove small in-wall defects found in steel pipe. In general, fittings that are normally used for tapping are welded onto the pipeline and tapped, removing the pipe defect in the tap coupon. The hot tap fitting reinforces the tapped hole in the pipeline. Items to consider include the following.
(a) The location of the defect should be in a place that makes using a hot tap fitting practical and in accordance with the fitting manufacturer's installation recommendations (*e.g.,* the fitting should be horizontal or vertical, the installation machine should be accessible and operable).
(b) The removed pipe coupon should completely remove the defect.
(c) The location should not invite potential damage to the hot tap fitting at a future time.
(d) The availability of properly-sized hot tap fittings in the needed time frame for the repair.
(e) Less costly repair options might be available.

9 DIRECT DEPOSITION WELDING

(a) Direct deposition welding may be used for repair of non-leaking defects caused by corrosion (internal or external) and to smooth ground-out areas without a dent. Additional metal is deposited in the anomaly using welding techniques. In the case of internal corrosion, the wall build-up is on the exterior of the pipe. Legacy long seams should not be repaired with direct deposition welding. Integrity concerns for direct deposition welding repairs include the following.
  (1) Risk of burn-through during the repair.
  (2) Possible cracks or other defects in the deposited weld material.
  (3) Fatigue cracks or hydrogen embrittlement cracking.
  (4) Insufficient repair strength due to an inadequate deposition of material.
(b) The operator must develop a welding procedure specific for the repair (see §192.225) and should consider the following.

(1) Visible signs of corrosion should be removed using a wire brush or by sanding.
(2) Low hydrogen electrodes should be used for all passes of the weld deposition.
(3) The number of passes needed to attain the required metal deposition should be defined.
(4) The deposited weld material should completely fill the corrosion pit or defect to ensure pipe wall integrity.
(5) The repair should be ground flush for inspection purposes and should be non-destructively tested to ensure the integrity of the repair.

10 RECORD KEEPING

Records showing the date, location, and description of the repair must be retained for the life of the pipeline (§192.709(a)). The description of the repair and related information should include the following.

(a) Data which supports the MAOP of the line such as materials and testing information, including pressure charts.
(b) Personnel qualification.
(c) Site-specific procedures (as for grinding or direct deposition welding),
(d) Other information as determined by the operator.

192.714

Transmission lines: Repair criteria for onshore transmission pipelines.

[Effective Date:05/24/23]

(a) *Applicability*. This section applies to onshore transmission pipelines not subject to the repair criteria in subpart O of this part, and which do not operate under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620. Pipeline segments that are located in high consequence areas, as defined in § 192.903, must comply with the applicable actions specified by the integrity management requirements in subpart O. Pipeline segments operating under an alternative MAOP in accordance with §§ 192.112, 192.328, and 192.620 must comply with § 192.620(d)(11).

(b) *General*. Each operator must, in repairing its pipeline systems, ensure that the repairs are made in a safe manner and are made to prevent damage to persons, property, and the environment. A pipeline segment's operating pressure must be less than the predicted failure pressure determined in accordance with § 192.712 during repair operations. Repairs performed in accordance with this section must use pipe and material properties that are documented in traceable, verifiable, and complete records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, an operator must obtain the undocumented data through § 192.607.

(c) *Schedule for evaluation and remediation*. An operator must remediate conditions according to a schedule that prioritizes the conditions for evaluation and remediation. Unless paragraph (d) of this section provides a special requirement for remediating certain conditions, an operator must calculate the predicted failure pressure of anomalies or defects and follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must document the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety. Each condition that meets any of the repair criteria in paragraph (d) of this section in an onshore steel transmission pipeline must be—

(1) Removed by cutting out and replacing a cylindrical piece of pipe that will permanently restore the pipeline's MAOP based on the use of § 192.105 and the design factors for the class location in which it is located; or

(2) Repaired by a method, shown by technically proven engineering tests and analyses, that will permanently restore the pipeline's MAOP based upon the determined predicted failure

pressure times the design factor for the class location in which it is located.

(d) *Remediation of certain conditions.* For onshore transmission pipelines not located in high consequence areas, an operator must remediate a listed condition according to the following criteria:

(1) *Immediate repair conditions.* An operator must repair the following conditions immediately upon discovery:

(i) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with § 192.712(b), of less than or equal to 1.1 times the MAOP.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or has a longitudinal joint factor less than 1.0, and the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

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

(2) *Two-year conditions*. An operator must repair the following conditions within 2 years of discovery:

(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 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent of the pipeline 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 or helical (spiral) seam weld, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(iv) For metal loss anomalies, a calculation of the remaining strength of the pipe shows a predicted failure pressure, determined in accordance with § 192.712(b) at the location of the anomaly, of less than 1.39 times the MAOP for Class 2 locations, or less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4, as specified in paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, is in an area with widespread circumferential corrosion, or could affect a girth weld, and that has a predicted failure pressure, determined in accordance with § 192.712(b), less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric

flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions*. An operator must record and monitor the following conditions during subsequent risk assessments and integrity assessments for any change that may require remediation.

(i) A dent that is located between the 4 o'clock and 8 o'clock positions (bottom 1/3 of the pipe) with a depth greater than 6 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12).

(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 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12), and where an engineering analysis performed in accordance with § 192.712(c) determines that critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal or helical (spiral) seam weld, and where an engineering analysis of the dent and girth or seam weld, performed in accordance with § 192.712(c), demonstrates critical strain levels are not exceeded. These analyses must consider weld mechanical properties.

(iv) A dent that has metal loss, cracking, or a stress riser, and where an engineering analysis performed in accordance with § 192.712(c) demonstrates critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or that has a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or is greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *Temporary pressure reduction*. (1) Immediately upon discovery and until an operator remediates the condition specified in paragraph (d)(1) of this section, or upon a determination by an operator that it is unable to respond within the time limits for the conditions specified in paragraph (d)(2) of this section, the operator must reduce the operating pressure of the affected pipeline to any one of the following based on safety considerations for the public and operating personnel:

(i) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered,

(ii) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located; or

(iii) A level not exceeding the predicted failure pressure divided by 1.1.

(2) An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. Notification to PHMSA does not alleviate an operator from the evaluation, remediation, or pressure reduction requirements in this section.

(3) When a pressure reduction, in accordance with paragraph (e) of this section, exceeds

365 days, an operator must notify PHMSA in accordance with § 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.

(4) An operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure and the implementation of the actual reduced operating pressure for a period of 5 years after the pipeline has been repaired.

(f) *Other conditions*. Unless another timeframe is specified in paragraph (d) of this section, an operator must take appropriate remedial action to correct any condition that could adversely affect the safe operation of a pipeline system in accordance with the criteria, schedules, and methods defined in the operator's operating and maintenance procedures.

(g) *In situ direct examination of crack defects*. Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

(h) Determining predicted failure pressures and critical strain levels. An operator must perform all determinations of predicted failure pressures and critical strain levels required by this section in accordance with § 192.712.

[Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

§192.715

Transmission lines: Permanent field repair of welds.

[Effective Date: 07/13/98]

Each weld that is unacceptable under §192.241(c) must be repaired as follows:

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

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

(1) The weld is not leaking;

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

(3) Grinding of the defective area can be limited so that at least 1/8 inch (3.2 millimeters) thickness in the pipe weld remains.

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

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

GUIDE MATERIAL

See guide material under §192.713.

§192.717

Transmission lines: Permanent field repair of leaks.

[Effective Date: 01/13/00]

Each permanent field repair of a leak on a transmission line must be made by —

(a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or

(b) Repairing the leak by one of the following methods:

(1) Install a full encirclement welded split sleeve of appropriate design, unless the

(b) Where necessary, consider marking or labeling the equipment requiring special attention such as regulator bypass valves, relief device isolation valves, and valves associated with control, sensing, and supply lines. See guide material under §192.203.
(c) When it is necessary to continue gas flow through a manually controlled bypass to inspect or test station components, the manual valve should be operated by personnel who are qualified (see Subpart N) to control the pressure in the downstream system at or below its MAOP. The pressures should be continuously monitored and the valve adjusted to prevent an overpressure condition. The manual bypass valve should be clearly marked showing the direction it is to be turned to either open or close the valve.
(d) Gas systems that experience an interruption in electric service due to rolling electric blackouts or unplanned electric system outages might be negatively affected by an abrupt turn-on or turn-off of the electricity. Operators might experience pressure drops, pressure loss in entire gas systems, or pressure relief devices releasing gas to atmosphere. Operators should consider monitoring critical pressure regulating stations during known blackout periods and conducting additional inspections after the electric system outages.

2 VISUAL INSPECTIONS

Visual inspections should be made to determine that a satisfactory condition exists which will allow proper operation of the equipment. The following should be included in the inspection, where necessary.
(a) Station piping supports, pits, and vaults for general condition and indications of ground settlement. Prior to entering a vault that has restricted openings (e.g., manholes) or which is more than four feet deep, and while working therein, tests should be made of the atmosphere in the vault. See guide material under §192.749 for atmospheric test procedures.
(b) Station doors and gates, and pit and vault covers to ensure that they are functioning properly and that access is adequate and free from obstructions.
(c) Ventilating equipment installed in station buildings or vaults for proper operation and for evidence of accumulation of water, ice, snow, or other obstructions.
(d) Control, sensing, and supply lines for conditions that could result in a failure.
(e) All locking devices for proper operation.
(f) Posted station schematics for correctness.

3 STOP VALVES

An inspection or test of stop valves should be made to ensure that the valves will operate and are correctly positioned. Caution should be used to avoid any undesirable effect on pressures during operational checks. The following should be included in the inspection or test.
(a) Station inlet, outlet and bypass valves.
(b) Relief device isolating valves.
(c) Control, sensing, and supply line valves.

4 PRESSURE REGULATORS

4.1 General operating conditions.
Consideration should be given to taking the station out of service during inspection and testing activities. Each pressure regulator used for pressure reduction or for pressure limiting should be inspected or tested. The procedure should ensure that each regulator is in good working order, controls at its set pressure, operates or strokes smoothly, and shuts off within the expected and accepted limits. If acceptable operation is not obtained during the operational check, the cause of the malfunction should be determined and the appropriate components should be adjusted, repaired, or replaced as required. After repair, the regulator should be checked for proper operation.

4.2 Special conditions.
(a) Regulator bodies that are subjected to erosive service conditions may require visual internal

inspection.

(b) More frequent inspections or additional inspections may be required as a result of construction and hydrostatic testing upstream.

(c) More frequent inspections or additional inspections may be required as a result of abnormal changes in operating conditions or unusual flows or velocities.

(d) Whenever abnormal pressures are imposed on pressure or flow devices, the event should be investigated and a determination made as to the need for inspection and repairs.

(e) Inspection and testing should be performed during times of low station throughput or when the station can be taken out of service, if practical.

5 RELIEF DEVICES

(a) The inspection or test should ensure the following.
  (1) Correct set pressure of relief devices. See 5(b) below for testing for correct set pressure.
  (2) Correct liquid level of liquid seals.
  (3) That the stacks are free of obstructions.

(b) One of the methods listed below may be used to test for correct set pressure. Test connections should include a gauge or deadweight tester so arranged that the pressure at which the device becomes operative may be observed and recorded.
  (1) The pressure may be increased in the segment until the device is activated. During the tests, care should be exercised to ensure that the pressure in the segment protected by the relief device does not exceed the limit in §192.201.
  (2) The pressure from a secondary pressure source may be added to the pilot or control line until the device is activated.
  (3) The device may be transported to a shop for testing and returned to service. When the device is to be shop-tested or otherwise rendered inoperative, adequate overpressure protection of the affected segments should be maintained during the period of time the relief device is inoperative.

(c) See §192.743 for reviewing and calculating, or testing, the required capacity of relief devices.

6 FINAL INSPECTION

The final inspection procedure should include the following.

(a) A check by personnel who are qualified (see Subpart N) for proper position of all valves. Special attention should be given to regulator station bypass valves, relief device isolating valves, and valves in control, sensing, and supply lines.

(b) Restoration of all locking and security devices to proper position.

§192.740

Pressure regulating, limiting and overpressure protection – Individual service lines directly connected to production, gathering, or transmission pipelines.

[Effective Date: 03/12/21]

(a) This section applies, except as provided in paragraph (c) of this section, to any service line directly connected to a transmission pipeline or regulated gathering pipeline as determined in § 192.8 that is not operated as part of a distribution system.

(b) Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every 3 calendar years, not exceeding 39 months, to determine that it is:

(1) In good mechanical condition;

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

(3) Set to control or relieve at the correct pressure consistent with the pressure limits of § 192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and

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

(c) This section does not apply to equipment installed on: (1) A service line that only serves engines that power irrigation pumps; (2) A service line included in a distribution integrity management plan meeting the requirements of subpart P of this part; or (3) A service line directly connected to either a production or gathering pipeline other than a regulated gathering line as determined in § 192.8 of this part.

[Amdt. 192-123, 82 FR 7998, Jan. 23, 2017]

GUIDE MATERIAL

No guide material available at present.

§192.741

Pressure limiting and regulating stations: Telemetering or recording gages.

[Effective Date: 11/12/70]

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

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

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

GUIDE MATERIAL

1 MAINTENANCE OF TELEMETERING INSTRUMENTS, RECORDING GAUGES, AND RECORDS

1.1 Operation, testing, and maintenance of instruments.

All instruments used for telemetering or recording pressures should be operated in accordance with the manufacturers' recommended instructions, and should be inspected and tested in accordance with said instructions at intervals not exceeding 1 year.

1.2 Review of recording charts.

Each operator should review the recorded pressure readings either at the time of inspection or shortly after the removal of the gauge chart from the gauge. Each operator should review the recorded pressure readings for the following.

(a) Any indication of abnormal operating condition (i.e., high- or low-pressure).
(b) Proper operation by the recording instrument.
(c) Proper operation of pressure regulating devices.

1.3 Identification of pressure charts.

The operator should indicate on each pressure recording chart the following information.

(a) Name of the operator.
(b) Location of recording gauge-station name or number or both.
(c) Date and time of recorded pressure readings.

(d) Any tests performed on the gauge during the recorded period.

1.4 Retention of pressure records.

All records showing the recorded pressure readings should be retained in accordance with requirements of the governmental agency that has jurisdiction over the operator, unless the operator requires their retention for a longer time period.

2 DISTRIBUTION SYSTEMS SUPPLIED BY MORE THAN ONE PRESSURE REGULATOR STATION (§192.741(a))

2.1 Telemetering or recording pressure gauge.

Each operator should install and maintain telemetering or recording pressure gauges at some points in the system. The location of the gauges is dependent upon the design of the system, and therefore, should be at points that would best indicate an abnormal operating condition.

2.2 Temporary recording gauges at low-pressure points.

Each operator should give consideration to installing temporary recording gauges at various locations in the distribution system at suspected or anticipated low-pressure points. The data compiled or derived from these gauges will assist the operator in determining the adequacy of the system design. These gauges should remain until the suspected condition is:

(a) Shown to be satisfactory; or
(b) Corrected.

2.3 Additional telemetering or recording pressure gauges.

If the system is such that installed gauges cannot adequately indicate the pressure in the distribution system, the operator should give consideration to installing additional telemetering or recording pressure gauges at selected points to assist in maintaining the maximum and minimum allowable operating pressures as required by §§192.619, 192.621, and 192.623.

3 DISTRIBUTION SYSTEMS SUPPLIED BY ONE PRESSURE REGULATOR STATION (§192.741(b))

3.1 Telemetering as early warning agent.

Telemetering of pressure or flow may be used as an early warning agent to disclose system failures or malfunctions. The following parameters should be considered to determine if a telemetering system is feasible and practical.

(a) Response time of operating personnel to the source of the telemetered signal.
(b) The magnitude of pressure drop or flow increase which would indicate a system failure.
(c) Design limits of the telemetering system to properly respond to the criteria established in (b) above.
(d) Recognition of possible failures to which the telemetry would not respond.
(e) Seasonal changes in normal pressure or flow requirements, which may require resetting the alarm limits.
(f) The complexity of the telemetry system to be installed. The system could vary from a simple high-low pressure switch alarm to a more sophisticated system transmitting signals to a computer.
(g) Location of the telemetered alarm at a center manned 24 hours a day having the capability to alert appropriate operating personnel.

On the basis of the foregoing factors, determine whether (1) the telemeter is feasible, and if so, (2) determine whether it is practical in relation to cost, probability of pipeline failure, proximity to the operating headquarters, risk analysis, and system safety.

3.2 Monitoring of single feed distribution system operations.

Even though the number of source points required to monitor a single feed distribution system may be fewer than the number required for a distribution system fed by more than one pressure regulator station, the guide material in 2.1, 2.2, and 2.3 above should be considered.

3.3 Procedures for vaults with restricted openings.
Safety measures should be considered for vaults that have restricted openings and are greater than 4 feet deep. OSHA regulations could be a source of safety information.

4 INSPECTION AND REPAIRS

(a) If gas is detected prior to entry or while working in the vault, or if the operator can hear or smell gas, the operator should follow the appropriate guide material in 3 above.
(b) In accordance with the operator's applicable O&M and safety procedures, the operator should enter or remain in the vault:
 (1) To further investigate, classify, and repair the leak as necessary
 (2) To inspect equipment in the vault including the ventilating equipment and ensure it is adequately operating as intended.
(c) Whenever personnel enter a vault, periodic or continuous monitoring should be performed in vaults where the oxygen levels could be depleted (see 3 above).

5 VAULT COVER INSPECTION (§192.749(d))

Consider the following during the vault cover inspection.
(a) Vault cover lacks a locking device or other tamper-proof measures to prevent unauthorized access.
(b) Vault cover is damaged or deteriorated to the point it is unsafe to open.
(c) Vault cover is damaged or deteriorated to the point it is unsafe to support expected external loads.
(d) Vault cover is not identified as housing gas facilities, as might be required by the operator or local regulatory authority.
(e) Any other hazardous condition that might be detrimental to public safety as deemed by the operator.

§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.

[Amdt. 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

(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

A reference is AGA XR603, "Plastic Pipe Manual for Gas Service," Chapter VI – Maintenance, Operation and Emergency Control Procedures.

§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.

[Amdt. 192-25, 41 FR 23679, June 11, 1976; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

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

See guide material under §192.614, and Guide Material Appendices G-192-16 and G-192-18.

§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.

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

1 GENERAL

(a) To comply with this regulation, operators should develop a maintenance and calibration plan using information from equipment manufacturers or from the operator's testing and experience, or both. The plan should address equipment that is used in heat-fusion joining of plastic pipe regardless of whether the equipment is owned, rented, or part of a contractor's fleet.

(b) For guidance related to equipment inspections, see 3.2 of the guide material under §192.281.

2 IDENTIFICATION OF EQUIPMENT AND MANUFACTURER RECOMMENDATIONS

(a) Identify the equipment used to complete the fusion process.

(1) Butt fusion, saddle fusion, socket fusion, electrofusion equipment.

(2) Facers used to prepare the pipe for joining.

(3) Heaters.

(4) Power sources, electrofusion only.

(b) Gather available information.
  (1) Equipment manuals.
  (2) Manufacturer information related to recommended maintenance and schedule intervals for maintenance of each type of equipment.
  (3) Manufacturer information related to recommended calibration activities.

3 MAINTENANCE AND CALIBRATION PLAN CONTENTS

(a) General plan contents.
  (1) A listing of the equipment covered by the plan.
  (2) Manufacturer maintenance recommendations and schedule intervals for each type of equipment.
  (3) Manufacturer calibration recommendations and schedule intervals for each type of equipment.
  (4) If the operator chooses to develop procedures for maintenance and calibration activities (as allowed in §192.756), include the following.
    (i) Testing and experience information documenting that the procedures produce acceptable joints.
    (ii) If a manufacturer recommends a more frequent interval than the procedure developed, document the testing and experience that supports the longer interval between maintenance and calibration activities.
(b) Special considerations – rented or contractor-owned equipment.
  (1) Detail how rented equipment and contractor-owned equipment will be uniquely identified within the operator's equipment record system, such as the following.
    (i) Serial numbers.
    (ii) Equipment asset numbers.
    (iii) State registration information.
  (2) Define an inspection procedure for each type of equipment.
    (i) The operator might choose to specify an "as received" inspection as well as an "as returned" inspection for rental equipment.
    (ii) The operator might choose to specify an inspection protocol for contractor-owned equipment.
  (3) Identify the maintenance and calibration records to be provided by the rental company or contractor prior to use for each type of equipment
    (i) Consider requiring the Date of Last Maintenance or Date of Last Calibration for each piece of equipment used in the joining process as part of project documentation.
    (ii) Consider whether the rental company or contractor uses the equipment manufacturer's maintenance and calibration recommendations or has developed its own.
  (4) If the rental company or contractor uses its own procedures, consider requesting validation documentation.
    (i) Consider reviewing the rental company's maintenance and calibration plan prior to renting the equipment.
    (ii) Consider including a review of maintenance and calibration programs in the contractor qualification process.
  (5) Maintain a copy of the maintenance and calibration documentation related to the rented and contractor-owned equipment used on regulated pipeline projects in accordance with the operator's record retention policy.
(c) Implementation Procedures.
  (1) Procedures by which the operator will ensure manufacturer recommendations (or internally developed procedures) are met in a timely manner.
  (2) Procedures to address maintenance and calibration needs identified through field inspections. For instance, tagging equipment for maintenance to be performed before returning to use.

(3) Detail how equipment's maintenance and calibration status will be shared with regulatory agency if requested.
   (i) A sticker or tag on the equipment can provide a visual confirmation of maintenance or calibration status.
   (ii) A web portal or electronic inspection records might also be accessible in the field.

(4) Describe the record retention policy for the maintenance and calibration program. Consider maintaining records for two cycles of maintenance and calibration.

4 RECOMMENDED RECORDS TO BE MAINTAINED

(a) The maintenance and calibration plan.
(b) For operator-owned equipment.
   (1) Listing of each piece of equipment to be maintained and/or calibrated. This might require creating an inventory of assets and providing each item with a unique equipment identifier. Equipment to consider is listed in 1 above.
   (2) Records of Preventive Maintenance inspections of equipment
      (i) This does not include daily inspection records of equipment.
      (ii) Inspections are recommended at least annually.
   (3) Records of maintenance.
      (i) Equipment identifier.
      (ii) Date and time.
      (iii) Person conducting the maintenance activity.
      (iv) What adjustments and/or replacements were performed.
   (4) Records of calibrations.
      (i) Equipment identifier.
      (ii) Date and time.
      (iii) Person conducting the calibration.
      (iv) What adjustments and/or replacements were performed.
(c) For rented equipment and contractor owned equipment.
   (1) Equipment identifier.
   (2) Documentation that rented equipment has been maintained and calibrated in accordance with the applicable maintenance and calibration plan.
   (3) Records of equipment's most recent preventive maintenance inspection.
   (4) Records of any inspections completed in accordance with the operator's maintenance and calibration plan.
   (5) Records of any maintenance performed on the equipment during the rental period or project. Maintain the same information as listed above for operator-owned equipment.
   (6) Records of any calibrations performed on the equipment during the rental period or project. Maintain the same information as listed above for operator-owned equipment.

§192.761

(Removed.)

[Effective Date: 02/14/04]

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: 05/24/23]

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 required by § 192.13(d).

(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.

(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to —

(1) 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.

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

(p) A process for identification and assessment of newly-identified high consequence areas. (See §§192.905 and 192.921.)

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004 and Amdt. 192-95 Correction & Petition for Reconsideration, 69 FR 18228, Apr. 6, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006, Amdt. 192-132, 87 FR 52224, Aug. 24, 2022]

GUIDE MATERIAL

***Note**:* References to ASME throughout this section of guide material are specific to the edition of ASME B31.8S as incorporated by reference (IBR) in §192.7. Abbreviated references are used in guide material below. Example: "ASME 12.2(a)(2)" means ASME B31.8S, Paragraph 12.2(a)(2) of the IBR edition. See 3.2 of the guide material under §192.907.

1 GENERAL

The Integrity Management Program (IMP) consists of program elements encompassing the plans, processes, and procedures required for integrity management. The IMP will vary from one operator to the next, but must at least address the 16 program elements as specified in this regulation. The operator is further required to include other program elements as necessary to effectively manage pipeline integrity within the operator's management system. In addition, the program is required to document how the processes and associated procedures will be managed and implemented.

2 FRAMEWORK

In the early stages, the IMP may not be fully developed. If the program is not fully developed, the framework describes the process for developing a complete program. The framework should identify who is responsible for individual process development and provide a timeline for the completion of the program elements. It is required that program elements be fully developed before implementation.

3 MANAGEMENT OF CHANGE (MOC) (§192.911(k))

There are two sections of Part 192 Subpart O that require operators to manage changes. First, §192.909 requires operators to document changes to the written IMP. Second, §192.911(k) requires operators to develop a written MOC process to track changes to the integrity of the pipeline. Operators may combine these requirements into a single MOC process or use separate processes. For guidance regarding IMP changes, including PHMSA-OPS notification, see guide material under §192.909.

An operator may be able to manage changes that impact the integrity of the pipeline through current practices as long as the operator can demonstrate that current practices meet the requirements of ASME 11. Examples of current practices that manage change include the following.

(a) Budgeting and mapping processes that record physical pipeline changes.
(b) Work management systems that document permit requirements and acquisitions.
(c) O&M procedures or IMP manual revision logs that track written procedure changes.
(d) Organizational charts and job descriptions that establish individual responsibilities.
(e) Maps, aerial photos, or logs that document the annual HCA review.

The following guide material is based on the requirements of ASME 11.

3.1 Objective.

ASME 11(a) requires that MOC procedures be developed to identify and consider the impact of changes

assessment.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004]

GUIDE MATERIAL

1 SUPERVISORY PERSONNEL QUALIFICATIONS

1.1 General.

The Integrity Management Program (IMP) should define the training, qualification, or experience required for supervisory personnel whose responsibilities relate to the IMP. Supervisory personnel can acquire thorough knowledge of the IMP by achieving the following.

(a) General understanding of, and familiarity with, the overall program; and
(b) Specific knowledge in their respective areas of responsibility.

1.2 Gaining general understanding.

Examples of means used to gain general understanding of the IMP include the following.

(a) Conducting periodic review of the written program.
(b) Training or orientation sessions.
(c) Conducting peer reviews.
(d) Using a list of subject matter experts that can be contacted for additional details.

1.3 Demonstrating specific knowledge.

Examples of means used to demonstrate specific knowledge of an individual's area of responsibility include the following.

(a) Internal and external training records.
(b) Experience résumés.
(c) Licenses or certifications.
(d) Continuing educational credits.
(e) Qualification records.
(f) Authored papers or articles that have been published.
(g) Documented experience in developing standards and procedures.
(h) Copies of presentations given to public, industry, or an operator's internal groups.
(i) Regulatory testimony.

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: 05/24/23]

(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 threat categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Stable threats, such as manufacturing, welding, 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, such as operational or maintenance mishaps, or design and construction mistakes.

(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 data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. Operators must begin to integrate all pertinent data elements specified in this section starting on May 24, 2023, with all available attributes integrated by February 26, 2024. An operator may request an extension of up to 1 year by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (b), the reason for the requested extension, current safety or mitigation status of the pipeline segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety. An operator must gather and evaluate the set of data listed in paragraph (b)(1) of this section. The evaluation must analyze both the covered segment and similar non-covered segments, and it must:

(1) Integrate pertinent information about pipeline attributes to ensure safe operation and

pipeline integrity, including information derived from operations and maintenance activities required under this part, and other relevant information, including, but not limited to:

(i) Pipe diameter, wall thickness, seam type, and joint factor;

(ii) Manufacturer and manufacturing date, including manufacturing data and records;

(iii) Material properties including, but not limited to, grade, specified minimum yield strength (SMYS), and ultimate tensile strength;

(iv) Equipment properties;

(v) Year of installation;

(vi) Bending method;

(vii) Joining method, including process and inspection results;

(viii) Depth of cover;

(ix) Crossings, casings (including if shorted), and locations of foreign line crossings and nearby high voltage power lines;

(x) Hydrostatic or other pressure test history, including test pressures and test leaks or failures, failure causes, and repairs;

(xi) Pipe coating methods (both manufactured and field applied), including the method or process used to apply girth weld coating, inspection reports, and coating repairs;

(xii) Soil, backfill;

(xiii) Construction inspection reports, including but not limited to:

(A) Post backfill coating surveys; and

(B) Coating inspection ("jeeping" or "holiday inspection") reports;

(xiv) Cathodic protection installed, including, but not limited to, type and location;

(xv) Coating type;

(xvi) Gas quality;

(xvii) Flow rate;

(xviii) Normal maximum and minimum operating pressures, including maximum allowable operating pressure (MAOP);

(xix) Class location;

(xx) Leak and failure history, including any in-service ruptures or leaks from incident reports, abnormal operations, safety-related conditions (both reported and unreported) and failure investigations required by § 192.617, and their identified causes and consequences;

(xxi) Coating condition;

(xxii) Cathodic protection (CP) system performance;

(xxiii) Pipe wall temperature;

(xxiv) Pipe operational and maintenance inspection reports, including, but not limited to:

(A) Data gathered through integrity assessments required under this part, including, but not limited to, in-line inspections, pressure tests, direct assessments, guided wave ultrasonic testing, or other methods;

(B) Close interval survey (CIS) and electrical survey results;

(C) CP rectifier readings;

(D) CP test point survey readings and locations;

(E) Alternating current, direct current, and foreign structure interference surveys;

(F) Pipe coating surveys, including surveys to detect coating damage, disbonded coatings, or other conditions that compromise the effectiveness of corrosion protection, including, but not limited to, direct current voltage gradient or alternating current voltage gradient inspections;

(G) Results of examinations of exposed portions of buried pipelines (e.g., pipe and pipe coating condition, see § 192.459), including the results of any non-destructive examinations of the pipe, seam, or girth weld (i.e. bell hole inspections);

(H) Stress corrosion cracking excavations and findings;

(I) Selective seam weld corrosion excavations and findings;

(J) Any indication of seam cracking; and

(K) Gas stream sampling and internal corrosion monitoring results, including cleaning pig sampling results;

(xxv) External and internal corrosion monitoring;

(xxvi) Operating pressure history and pressure fluctuations, including an analysis of effects of pressure cycling and instances of exceeding MAOP by any amount;

(xxvii) Performance of regulators, relief valves, pressure control devices, or any other device to control or limit operating pressure to less than MAOP;

(xxviii) Encroachments;

(xxix) Repairs;

(xxx) Vandalism;

(xxxi) External forces;

(xxxii) Audits and reviews;

(xxxiii) Industry experience for incident, leak, and failure history;

(xxxiv) Aerial photography; and

(xxxv) Exposure to natural forces in the area of the pipeline, including seismicity, geology, and soil stability of the area.

(2) Use validated information and data as inputs, to the maximum extent practicable. If input is obtained from subject matter experts (SME), an operator must employ adequate control measures to ensure consistency and accuracy of information. Control measures may include training of SMEs or the use of outside technical experts (independent expert reviews) to assess the quality of processes and the judgment of SMEs. An operator must document the names and qualifications of the individuals who approve SME inputs used in the current risk assessment.

(3) Identify and analyze spatial relationships among anomalous information (e.g., corrosion coincident with foreign line crossings or evidence of pipeline damage where overhead imaging shows evidence of encroachment);

(4) Analyze the data for interrelationships among pipeline integrity threats, including combinations of applicable risk factors that increase the likelihood of incidents or increase the potential consequences of incidents.

(c) *Risk assessment*. An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and that analyzes the identified threats and potential consequences of an incident for each covered segment. An operator must ensure the validity of the methods used to conduct the risk assessment considering the incident, leak, and failure history of the pipeline segments and other historical information. Such a validation must ensure the risk assessment methods produce a risk characterization that is consistent with the operator's and industry experience, including evaluations of the cause of past incidents, as determined by root cause analysis or other equivalent means, and include sensitivity analysis of the factors used to characterize both the likelihood of loss of pipeline integrity and consequences of the postulated loss of pipeline integrity. An operator must use the risk assessment to determine additional preventive and mitigative measures needed for each covered segment in accordance with § 192.935 and periodically evaluate the integrity of each covered pipeline segment in accordance with § 192.937. Beginning February 26, 2024, the risk assessment must:

(1) Analyze how a potential failure could affect high consequence areas;

(2) Analyze the likelihood of failure due to each individual threat and each unique combination of threats that interact or simultaneously contribute to risk at a common location;

(3) Account for, and compensate for, uncertainties in the model and the data used in the risk assessment; and

(4) Evaluate the potential risk reduction associated with candidate risk reduction activities, such as preventive and mitigative measures, and reduced anomaly remediation and assessment intervals.

(5) In conjunction with § 192.917(b), an operator may request an extension of up to 1 year for the requirements of this paragraph by submitting a notification to PHMSA at least 90 days before February 26, 2024, in accordance with § 192.18. The notification must include a reasonable and technically justified basis, an up-to-date plan for completing all actions required by this paragraph (c)(5), the reason for the requested extension, current safety or mitigation status of the pipeline

segment, the proposed completion date, and any needed temporary safety measures to mitigate the impact on safety.

(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, such as poor joint fusion practices, pipe with poor slow crack growth (SCG) resistance, brittle pipe, circumferential cracking, hydrocarbon softening of the pipe, internal and external loads, longitudinal or lateral loads, proximity to elevated heat sources, and point loading.

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

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

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

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

(5) *Corrosion*. If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §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.

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GUIDE MATERIAL

(d) Conducting DA.
   (1) For guidance on conducting ECDA, see guide material under §§192.919 and 192.925.
   (2) For guidance on conducting ICDA, see guide material under §§192.919 and 192.927.
   (3) For guidance on conducting SCCDA, see guide material under §§192.919 and 192.929.

1.4 Other technology.

(a) Examples include the following.
   (1) Running an ILI tool that does not meet the requirements of ASME B31.8S, Paragraph 6.2.5(c).
   (2) Using Guided Wave Ultrasound as a stand-alone assessment method.
   (3) Using Guided Electromagnetic Wave as a stand-alone assessment method.
(b) For guidance on other technology, see guide material under §192.919 and the notification requirements in guide material under §192.949.

2 PRIORITIZING SEGMENTS

In general, the higher risk segments should be assessed before the lower risk segments. Based on scheduling issues and assessment methods, some lower risk segments may be assessed before higher risk segments. For example, a single ILI assessment used to assess a higher risk segment may also include one or more lower risk segments. For information on risk analysis, see guide material under §192.917.

3 ASSESSMENT FOR PARTICULAR THREATS

See guide material under §§192.917 and 192.919 on addressing particular threats.

4 PRIOR ASSESSMENT

See guide material under §191.919 for baseline assessments, and guide material under §§192.937 and 192.939 for reassessments.

5 NEWLY IDENTIFIED HCAs

See 4 of the guide material under §192.905 for guidance on newly identified HCAs.

6 NEWLY INSTALLED PIPE

The post-installation pressure test may serve as the baseline assessment. 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.

7 PLASTIC TRANSMISSION PIPELINES

See guide material under §192.917 for threats to plastic pipe. Pressure testing and other assessment methods are applicable methods for plastic pipe. Possible alternative assessment methods include the following.

(a) Inserting a camera to look for cracks or other internal defects.
(b) Performing visual inspection of a sample of suspect fittings or fusions.
(c) Performing leak surveys at an increased frequency.
(d) Shut-in test (leak test at operating pressure).

§192.923

How is direct assessment used and for what threats?

[Effective Date: 08/06/15]

(a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (EC), internal corrosion (IC), and stress corrosion cracking (SCC).

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

(1) Section 192.925 and ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) section 6.4, and NACE SP0502 (incorporated by reference, *see* §192.7), if addressing external corrosion (EC).

(2) Section 192.927 and NACE SP0206 (incorporated by reference, *see* §192.7), if addressing internal corrosion (IC).

(3) Section 192.929 and NACE SP0204 (incorporated by reference, *see* §192.7), if addressing stress corrosion cracking (SCC).

(c) *Supplemental method*. An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.

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GUIDE MATERIAL

1 GENERAL

(a) Direct Assessment (DA) is a structured process for assessing buried, onshore steel pipelines. This process is comprised of multiple, interdependent steps, which include the following.
    (1) Gathering and integration of data.
    (2) Indirect inspection.
    (3) Direct examination.
    (4) Post-assessment evaluation.
(b) See guide material under §§192.925, 192.927, and 192.929.

2 DIRECT ASSESSMENT PLAN

(a) Only operators that use DA need to prepare a written DA plan.
(b) An operator's DA plan should include a written statement, procedure, or other document addressing each specific step of the DA methodology. The plan can be multiple binders with relevant plan sections kept at appropriate locations. Other documents (or applicable sections) may be referenced. The referenced documents should be readily available to the users.
(c) DA plans will vary in length and complexity depending upon an operator's size, locale, policies, and amount of pipeline to be assessed. An operator may choose to have a single DA plan for all, or a separate DA plan for each, of the three corrosion threats: external, internal, and stress corrosion cracking.

(b) Prior to disturbing the pipeline (e.g., removing coating or disturbing pipe surface). The following are examples of data to collect and related activities that may be performed at each excavation.
  (1) Pipe-to-soil potentials with IR drop considered (e.g., ground level surface and at the pipe surface to determine cathodic protection level).
  (2) Soil-resistivity (e.g., nature of corrosion environment).
  (3) Soil sample (e.g., soil type, bacteria, moisture content, pH).
  (4) Groundwater sample (e.g., pH, bacteria, chlorides, corrosion by-products).
  (5) Under-film liquid pH (e.g., liquid present beneath the damaged coating).
  (6) Coating type.
  (7) Coating condition (e.g., visual, jeeping).
  (8) Photographic documentation (e.g., visual history).
  (9) Sketch of site with dimensions and findings.
  (10) Other data deemed appropriate (e.g., location of excavation).

  Note: NACE Appendices A and B provide additional examples of data to collect.

  If the coating is found to be in good shape and no other data indicate that external corrosion is present, no additional action is required. The operator may consider removing the coating to obtain additional data.

(c) Coating damage or exposed pipe surface. If the coating is damaged or corrosion is present on the pipe, examples of data and related activities that may be performed at each excavation include the following.
  (1) Verify coating type.
  (2) Verify coating condition and adhesion (e.g., holidays, blisters, cracking, sagging, disbondment).
  (3) Pipe-to-soil potentials (e.g., ground level surface and at the pipe surface to determine cathodic protection level).
  (4) Pipe wall thickness (e.g., ultrasonic testing).
  (5) Corrosion byproduct (e.g., carbonate or iron oxide deposits, biofilms).
  (6) Types of corrosion defects (e.g., single pit, localized pitting, general corrosion).
  (7) Non-corrosion defects or damage (e.g., arc burn, dent, lamination).
  (8) Mapping and measurement of defects or damage. The pipe surface should be properly prepared and the corrosion defects cleaned. The following should be considered when measuring defects.
    (i) Shape.
    (ii) Depth.
    (iii) Length.
    (iv) Width.
    (v) Orientation (e.g., circumferential, longitudinal).
    (vi) Location on pipe (e.g., clock position).
    (vii) Distance from girth and seam welds.
    (viii) Distance from other reference points.
    (ix) Distance between corrosion pits.
  (9) Photographic documentation with scale reference.
  (10) Other data deemed appropriate (e.g., pH in the corrosion pit).

  Note: NACE Appendix C provides additional data collection guidance.

(d) Supplemental data collection.
  (1) In accordance with NACE 5.4.3.5, the operator shall consider other evaluations unrelated to external corrosion. Such evaluations may include magnetic particle or dye penetrant testing for cracks.
  (2) If conditions are found that indicate severe coating damage or significant corrosion defects are suspected beyond either side of the excavation, the excavation should be extended and measurements taken. See guide material under §192.459.

(3) When the pipe is exposed, visual inspection for pipeline coating damage threats other than external corrosion, such as third-party damage, is required. As required by §192.925(b), if the ECDA detects pipeline coating damage, the operator must feedback the data from the ECDA with other information from the data integration process (§192.917(b)) to evaluate the covered segment for the threat of third-party damage, and to address the threat as required by §192.917(e)(1).

5.4 Evaluation of indications.

(a) Corrosion defects. In accordance with NACE 5.6.1, the pipeline operator must evaluate the condition of the coating and pipe wall at each excavation location.

(b) If corrosion is found at indications, the pipeline operator must evaluate or calculate the remaining strength at locations where corrosion defects are found. Examples of corrosion defects that need remaining strength evaluation include the following.
(1) A corrosion defect exceeding 20% of the pipe wall thickness.
(2) Cluster of pits.

The remaining wall strength should be evaluated. Types of evaluation can include ASME B31G, PRCI PR-3-805 (RSTRENG) (see §192.7), or an equivalent method. If the remaining strength is not adequate for the pipeline segment's existing maximum allowable operating pressure (MAOP), a repair, replacement, or MAOP reduction is required. Alternatively, the operator may temporarily reduce the operating pressure of the pipeline as allowed by §192.933.

(c) Similar defects. If corrosion defects that exceed allowable limits are found, it should be assumed that other similar defects may be present elsewhere in the ECDA region. This assumption should be based on similar characteristics of the region in which the corrosion defect was found. The following actions should be considered when a corrosion defect is found that exceeds allowable limits to assist in determining if a similar defect is present.
(1) Perform root-cause analysis.
(2) Evaluate the criteria used to define the ECDA region.
(3) Evaluate the criteria used to define indications.
(4) Perform a direct examination on remaining indications with similar characteristics.

5.5 Root-cause analysis.

(a) In accordance with NACE 5.6.1, the pipeline operator shall identify the root cause of all significant corrosion activity. Typical examples of root causes include the following.
(1) Insufficient or inadequate cathodic protection.
(2) Previously unidentified sources of stray current interference.
(3) Cathodic protection current shielding (e.g., coating disbondment).
(4) Microbiologically influenced corrosion (MIC).
(5) Poorly applied coating.

(b) If it is determined that the root cause is one for which ECDA is not feasible, such as CP shielding by disbonded coating or MIC, the operator is required to consider alternative methods of assessing the integrity of the covered segment. Examples of alternative methods include ILI, pressure testing, or other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe (§192.921(a)(4)).

(c) The operator is required to document root-cause identifications and analyses (NACE 7.4.1.3).

5.6 Mitigation (remediation).

(a) In accordance with NACE 5.7.1, the operator is required to identify and implement remediation activities to mitigate or preclude future external corrosion resulting from significant root causes. Examples of remediation activities include the following.
(1) Increasing cathodic protection.
(2) Adding insulators.

(3) Adding interference bonds.

(b) To determine the effectiveness of the remediation the operator may choose to repeat indirect inspections after remediation activities.

5.7 *In-process criteria evaluation, reprioritization, and reclassification.*

NACE 5.8 requires the operator to evaluate the indirect inspection data versus the results of remaining strength evaluation and the root-cause analysis by comparing the actual conditions found to the conditions predicted by the criteria used to classify and categorize indications. This evaluation should be conducted periodically throughout the direct examination step so that operator can make adjustments to its criteria to adequately address the threat of external corrosion. These direct examination tasks may require that certain indications need to have their severity classification or priority category raised. Based on the results of the evaluation an operator may downgrade an indication's classification or categorization.

(a) Reclassification of indications.
  (1) NACE 5.9 requires the operator to reclassify indications when results from the direct examination show corrosion activity (e.g., corrosion, coating damage) that is worse than indicated by the indirect inspection data. The classification criteria shall be reevaluated and adjusted to reflect the severity of indications found.
  (2) If corrosion or coating damage was found worse than what was classified, NACE 5.8.4.3.1 requires the operator to consider the need for additional indirect inspections over the ECDA region. Factors to consider whether additional indirect inspections are needed include:
    (i) Corrosion found was localized versus widespread.
    (ii) Coating damage was localized versus widespread.
    (iii) Indirect inspection tool determined not to be well suited for the site conditions.
    (iv) Number of indirect inspection tools to be used.
  (3) If the corrosion activity is less severe than what was classified, an operator may adjust the criteria used to define the severity of all indications. Additionally, consideration may be given to adjust the criteria used to prioritize the need for repair.
  (4) If repeated direct examinations show corrosion activity that is worse than Indicated by the indirect inspection data, the operator is required to reevaluate the feasibility of ECDA (NACE 5.8.4.4).
(b) Reprioritization of excavations.
  (1) NACE 5.9 requires the operator to reprioritize when existing corrosion is more severe than the assigned priority. For example, if examination of a "scheduled" indication reveals an external corrosion defect that requires immediate action, the prioritization criteria is required to be revised so the "scheduled" indication would be prioritized as "immediate."
  (2) If an indication was categorized as immediate, scheduled, or monitored but no corrosion or coating damage was discovered during the direct examination, the operator may consider redefining its categorization criteria.
  (3) An indication that was originally placed in the immediate category cannot be moved lower than the scheduled category as a result of reprioritization unless the operator documents justification that demonstrates the technical basis for lowering the category (NACE 5.9.1.1).
  (4) When ECDA is applied for the first time, NACE 5.9.1.2 does not allow the pipeline operator to downgrade any indications that were originally placed in the immediate or scheduled priority category to a lower priority category unless the operator documents justification that demonstrates the technical basis for lowering the category.
  (5) Things to consider when reprioritization is needed.
    (i) Direct examination findings against the interpretation of tool measurements.
    (ii) How the environment affects the tool response.
    (iii) Evaluate tool application procedures.
    (iv) Trending of findings.
(c) Root cause.

  For each root cause where corrosion activity was worse than expected, indications that occur in the pipeline segment where similar root-cause conditions exist (e.g., foreign line crossing, light rail) shall be identified and reevaluated (NACE 5.9.3).

(vi) Severe indications.
(vii) Moderate indications.
(viii) Minor indications.
(ix) Coating damages found.

(c) An operator should evaluate the performance measure results by comparing previous assessment results for trending purposes. An increased number of indications between assessments may not necessarily mean that the ECDA process is ineffective. An operator may consider the following when performing the evaluation.
(1) Pipeline failures between assessments.
(2) Changes in prioritization criteria.
(3) Expected aging effects on the coating.
(4) Increased construction activity (e.g., light rail).
(5) Significant changes to the pipeline environment.
(6) Additions to the pipeline.
(7) Suburban sprawl.

(d) In the event that the evaluation of performance measures does not show ECDA to be effective, the pipeline operator is required to reevaluate the ECDA application or consider alternative methods of assessing pipeline integrity unless the operator provides written justification (NACE 6.4.4).

6.5 Feedback (continuous improvement).

(a) NACE 6.5.1 requires the operator to endeavor to improve the ECDA process by providing opportunities to evaluate feedback from applicable processes.

(b) NACE 6.5.2 requires the operator to consider including the following activities in the feedback process.
(1) Indication severity classification and priority categories.
(2) Data collection during direct examinations.
(3) In-process criteria evaluations.
(4) Remaining strength evaluations.
(5) Root-cause analyses.
(6) Remediation activities.
(7) Criteria for monitoring long-term ECDA effectiveness (e.g., reclassifications, reprioritizations).
(8) Reassessment criteria.
(9) Periodic reassessments.
(10) Interactive threats.

(c) An operator should verify that applicable records have been updated with the information captured from applicable forms and records.

7 RECORDKEEPING

(a) See NACE 7 for recordkeeping requirements.
(b) ECDA records that are pertinent to the pre-assessment, indirect inspection, direct examination, and post-assessment steps should be documented in a clear, concise, and workable manner.
(c) Records of each ECDA step may be maintained at a central location, or at multiple locations.
(d) Records may be maintained either electronically, as paper copies, or in any other appropriate format.

8 REFERENCES

(a) AGA Pipeline Research Committee Project PR-3-805, "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," (RSTRENG) (see §192.7).
(b) ASME B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines." (see §192.7).
(c) NACE SP0502-2010, "Pipeline External Corrosion Direct Assessment Methodology." (see §192.7).
(d) PHMSA-OPS Protocols, "Gas Integrity Management Inspection Manual, Inspection Protocols with Results Forms," specifically Section D, DA Plan.
(e) GTI-04/0071, "External Corrosion Direct Assessment (ECDA) Implementation Protocol."
(f) NACE SP0113, “Pipeline Integrity Method Selection.”

(g) NACE SP0207, "Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines."
(h) NACE TM0109, "Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition."
(i) NACE TM0497, "Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems."
(j) PHMSA-OPS, "Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs."

§192.927

What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

[Effective Date: 05/24/23]

(a) ***Definition*****. Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.**

(b) ***General requirements*****. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in NACE SP0206 (incorporated by reference, *see* §192.7). The Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) process described in this section applies only for a segment of pipe transporting normally dry natural gas (*see* § 192.3), and not for a segment with electrolytes normally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolytes present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to address internal corrosion effectively, and notify PHMSA in accordance with § 192.18. In the event of a conflict between this section and NACE SP0206, the requirements in this section control.**

(c) ***The ICDA plan*****. An operator must develop and follow an ICDA plan that meets NACE SP0206 (incorporated by reference, see § 192.7) and that implements all four steps of the DG-ICDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. The plan must identify the locations of all ICDA regions within covered segments in the transmission system. An ICDA region is a continuous length of pipe (including weld joints), uninterrupted by any significant change in water or flow characteristics, that includes similar physical characteristics or operating history. An ICDA region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur until a new input introduces the possibility of water entering the pipeline. In cases where a single covered segment is partially located in two or more ICDA regions, the four-step ICDA process must be completed for each ICDA region in which the covered segment is partially located to complete the assessment of the covered segment.**

(1) ***Preassessment*****. An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in conducting the preassessment step of the ICDA process.**

(2) ***Indirect Inspection*****. An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7), and the following additional requirements, in conducting the Indirect Inspection step of the ICDA process. An operator must explicitly document the results of its feasibility assessment as required by NACE SP0206, section 3.3 (incorporated by reference, see § 192.7); if any condition that precludes the successful application of ICDA applies, then ICDA may not be used, and another assessment method must be selected. When performing the indirect inspection, the operator must use actual pipeline-specific data, exclusively. The use of assumed pipeline or operational data**

is prohibited. When calculating the critical inclination angle of liquid holdup and the inclination profile of the pipeline, the operator must consider the accuracy, reliability, and uncertainty of the data used to make those calculations, including, but not limited to, gas flow velocity (including during upset conditions), pipeline elevation profile survey data (including specific profile at features with inclinations such as road crossings, river crossings, drains, valves, drips, etc.), topographical data, and depth of cover. An operator must select locations for direct examination and establish the extent of pipe exposure needed (i.e., the size of the bell hole), to account for these uncertainties and their cumulative effect on the precise location of predicted liquid dropout.

(3) *Detailed examination*. An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in conducting the detailed examination step of the ICDA process. When an operator first uses ICDA for a covered segment, an operator must identify a minimum of two locations for excavation within each covered segment associated with the ICDA region and must perform a detailed examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement techniques that can examine for internal corrosion or other threats that are being assessed. One location must be the low point (e.g., sag, drip, valve, manifold, dead-leg) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within the covered segment, near the end of the ICDA Region. Whenever corrosion is found during ICDA at any location, the operator must:

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933 if the condition is in a covered segment, or in accordance with §§ 192.485 and 192.714 if the condition is not in a covered segment;

(ii) Expand the detailed examination program to determine all locations that have internal corrosion within the ICDA region, and accurately characterize the nature, extent, and root cause of the internal corrosion. In cases where the internal corrosion was identified within the ICDA region but outside the covered segment, the expanded detailed examination program must also include at least two detailed examinations within each covered segment associated with the ICDA region, at the location within the covered segment(s) most likely to have internal corrosion. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region. The second location must be further downstream, within the covered segment. In instances of first use of ICDA for a covered segment, where these locations have already been examined in accordance with paragraph (c)(3) of this section, two additional detailed examinations must be conducted within the covered segment; and

(iii) Expand the detailed examination program to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region in which the corrosion was found, remediate identified instances of internal corrosion in accordance with either §192.933; or §§ 192.485 and 192.714, as appropriate.

(4) *Post-assessment evaluation and monitoring*. An operator must comply with NACE SP0206 (incorporated by reference, see § 192.7) in performing the post assessment step of the ICDA process. In addition to NACE SP0206, the evaluation and monitoring process must also include~~s~~ —

(i) An evaluation of the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within one year of conducting an ICDA; and

(ii) Validation of the flow modeling calculations by comparison of actual locations of discovered internal corrosion with locations predicted by the model (if the flow model cannot be validated, then ICDA is not feasible for the segment); and

(iii) Continuous monitoring of each ICDA region that contains a covered segment where internal corrosion has been identified by using techniques such as coupons or ultrasonic (UT) sensors or electronic probes, and by periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart~~,~~ and risk factors specific to the ICDA region. At a minimum, the monitoring frequency must be two times each calendar year, but at intervals not

exceeding 7½ months. If an operator finds any evidence of corrosion products in the ICDA region, the operator must take prompt action in accordance with one of the two following required actions, and remediate the conditions the operator finds in accordance with §192.933 or §§ 192.485 and 192.714, as applicable.

(A) Conduct excavations of, and detailed examinations at, covered segments at locations downstream from where the electrolytes might have entered the pipe to investigate and accurately characterize the nature, extent, and root cause of the corrosion, including the monitoring and mitigation requirements of § 192.478; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements*. The ICDA plan must also include the following:

(i) Criteria an operator will apply in making key decisions (including, but not limited to, ICDA feasibility, definition of ICDA regions and sub-regions, and conditions requiring excavation) in implementing each stage of the ICDA process; and

(ii) Provisions that the analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.

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GUIDE MATERIAL

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 PURPOSE

Internal Corrosion Direct Assessment (ICDA) is used to assess the integrity of the pipe that is subject to the threat of internal corrosion. ICDA is a process that identifies areas along the transmission pipeline where a liquid containing an electrolyte may exist, and then focuses direct examination of the locations in covered segments where internal corrosion is most likely to exist.

2 GENERAL REQUIREMENTS

(a) A written ICDA plan should include its purpose, objectives, and instructions to personnel and must be based on the requirements of the following.
   (1) Section 192.927.
   (2) ASME B31.8S, Paragraph 6.4 and Appendix B2.
   (3) GRI-02/0057 (see §192.7 for IBR), or its equivalent.
(b) For the purpose of this guide material, ICDA is applicable to transmission pipelines that normally carry dry gas but may have experienced infrequent introductions (upsets) of electrolytes into the system.
(c) A separate ICDA plan is required for a pipeline that carries electrolytes in the gas stream (i.e., wet gas). If ICDA is used as an integrity assessment under this condition, the operator is required to notify PHMSA and, if applicable, the state agency 180 days before conducting the ICDA. See §192.927(b) and guide material under §§192.921, 192.937, and 192.949.
(d) Where a covered segment is present, the ICDA region includes the portion of the pipeline from each location where an electrolyte may first enter the pipeline upstream of any covered segment (input) to the farthest downstream point from the input where internal corrosion might have occurred (even if this point is downstream of the covered segment).

(e) Other pipeline integrity threats, such as external corrosion or mechanical damage, may be discovered in the direct examination phase of ICDA. When such threats are detected, alternative or additional methods for assessments may be required.
(f) ICDA consists of four steps:
   (1) Pre-assessment.
   (2) ICDA region identification.
   (3) Identification of locations for excavation and direct examination.
   (4) Post-assessment evaluation and monitoring.
(g) When conducting ICDA for the first time on a covered segment, an operator is required to apply more restrictive criteria that should be considered for each step of the ICDA process (see §192.927(c)(5)(ii)).

(h) In accordance with §192.947, each decision, analysis, and process developed to support each step is required to be documented.

3 PRE-ASSESSMENT

The objective of pre-assessment is to gather data for the determination of ICDA feasibility.

3.1 Data collection.
(a) This step involves collecting, reviewing, and integrating historical data for the pipeline segment. Data may be obtained from various sources including the following.
   (1) Operating and maintenance records.
   (2) Field visits.
   (3) Alignment sheets.
   (4) Risk assessment process.
   (5) Input from subject matter experts.
   (6) Other relevant information.
(b) To assist in data collection, an operator should prepare a facility description and collect related historical data on operations and inspections, including upsets and repairs. The data collected in the pre-assessment step often includes the same data typically considered during an overall pipeline threat assessment. The pre-assessment step may be conducted in conjunction with ECDA or other threat assessment efforts.
(c) In accordance with §192.927(c)(1) and ASME B31.8S, Appendix A2, the information in Table 192.927i is required to be collected, integrated, and assessed to determine where internal corrosion is likely to occur.

INFORMATION FOR ICDA		
Data Element	**ICDA Influence**	**Key Decision Points & Comments**
Installation date	Affects the length of time a pipe is exposed to potential corrosion.	ICDA can be conducted if installation date is unknown.
Pipe inspection reports	Provide data on prior internal corrosion.	All available reports should be reviewed. Determine if internal corrosion has been detected. Clock position of prior internal corrosion may help determine ICDA feasibility. The location of internal corrosion (e.g., bottom or top of pipe) may provide information regarding the mechanism of corrosion.
Leak history	Provides data on prior internal corrosion.	Leak data should be reviewed for evidence of internal corrosion.
Wall thickness	Affects the remaining strength and has a minor effect on the critical angle.	Wall thickness records may be contained in work order files or other historical files. If actual wall thickness is unknown, the operator should assign a thinner wall thickness based on historical data. Changes in wall thickness may affect ICDA regions.
Diameter	Affects the remaining strength calculations and is a major factor in determining critical angles.	Diameter records may be contained in work order files, mapping system, or other historical files. If pipe diameter is unknown, confirmation of diameter should be performed prior to conducting ICDA.

TABLE 192.927i (Continued)

INFORMATION FOR ICDA (Continued)

Data Element	ICDA Influence	Key Decision Points & Comments
Internal coating	Internal coating will inhibit corrosion.	Internal coating makes it difficult to determine where corrosion may occur and may make ICDA unsuitable.
Past hydrostatic test information	Inadequate cleaning may have left water in the pipe.	Pipelines that have been recently hydrotested may still contain water in locations downstream of critical angles. Source of the water is also a concern. Treated municipal water is less likely to cause corrosion than water taken from a stream or lake. Consideration should be given to check the moisture content of the pipeline.
Gas, liquid, and solids analysis, including bacterial test results	Prior sampling data provides an indication of whether conditions support internal corrosion.	All available reports should be reviewed. Gas sources should be considered. One formation may produce gas with higher H_2S concentrations than another, so the source of gas should be considered. Liquid analysis could help determine whether corrosive conditions exist. Operators should determine whether accumulations of solids are significant enough to influence the validity of ICDA results. Solids analysis may also indicate type or cause of internal corrosion (e.g., carbonate solids may indicate high CO_2 concentrations in gas, and sulfides may indicate microbiologically influenced corrosion (MIC)). See NACE SP0206, Paragraph 3.3.7.
Internal corrosion probes and coupons	Weight loss coupons or probes are used to monitor corrosion rates.	All available reports should be reviewed. If internal corrosion is present downstream of the critical angle, then ICDA may not be feasible.
Flow velocity	Gas flow rate is a major factor in determining how far electrolytes will travel in a pipeline. Changes in flow velocity might allow liquids to accumulate.	Flow velocity is a critical factor in determining where fluid may collect in a pipeline system. High winter velocities might clean lines, while low summer velocities might allow liquids to accumulate. Line diameter variations change velocity.
Operating pressure	Operating pressure affects the flow velocity and operating stress level.	Pressure affects gas density, which influences gas velocity and the critical angle.
Proximity to treatment facilities and compressor stations	Hot gas coming from a compressor station can speed up corrosion rates.	Corrosion rates double with a 10-degree temperature increase. Hot gas or warm fluids (such as those produced from a deep well) will increase the risk of internal corrosion.
Operating stress level	Stress level is a major factor in determining risk and remaining life.	If pipe grade is unknown, conservative assumptions should be made. See §192.107(b)(2).

TABLE 192.927i (Continued)

INFORMATION FOR ICDA (Continued)

Data Element	ICDA Influence	Key Decision Points & Comments
Location of all gas input points	Gas input locations determine ICDA regions.	Review maps and historic system flows to determine all input points for the pipeline of interest. Production gas may contain higher concentrations of both gas and entrapped contaminants. Recent well treatments may cause an increase in liquids (particularly unspent acid) or solid contaminants. Well treatment fluids may also react with pipeline debris, creating additional problems. Storage field delivery locations may affect internal corrosion downstream, especially during withdrawal season. Comingled gas may reduce corrosion effects.
Location of all gas withdrawal points	Major withdrawal points could reduce gas velocity downstream.	Review maps and system flow models, if available, to determine all significant withdrawal points. Examples of withdrawal points include feeds to distribution centers, industrial customers, storage fields, and large load commercial customers. Also, consider the seasonal nature of withdrawal points. Individual residential customers do not have a significant effect on flow velocity and critical angles.
Location of drips, valves, dead legs, freeze locations, or other features	Drips, valves, dead legs, tapping fittings, low spots, and other features are locations where fluid may collect.	Review maps, system flow models, if available, and as-built drawings to determine locations. These points might require direct examination if they are on pipe within an HCA.
Elevation profile, including low spots and streams	Used to determine angle of inclination.	Elevation profiles may be obtained using GPS and depth of cover or by using topographic maps. Changes in depth of cover must be considered when determining the elevation profile. Due to deeper burial depths, examples of pipeline profiles of interest include: directional drilling and crossings of waterways, highways, railroads, pipelines, other utilities, culverts, and landfills.
Operating history indicating historic upsets in gas conditions	Upsets or bypass of fluid removal systems might introduce water, glycol, or other contaminants into the pipeline.	Available reports should be reviewed. Operators may determine that fluid removal systems (e.g., dehydration units, separators, filters) operated by other gas suppliers are sufficient in providing dry gas.
Use of cleaning pigs for liquid removal	Cleaning pigs might push fluid past the critical angle.	Routine use of cleaning pigs might affect ICDA. The operator should provide technical justification when ICDA is applied to a pipeline that has a history of using cleaning pigs. For example, the justification may need to address how an operator is evaluating low points other than those near the critical angle.

TABLE 192.927i (Continued)

(b) Region identification.
  (1) For identification of locations for excavation and direct examination, taking additional data to better define the inclination profile of a pipeline such as decreasing the distance between survey points.
  (2) Running the flow model at a range of flow rates to determine the sensitivity of the critical angle to various flow conditions experienced over time.
(c) Identification of locations for excavation and direct examination.
  (1) Performing additional excavations.
  (2) Extending the length of an excavation to evaluate more pipe.
  (3) Using multiple NDT methods to inspect the pipe.
(d) Post-assessment and monitoring
  (1) Periodically analyzing gas and liquid samples.
  (2) Installing internal corrosion monitoring equipment, even if no internal corrosion is found.
  (3) Increasing the frequency of monitoring gas samples, liquid samples, or corrosion detection devices if corrosion is found.
(e) Other criteria the operator deems applicable to the pipeline conditions.

8 RECORDKEEPING

(a) ICDA records that are pertinent to the pre-assessment, ICDA region identification, identification of locations for excavation and direct examination, and post assessment and monitoring steps should be documented in a clear, concise, and workable manner.
(b) Records may be maintained at a central location or at multiple locations.
(c) Records may be maintained either electronically, as paper copies, or in any other appropriate format.
(d) See NACE SP0206, Section 7 for additional recordkeeping guidance.

9 REFERENCES

(a) ASME B31.8S, "Managing System Integrity of Gas Pipelines."
(b) GRI-02/0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology."
(c) NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)."
(d) NACE SP0502, "Pipeline External Corrosion Direct Assessment Methodology."
(e) PHMSA-OPS, "Gas Integrity Management Protocols with Guidance," Protocol Area D, DA Plan.

§192.929

What are the requirements for using Direct Assessment for Stress Corrosion Cracking?

[Effective Date: 05/24/23]

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

(b) *General requirements*. An operator using direct assessment as an integrity assessment method for addressing SCC in a covered pipeline segment must develop and follow an SCCDA plan that meets NACE SP0204 (incorporated by reference, see § 192.7) and that implements all four steps of the SCCDA process, including pre-assessment, indirect inspection, detailed examination at excavation locations, and post-assessment evaluation and monitoring. As specified in NACE SP0204, SCCDA is complementary with other inspection methods for SCC, such as in-line inspection or

hydrostatic testing with a spike test, and it is not necessarily an alternative or replacement for these methods in all instances. Additionally, the plan must provide for—

(1) *Data gathering and integration*. An operator's plan must provide for a systematic process to collect and evaluate data for all covered pipeline segments to identify whether the conditions for SCC are present and to prioritize the covered pipeline segments for assessment in accordance with NACE SP0204, sections 3 and 4, and Table 1 (incorporated by reference, see § 192.7). This process must also include gathering and evaluating data related to SCC at all sites an operator excavates while conducting its pipeline operations (both within and outside covered segments) where the criteria in NACE SP0204 (incorporated by reference, *see* §192.7), indicate the potential for SCC. This data gathering process must be conducted in accordance with NACE SP0204, section 5.3 (incorporated by reference, see § 192.7), and must include~~s~~, at minimum, all data listed in NACE SP0204, Table 2 (incorporated by reference, see § 192.7). Further, the following factors must be analyzed as part of this evaluation:

(i) The effects of a carbonate-bicarbonate environment, including the implications of any factors that promote the production of a carbonate-bicarbonate environment, such as soil temperature, moisture, the presence or generation of carbon dioxide, or cathodic protection (CP);

(ii) The effects of cyclic loading conditions on the susceptibility and propagation of SCC in both high-pH and near-neutral-pH environments;

(iii) The effects of variations in applied CP, such as overprotection, CP loss for extended periods, and high negative potentials;

(iv) The effects of coatings that shield CP when disbonded from the pipe; and

(v) Other factors that affect the mechanistic properties associated with SCC, including, but not limited to, historical and present-day operating pressures, high tensile residual stresses, flowing product temperatures, and the presence of sulfides.

(2) *Indirect inspection*. In addition to NACE SP0204, the plan's procedures for indirect inspection must include provisions for conducting at least two above ground surveys using the complementary measurement tools most appropriate for the pipeline segment based on an evaluation of integrated data.

(3) *Direct examination*. In addition to NACE SP0204, the plan's procedures for direct examination must provide for an operator conducting a minimum of three direct examinations for SCC within the covered pipeline segment spaced at the locations determined to be the most likely for SCC to occur.

(4) *Remediation and mitigation*. If SCC is discovered in a covered pipeline segment, an operator must mitigate the threat in accordance with one of the following applicable methods:

(i) Removing the pipe with SCC; remediating the pipe with a Type B sleeve; performing hydrostatic testing in accordance with paragraph (b)(4)(ii) of this section; or by grinding out the SCC defect and repairing the pipe. If an operator uses grinding for repair, the operator must also perform the following as a part of the repair procedure: nondestructive testing for any remaining cracks or other defects; a measurement of the remaining wall thickness; and a determination of the remaining strength of the pipe at the repair location that is performed in accordance with § 192.712 and that meets the design requirements of §§ 192.111 and 192.112, as applicable. The pipe and material properties an operator uses in remaining strength calculations must be documented in traceable, verifiable, and complete records. If such records are not available, an operator must base the pipe and material properties used in the remaining strength calculations on properties determined and documented in accordance with § 192.607, if applicable.

(ii) Performing a spike pressure test in accordance with § 192.506 based upon the class location of the pipeline segment. The MAOP must be no greater than the test pressure specified in § 192.506(a) divided by: 1.39 for Class 1 locations and Class 2 locations that contain Class 1 pipe that has been uprated in accordance with § 192.611; and 1.50 for all other Class 2 locations and all Class 3 and Class 4 locations. An operator must repair any test failures due to SCC by replacing the pipe segment and re-testing the segment until the pipe passes the test without failures (such as pipe seam or gasket leaks, or a pipe rupture). At a minimum, an operator must repair pipe segments that pass the pressure test but have SCC present by grinding the segment in accordance with paragraph (b)(4)(i) of this section.

(5) *Post assessment*. An operator's procedures for post-assessment, in addition to the procedures listed in NACE SP0204, sections 6.3, "periodic reassessment," and 6.4, "effectiveness of SCCDA," must include the development of a reassessment plan based on the susceptibility of the operator's pipe to SCC as well as the mechanistic behavior of identified cracking. An operator's reassessment intervals must comply with § 192.939. The plan must include the following factors, in addition to any factors the operator determines appropriate:

(i) The evaluation of discovered crack clusters during the direct examination step in accordance with NACE SP0204, sections 5.3.5.7, 5.4, and 5.5 (incorporated by reference, see § 192.7);

(ii) Conditions conducive to the creation of a carbonate-bicarbonate environment;

(iii) Conditions in the application (or loss) of CP that can create or exacerbate SCC;

(iv) Operating temperature and pressure conditions, including operating stress levels on the pipe;

(v) Cyclic loading conditions;

(vi) Mechanistic conditions that influence crack initiation and growth rates;

(vii) The effects of interacting crack clusters;

(viii) The presence of sulfides; and

(ix) Disbonded coatings that shield CP from the pipe.

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GUIDE MATERIAL

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, unless another edition is noted (e.g., ASME B31.8S-2010). Section 192.929(b) requires that the operator comply with the IBR edition of ASME B31.8S, Appendix A3 even though Appendix A is titled as "non-mandatory." See 3.2 of the guide material under §192.907.

1 PURPOSE

Stress Corrosion Cracking Direct Assessment (SCCDA) is a method to assess the integrity of steel pipe that is subject to the threat of stress corrosion cracking (SCC).

2 GENERAL REQUIREMENTS

(a) A written SCCDA plan should include the purpose, objectives, and instructions to personnel and is required to meet the following.
  (1) Section 192.929.
  (2) ASME B31.8S, Appendix A3.
(b) In accordance with §192.929, an SCCDA plan must provide for the following.
  (1) Data gathering and integration.
    (i) Collect and evaluate data for all covered segments to identify whether the conditions for SCC are present.
    (ii) Prioritize the covered segments for assessment.
  (2) Assessment method.
    (i) Assess the covered segment using an integrity assessment method specified in ASME B31.8S, Appendix A3.
    (ii) Remediate the SCC threat in accordance with ASME B31.8S, Appendix A3.4.
(c) In accordance with ASME B31.8S, Appendix A3.5, when an operator discovers data that may be pertinent to other threats, the operator is required to use the data to perform risk assessments for those other threats.

(d) The SCCDA plan should consider integrity assessment for other threats and prioritization of segments that are at risk for SCC.
(e) The current regulations apply to both near-neutral pH SCC and high pH SCC; however, ASME B31.8S, Appendix A3 does not currently address near-neutral pH SCC. In accordance with NACE SP0204, the same factors and criteria can be used to select pipeline segments to assess for either type of SCC, except that the temperature criterion does not apply to near-neutral pH SCC.

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 be taken to address integrity issues?

[Effective Date: 05/24/23]

(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. Repairs performed in accordance with this section must use 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.

(1) *Temporary pressure reduction.*

(i) 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 reduce the operating pressure to one of the following:

(A) A level not exceeding 80 percent of the operating pressure at the time the condition was discovered.

(B) A level not exceeding the predicted failure pressure times the design factor for the class location in which the affected pipeline is located, or

(C) A level not exceeding the predicted failure pressure divided by 1.1.

(ii) An operator must determine the predicted failure pressure in accordance with § 192.712. An operator must notify PHMSA in accordance with § 192.18 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) or (d) of this section and cannot provide safety through a temporary reduction in operating pressure or other action. The operator must document and keep records of the calculations and decisions used to determine the reduced operating pressure, and the implementation of the actual reduced operating pressure, for a period of 5 years after the pipeline has been remediated.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 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. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an

intrastate covered segment is regulated by that State.

(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. For the purposes of this section, 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 (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. In cases where a determination is not made within the 180- day period, the operator must notify PHMSA, in accordance with § 192.18, and provide an expected date when adequate information will become available. Notification to PHMSA does not alleviate an operator from the discovery requirements of this paragraph (b).

(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 §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 (incorporated by reference, *see* § 192.7) 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 metal loss anomaly where a calculation of the remaining strength of the pipe shows a predicted failure pressure determined in accordance with § 192.712(b) less than or equal to 1.1 times the MAOP at the location of the anomaly.

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) Metal loss greater than 80 percent of nominal wall regardless of dimensions.

(iv) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure determined in accordance with § 192.712(d) is less than 1.25 times the MAOP.

(v) A crack or crack-like anomaly meeting any of the following criteria:

(A) Crack depth plus any metal loss is greater than 50 percent of pipe wall thickness;

(B) Crack depth plus any metal loss is greater than the inspection tool's maximum measurable depth; or

(C) The crack or crack-like anomaly has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.25 times the MAOP.

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

(2) *One-year conditions*. Except for conditions listed in paragraphs (d)(1) and (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 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(ii) A dent with a depth greater than 2 percent 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 or helical (spiral) seam weld, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iii) A dent located between the 4 o'clock and 8 o'clock positions (lower 1/3 of the pipe) that has metal loss, cracking, or a stress riser, unless engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(iv) Metal loss anomalies where a calculation of the remaining strength of the pipe at the location of the anomaly shows a predicted failure pressure, determined in accordance with §192.712(b), less than 1.39 times the MAOP for Class 2 locations, and less than 1.50 times the MAOP for Class 3 and 4 locations. For metal loss anomalies in Class 1 locations with a predicted failure pressure greater than 1.1 times MAOP, an operator must follow the remediation schedule specified in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 7, Figure 4, in accordance with paragraph (c) of this section.

(v) Metal loss that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or could affect a girth weld, that has a predicted failure pressure, determined in accordance with § 192.712(b), of less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure, determined in accordance with § 192.712(d), is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vii) A crack or crack-like anomaly that has a predicted failure pressure, determined in accordance with § 192.712(d), that is less than 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or less than 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(3) *Monitored conditions*. An operator is not required by this section to schedule remediation of the following less severe conditions but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation. Monitored indications are the least severe and do not require an operator to examine and evaluate them until the next scheduled integrity assessment interval, but if an anomaly is expected to grow to dimensions or have a predicted failure pressure (with a safety factor) meeting a 1-year condition prior to the next scheduled assessment, then the operator must repair the condition:

(i) A dent with a depth greater than 6 percent 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), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(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 percent of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and for which engineering analyses of the dent, performed in accordance with § 192.712(c), demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2 percent of the pipeline 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 or helical (spiral) seam weld, and for which engineering analyses, performed in accordance with § 192.712(c), of the dent and girth or seam weld demonstrate that critical strain levels are not exceeded.

(iv) A dent that has metal loss, cracking, or a stress riser, and where engineering analyses performed in accordance with § 192.712(c) demonstrate critical strain levels are not exceeded.

(v) Metal loss preferentially affecting a detected longitudinal seam, if that seam was formed by direct current, low-frequency or high-frequency electric resistance welding, electric flash welding, or with a longitudinal joint factor less than 1.0, and where the predicted failure pressure,

determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(vi) A crack or crack-like anomaly for which the predicted failure pressure, determined in accordance with § 192.712(d), is greater than or equal to 1.39 times the MAOP for Class 1 locations or where Class 2 locations contain Class 1 pipe that has been uprated in accordance with § 192.611, or greater than or equal to 1.50 times the MAOP for all other Class 2 locations and all Class 3 and 4 locations.

(e) *In situ direct examination of crack defects*. Whenever an operator finds conditions that require the pipeline to be repaired, in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects using technology that has been validated to detect tight cracks (equal to or less than 0.008 inches crack opening), such as inverse wave field extrapolation (IWEX), phased array ultrasonic testing (PAUT), ultrasonic testing (UT), or equivalent technology. "In situ" examination tools and procedures for crack assessments (length, depth, and volumetric) must have performance and evaluation standards, including pipe or weld surface cleanliness standards for the inspection, confirmed by subject matter experts qualified by knowledge, training, and experience in direct examination inspection for accuracy of the type of defects and pipe material being evaluated. The procedures must account for inaccuracies in evaluations and fracture mechanics models for failure pressure determinations.

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REMEDIATION OF DENTS (Continued)			
Pipe Size	**Dent Location**	**Description**	**Schedule**
Equal to or greater than 12"	Any	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.	One year
	Any	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.	Monitor
	Top 2/3 of pipe	A smooth dent with a depth[1] greater than 6% of the pipe diameter with no engineering analysis.	One year
	Top 2/3 of pipe	A dent with a depth[1] greater than 6% of the pipe diameter and engineering analysis demonstrates critical strain levels are not exceeded.	Monitor
	Bottom 1/3 of pipe	A dent with a depth[1] greater than 6% of the pipe diameter.	Monitor
[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 (§192.933(a)(2)) to provide notification (see §192.18). The notification must (§192.933(a)(2)) 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: 05/24/23]

(a) ***General requirements.***

(1) An operator must take additional measures beyond those already required by this part to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. Measures that operators must consider in the analysis, if necessary, to prevent or mitigate the consequences of a pipeline failure include, but are not limited to:

(i) Correcting the root causes of past incidents to prevent recurrence;

(ii) Establishing and implementing adequate operations and maintenance processes that could increase safety;

(iii) Establishing and deploying adequate resources for the successful execution of preventive and mitigative measures;

(iv) Installing automatic shut-off valves or remote-control valves;

(v) Installing pressure transmitters on both sides of automatic shut-off valves and remote control valves that communicate with the pipeline control center;

(vi) Installing computerized monitoring and leak detection systems;

(vii) Replacing pipe segments with pipe of heavier wall thickness or higher strength;

(viii) Conducting additional right-of-way patrols;

(ix) Conducting hydrostatic tests in areas where pipe material has quality issues or lost records;

(x) Testing to determine material mechanical and chemical properties for unknown properties that are needed to assure integrity or substantiate MAOP evaluations, including material property tests from removed pipe that is representative of the in-service pipeline;

(xi) Re-coating damaged, poorly performing, or disbonded coatings;

(xii) Performing additional depth-of-cover surveys at roads, streams, and rivers;

(xiii) Remediating inadequate depth-of-cover;

(xiv) Providing additional training to personnel on response procedures and conducting drills with local emergency responders; and

(xv) Implementing additional inspection and maintenance programs.

(2) Operators must document the risk analysis, the preventive and mitigative measures considered, and the basis for implementing or not implementing any preventive and mitigative measures considered, in accordance with § 192.947(d).

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

(c) *Risk analysis for gas releases and protection against ruptures.* If an operator determines, based on a risk analysis, that a rupture-mitigation valve (RMV) or an alternative equivalent technology would be an efficient means of adding protection to a high-consequence (HCA) area in the event of a gas release, an operator must install the must install the RMV or alternative equivalent technology. In making that determination, an operator must, at least, consider the following factors — timing 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. An RMV or alternative equivalent technology installed under this paragraph must meet all of the other applicable requirements in this part.

(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; and

(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 instrumented leak surveys using leak detector equipment at least twice each calendar year, at intervals not exceeding 7 1/2 months For unprotected pipelines or cathodically protected pipe where electrical surveys are impractical, instrumented leak surveys must be performed at least four times each calendar year, at intervals not exceeding 4 1/2 months. Electrical surveys are indirect assessments that include close interval surveys, alternating current voltage gradient surveys, direct current voltage gradient surveys, or their equivalent.

(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.

(f) *Periodic evaluations.* Risk analyses and assessments conducted under paragraph (c) of this section must be reviewed by the operator and certified by a senior executive of the company, for operational matters that could affect rupture-mitigation processes and procedures. Review and certification must occur once per calendar year, with the period between reviews not to exceed 15 months, and must also occur within 3 months of an incident or safety-related condition, as those terms are defined at §§ 191.3 and 191.23, respectively.

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GUIDE MATERIAL

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.

(b) Use a central database to collect the following.
(1) Excavation damage information for covered and non-covered segments. This might include the following.
(i) Number of leaks or ruptures.
(ii) Number of known damages not resulting in leaks or ruptures.
(iii) Excavation method.
(iv) Name of excavator causing damage.
(2) Root-cause analysis data to identify targeted P&M measures for HCAs. This might include the number of damages where:
(i) No line locate was requested.
(ii) Line was incorrectly marked.
(iii) Line was not marked.
(iv) Construction procedures were not followed correctly (e.g., exposing lines during boring).
(3) Damage data that is not DOT reportable (reference Part 191 requirements). This might include known items such as the following.
(i) Dents.
(ii) Gouges.
(iii) Coating damage.
(iv) Damage to pipeline supports or river anchors.

(c) Participate in a one-call program wherever there are covered segments.

(d) 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 using one or more of the following.
(i) Time card accounting.
(ii) Special forms.
(iii) Time-stamped electronic data.
(iv) Maps.

(e) When there is physical evidence of an excavation near a covered segment that the operator did not monitor, either excavate the area or conduct an aboveground survey (e.g., DCVG) as defined in NACE SP0502-2010 (see §192.7 for IBR). Examples of how to identify an encroachment might 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.

3 OUTSIDE FORCE DAMAGE (§192.935(b)(2))

To comply with §192.935(b)(2) for the specific threat of outside force damage (e.g., earth movement, floods, unstable suspension bridge), an operator must take additional measures to minimize the consequences of outside force.

(a) The measures include the following.
(1) Increasing the frequency of patrols to allow faster for recognition of damage.
(2) Adding external protection. This might include the following.

(i) Installing fencing or other barriers to impede earth movement.
(ii) External slabs or additional cover.
(iii) Add erosion protection such as riprap.

(3) Reducing external stress. This might include the following.
(i) Installing expansion joints.
(ii) Removing overburden.

(4) Relocating the pipeline to an area with less exposure to outside forces. This might include lowering or raising the pipeline.
(5) Conducting inline inspections to determine whether geometric deformation has occurred.

(b) An operator might also consider installing the following.
(1) River anchors where appropriate.
(2) Elevated relief or vent stacks on regulator stations.
(3) Additional bridge hangers or pipe supports.
(4) Identifying geodetic monitoring points (e.g., survey benchmarks) to track potential ground movement.
(5) Installing slope inclinometers to track ground movement at depth which might otherwise not be detectable during ROW patrols.
(6) Installing standpipe piezometers to track changes in groundwater conditions that might affect slope stability.
(7) Evaluating the accumulation of strain in the pipeline by installing strain gauges on the pipeline.
(8) Conducting stress-strain analysis using in-line inspection tools equipped with inertial mapping unit technology and high-resolution deformation in-line inspection for pipe bending and denting from movement.
(9) Using aerial mapping light detection and ranging or other technology to track changes in ground conditions.

4 PIPELINES OPERATING BELOW 30 PERCENT SMYS (§192.935(d))

Pipelines operating below 30% SMYS have additional requirements as addressed below. For guidance related to these additional requirements, see Appendix E to Part 192.

(a) For all Class locations in an HCA, the following apply.
(1) Qualify personnel to conduct the following activities related to work the operator is conducting in a covered segment.
(i) Locating the pipeline.
(ii) Marking the pipeline.
(iii) Directly supervising known excavation work. A qualification for this activity might include the following.
(A) Recognition of line-locate markings.
(B) Knowledge of one-call requirements.
(C) Knowledge of operator's applicable procedures, including emergency response.
(D) Understanding the risks of various excavation methods.
(iv) Other activities that could adversely affect the integrity of the pipeline.
(2) Participate in a one-call program wherever there are covered segments.
(3) Either monitor excavations near the pipeline, or conduct patrols on a bi-monthly frequency. Any indication of unreported construction activity requires an investigation to determine if any damage has occurred.

(b) For Class 3 or Class 4 locations outside of an HCA.
(1) Qualify personnel to conduct the following activities related to work the operator is conducting in covered segment.
(i) Locating the pipeline.
(ii) Marking the pipeline.
(iii) Directly supervising known excavation work. A qualification for this activity might include the following.
(A) Recognition of line-locate markings.
(B) Knowledge of one-call requirements.
(C) Knowledge of operator's applicable procedures, including emergency response.

(D) Understanding the risks of various excavation methods.

(iv) Other activities that could adversely affect the integrity of the pipeline.

(2) Participate in a one-call program wherever there are covered segments.

(3) Either monitor excavations near the pipeline, or conduct patrols on a bi-monthly frequency. Any indication of unreported construction activity requires an investigation to determine if any damage has occurred.

(4) Perform semi-annual leak surveys. For unprotected or cathodically protected pipe where electrical surveys are impractical, perform quarterly leak surveys.

(c) See Table 192.935i.

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.

3 NEED FOR MORE FREQUENT ASSESSMENT

The reassessment intervals listed in Tables 192.939i through 192.939iv represent the maximum interval between assessments. Reassessment at a shorter interval should be considered for any of the following.

(a) The operator plans on increasing the MAOP of the pipeline.
(b) The stresses leading to cyclic fatigue are increased, and the pipe is subject to manufacturing threats (e.g., low-frequency ERW seams), construction threats (e.g., wrinkle bends), or other similar threats.
(c) A failure has occurred on the pipeline segment.
(d) Failure on another pipeline segment with similar characteristics that could indicate a similar threat to the covered segment.
(e) Known defects that need to be addressed prior to the maximum reassessment interval.

4 PERFORMANCE-BASED PROGRAMS

The maximum reassessment intervals listed in Tables 192.939i through 192.939iv may be exceeded by an operator that can demonstrate exceptional performance as listed in §192.913(b). One requirement for using a performance-based program is that the operator must have completed at least 2 assessments for each covered segment to be included in the performance-based program. When using longer assessment intervals under a performance-based program, an operator must be able to provide analysis supporting the longer interval, and must perform confirmatory direct assessment at intervals not exceeding 7 calendar years (§192.939(a) and (b)). Operators may request a 6-month extension of the 7-calendar-year reassessment interval if the operator submits written notice to PHMSA-OPS, in accordance with §192.18, with sufficient justification of the need for the extension (§192.939(a) and (b)).

5 WAIVER (SPECIAL PERMIT) FOR DEVIATION FROM REASSESSMENT INTERVALS

Operators can apply to PHMSA-OPS for waivers (special permits) if the reassessment interval cannot be met due to lack of availability of assessment tools or the need to maintain product supply. See §192.943 for the waiver process and §190.341 for the required content of applications for special permits.

§192.941

What is a low stress reassessment?

[Effective Date: 05/24/23]

(a) *General*. An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with §192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§192.919 and 192.921.

(b) *External corrosion*. An operator must take one of the following actions to address external corrosion on the low stress covered segment.

(1) *Cathodically protected pipe*. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an indirect assessment on the covered segment at least every once 7 calendar years. The indirect assessment must be conducted using one of the following means: indirect examination method, such as a close interval survey; alternating current voltage gradient survey; direct current voltage gradient survey; or the equivalent of any of these methods. An operator must evaluate the cathodic protection and corrosion threat for the covered segment and include the results of each indirect assessment as part of the overall evaluation. This evaluation must also include, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where external corrosion assessments*

***are impractical*. If an external corrosion assessment is impractical on the covered segment an operator must —**

(i) Conduct leakage surveys as required by §192.706 at 4-month intervals; and

(ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(c) *Internal Corrosion*. To address the threat of internal corrosion on a covered segment, an operator must —

(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)- (c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

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GUIDE MATERIAL

1 GENERAL

Low stress reassessment is an integrity assessment method that may be used by an operator to address the threats of external corrosion and internal corrosion. This method can only be used for transmission lines operating below 30% SMYS. Prior to applying this method, the operator is required to complete a baseline integrity assessment in accordance with §§192.919 and 192.921. The low stress reassessment is required at intervals not exceeding 7 years, and a full reassessment (in-line inspection, pressure test, or direct assessment) is required no more than 20 years after the previous full assessment. Appendix E to Part 192 (Tables E.II.2 and E.II.3) provides guidance on low stress reassessment.

2 EXTERNAL CORROSION

2.1 Cathodically protected pipe where electrical surveys are practical.

(a) If low stress reassessment is used on cathodically protected pipe, an electrical survey (i.e., indirect examination tool or method) is required. Examples of electrical surveys are listed below. NACE SP0207, "Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines" and NACE TM0109, "Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition" provides additional information on each type of survey listed.
   (1) Close-interval survey (CIS).
   (2) Current voltage gradient surveys (ACVG and DCVG).
   (3) Pearson survey.
   (4) Alternating current attenuation survey (electromagnetic).
   (5) Cell-to-cell survey.

(b) An operator should have procedures to conduct an electrical survey. The following factors should be considered when developing written procedures.
   (1) Electrical safety precautions.
   (2) Equipment and instrumentation.
   (3) IR drop considerations, where applicable.
   (4) Locating and marking pipe.
   (5) Distance between survey points.

(6) Data documentation.
(7) Data analysis.
(8) Remediation criteria.
(9) Post-assessment analysis.

2.2 Unprotected pipe or cathodically protected pipe where electrical surveys are impractical.

(a) Leak surveys. See guide material under §192.706 and the applicable sections of Guide Material Appendix G-192-11.
(b) Areas of active corrosion. See guide material under §192.465.
(c) For conditions where electrical-type surveys may be impractical, see 3(b) of the guide material under §192.465.

2.3 Overall evaluation.

An overall evaluation of the external corrosion threat is required. This evaluation should consider the following.

(a) Leak repair records. See guide material in Guide Material Appendix G-192-11 for examples of types of records that may be considered.
(b) Inspection records. Examples of these types of records may include prior assessments, patrolling, leak surveys, and continuing surveillance activities. See guide material under §§192.613, 192.705, and in Guide Material Appendix G-192-17.
(c) Corrosion monitoring records. See guide material under §192.491.
(d) Exposed pipe records. See guide material under §192.459.
(e) Pipeline environment. The operator should consider the following factors in regards to the pipeline environment.
    (1) Soil resistivity (high or low).
    (2) Soil moisture (wet or dry).
    (3) Soil types (e.g., rocky, sandy, clay, loam).
    (4) Land use that may result in soil contaminants that promote corrosive activity, (e.g., spill areas, industrial sites, agricultural sites, land fills).
    (5) Unusual soil conditions (e.g., swamps, peat bogs, cinders, foreign fill).
    (6) Other known conditions that could affect the probability of corrosion, (e.g., soil pH, bacteria).

3 INTERNAL CORROSION

(a) See guide material under §192.475 for information on gas and liquid analysis, and appropriate remediation (mitigative) actions. Gas and liquid samples should be taken at locations representative of operating conditions for the covered segment.
(b) The operator is required to integrate data from the gas and liquid analysis and testing with other internal corrosion information listed below.
    (1) Internal corrosion leak records. For examples of the types of records that may be considered, see Guide Material Appendix G-192-11, Section 6.
    (2) Incident reports. See guide material under §191.15.
    (3) Safety-related condition reports. See guide material under §§191.23 and 191.25.
    (4) Repair records. See Guide Material Appendix G-192-17.
    (5) Exposed pipe records. See guide material under §192.475.
    (6) Analysis and testing records. These records may include coupon analysis results or other records that might indicate the potential for internal corrosion.

§192.943

When can an operator deviate from these reassessment intervals?

[Effective Date: 04/06/04]

(a) *Waiver from reassessment interval in limited situations*. In the following limited instances, OPS may allow a waiver from a reassessment interval required by §192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.

(1) *Lack of internal inspection tools*. An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) *Maintain product supply*. An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(b) *How to apply*. If one of the conditions specified in paragraph (a)(1) or (a)(2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004 and Amdt. 192-95 Correction & Petition for Reconsideration, 69 FR 18228, Apr. 6, 2004]

GUIDE MATERIAL

Note: Section 192.943 still uses the term "wavier" so this term is used below and in the guide material under §192.939. A "waiver" is now referred to as a "special permit" by PHMSA-OPS (see §190.341). State terminology may differ (e.g., waiver, variance).

1 GENERAL

PHMSA-OPS may issue waivers (special permit) in limited instances. A waiver is not required in the following situations.

(a) When reassessment intervals established are more frequent than those required by §192.939.
(b) Where an integrity management program meets the criteria for exceptional performance in §192.913.

2 CONDITIONS FOR A WAIVER

A waiver can be requested under the following conditions.

(a) Unavailability of internal inspection tools.
Operators may consider a general contract provision with their internal inspection tool service provider that requires written notification of tool availability. However, to support the request for waiver, an operator should consider obtaining documentation on the lack of availability from multiple vendors. This documentation might include the following.
(1) Request for Proposal (RFP).
(2) Letters from vendors.
(3) Timeline of activities.
(b) Inability to maintain supply.
An operator should consider submitting documentation substantiating the basis and possible duration that local gas supply cannot be maintained. Documentation might include the following.
(1) Operational flow control notifications from an upstream pipeline operator.
(2) Supply nominations.
(3) SCADA system data (i.e., flow rates and pressures).
(4) Weather conditions.

(5) Potential customer outages.
(6) Upstream service interruptions.
(7) Natural disasters.

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.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004 and Amdt. 192-95 Correction & Petition for Reconsideration, 69 FR 18228, Apr. 6, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-115, 75 FR 72878, Nov. 26, 2010]

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. Also, the instructions are included (with the form) in Guide Material Appendix G-191-6.

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 Paragraph 6.7 of NACE SP0502-2010 (see §192.7 for IBR).

§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.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004 and Amdt. 192-95 Correction & Petition for Reconsideration, 69 FR 18228, Apr. 6, 2004]

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.

1.14 OTHER DOCUMENTS (Continued)		
GRI-91/0285.1	Executive Summary: Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways	GMA G-192-15
GRI-95/0171	State-of-the-Art Review and Analysis of Guided Drilling Systems	GMA G-192-15B
GRI-96/0368	Guidelines for the Application of Guided Horizontal Drilling to Install Gas Distribution Pipe	GMA G-192-15B
IAPMO	Uniform Plumbing Code	§192.141
ISO 31000	Risk Management – Guidelines	§192.12
ISO 31010	Risk Management – Risk assessment techniques	§192.12
ISO 55000	Asset Management	§192.12
NCB	Subsidence Engineers' Handbook, National Coal Board Mining Department (U.K.), 1975	GMA G-192-13
NFPA 10	Portable Fire Extinguishers	
NFPA 14	Installation of Standpipe and Hose Systems	§192.141
NFPA 24	Installation of Private Fire Service Mains and Their Appurtenances	§192.141
NFPA 54/ANSI Z223.1	National Fuel Gas Code	Figure 192.11A Figure 192.11B §192.629
NFPA 220	Types of Building Construction	
NFPA 224	Homes and Camps in Forest Areas (Discontinued)	§192.163
NFPA 921	Guide for Fire and Explosion Investigations	§192.617
OTD-12/0003	Cross Bore Best Practices – Best Practices Guide (prepared by GTI)	§192.614 GMA G-192-6
PRCI L22279	Further Studies of Two Methods for Repairing Defects in Line Pipe	§192.713
PRCI L51406	Pipeline Response to Buried Explosive Detonations	GMA G-192-16
PRCI L51574	Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement	GMA G-192-13
PRCI L51717	Pipeline In-Service Relocation Engineering Manual	§192.703
PRCI L51725	Drilling Fluids in Pipeline Installation by Horizontal Directional Drilling-A Practical Applications Manual	GMA G-192-15A GMA G-192-15B
PRCI L51740	Evaluation of the Structural Integrity of Cold Field-Bent Pipe	§192.313
Table Continued		

1.14 OTHER DOCUMENTS		
PRCI L52047	Pipeline Repair Manual (PR-218-9307)	§192.613 §192.713 §192.929
PRCI L52292	Guidelines for Constructing Pipelines Through Areas Prone to Landslide and Subsidence Hazards	§192.103
PRCI PC-PISCES	Personal Computer - Pipeline Soil Crossing Evaluation System (PC-PISCES), Version 2.0 (Related to API RP 1102)	GMA G-192-15
PRCI PR-277-144507	Installation of Pipelines Using Horizontal Directional Drilling – An Engineering Design Guide	GMA G-192-15A GMA G-192-15B
UL 723	Test for Surface Burning Characteristics of Building Materials	§192.163

2 GOVERNMENTAL DOCUMENTS (Continued)		
OPS ADB-11-02	Advisory Bulletin – Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems (76 FR 7238, Feb. 9, 2011)	§192.616
OPS ADB-2012-02	Advisory Bulletin – Post-Accident Drug and Alcohol Testing (77 FR 10666, Feb. 23, 2012)	§192.605 §192.615
OPS ADB-2012-03	Advisory Bulletin – Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation (77 FR 13387, Mar. 6, 2012)	§192.613 §192.917
OPS ADB-2012-07	Advisory Bulletin – Completion of Mechanical Fitting Failure Report Form, Leak Causes (77 FR 34457, June 11, 2012)	§191.12
OPS ADB-2012-08	Advisory Bulletin – Inspection and Protection of Pipeline Facilities after Railway Accidents (77 FR 45417, July 31, 2012)	§192.615
OPS ADB-2012-10	Advisory Bulletin – Using Meaningful Metrics in Conducting Integrity Management Program Evaluations (77 FR 72435, Dec. 5, 2012)	GMA G-192-3
OPS ADB-2012-11	Advisory Bulletin – Reporting of Exceedances of Maximum Allowable Operating Pressure (77 FR 75699, Dec. 21, 2012)	§191.23
OPS ADB-2014-03	Advisory Bulletin – Construction Notification (79 FR 54777, Sept. 12, 2014	§191.22
OPS ADB-2014-05	Advisory Bulletin – Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics (79 FR 61937, Oct. 15, 2014)	GMA G-192-3
OPS ADB-2015-02	Advisory Bulletin – Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes (80 FR 36042, June 23, 2015)	§192.615
OPS ADB-2016-05	Advisory Bulletin – Clarification of Terms Relating to Pipeline Operational Status (81 FR 54512, August 16, 2016)	§192.727
OPS ADB-2019-01	Advisory Bulletin – Potential for Damage to Pipeline Facilities Caused by Severe Flooding (84 FR 14715, April 11, 2019)	§192.613 §192.615
OPS ADB-2019-02	Advisory Bulletin – Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards (84 FR 18919, May 2, 2019)	§192.613
OPS ALN-88-01	Alert Notice – Operational failures of pipelines constructed with ERW prior to 1970 (Jan 28, 1988; see document at PHMSA-OPS website)	§192.917

Table Continued

2 GOVERNMENTAL DOCUMENTS (Continued)		
OPS ALN-89-01	Alert Notice – Update to ALN-88-01 (Mar 8, 1989; see document at PHMSA-OPS website)	§192.917
OPS-DOT.RSPA/DMT 10-85-1	Safety Criteria for the Operation of Gaseous Hydrogen Pipelines (Discontinued)	§192.1
OPS TTO No. 5	Technical Task Order – Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Michael Baker Jr., Inc., et al	§192.917
OPS TTO No. 8	Technical Task Order – Stress Corrosion Cracking Study, Michael Baker, Jr., Inc., January 2005	§192.613 §192.917 §192.929
PHMSA-OPS	Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators	GMA G-192-8
	Gas Integrity Management Protocols	§192.925 §192.927
	Guidance Manual for Operators of LP Gas Systems	§192.1 §192.11 §192.616 GMA G-192-8
	Guidance Manual for Operators of Small Natural Gas Systems	§192.1 §192.616 GMA G-192-8
	Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs	§192.925
	Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics	GMA G-192-3
	"Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Gas Pipelines"	§192.620
	Notice – Development of Class Location Change Waiver Criteria (69 FR 38948, June 29, 2004)	§192.611
	Operator Qualification Guidance Manual for Operators of LP Gas Systems	§192.11 §192.801
	Operator Qualification Guide for Small Distribution Systems	§192.801

Table Continued

(b) Where the bore will run parallel to an existing facility, expose that facility (pothole) or use locating technology to verify that adequate clearance is maintained between the bore and the existing facility during the boring operation, which includes the drilling of the pilot hole and back reaming. Calculation of the separation distance should account for the largest diameter back reamer that will be used in the boring process.
(c) Potholes used for visual inspection should be excavated at intervals ensuring clearance is maintained during boring operations. Factors to consider for pothole intervals include the following.
   (1) Proximity of proposed bore path to the existing gas facilities.
   (2) Type of existing and proposed facilities.
   (3) Type of soil.
   (4) Size and controllability of the bore.
(d) Locating existing facilities and the newly installed facility to ensure that the installation is in the intended location.
(e) If metallic facilities are exposed, see guide material under §192.459.
(f) Conducting a leak survey over gas facilities that could have been affected by the new installation.

4 PROTECTING GAS FACILITIES INSTALLED BY DIRECTIONAL DRILLING

Warning tape is not generally used when installing gas facilities by directional drilling or other trenchless technologies. In addition to markers required by §192.707, the operator should consider placing extra line markers along the route after the pipe is installed. See Guide Material Appendix G-192-13, Section 3.

GUIDE MATERIAL APPENDIX G-192-7

(See guide material under §192.615)

LARGE-SCALE DISTRIBUTION OUTAGE RESPONSE AND RECOVERY

1 SCOPE

This Guide Material Appendix provides guidance to operators of distribution systems for restoring gas service to customers should a large-scale outage occur. This guide material is a supplement to the guide material under §192.615. This appendix should be used in conjunction with the guide material found under §§192.615 and 192.629 that details certain steps of the response and restoration process. Considering the various causes of outages, these guidelines are generic in nature. Each operator should determine what constitutes a large-scale outage considering factors such as system size, number of customers, and operational response potential.

2 GENERAL

2.1 Emergency plan.

Basic plans for recovery from large-scale outages should be made by the operator prior to the actual event. Section 192.615(a)(9) requires the operator to establish procedures for safely restoring any service outage. A large-scale outage recovery plan developed under this guide material is not intended to supersede an operator's existing emergency plans. In some cases, an outage recovery plan may better define the roles and responsibilities of various organizations.

2.2 Causes of a large-scale service outage.

There are many causes of system outages that would result in the interruption of gas service to customers. Knowledge of the outage cause will provide the operator the ability to determine a course of action appropriate to the circumstances. Causes of large-scale service outages may include the following.

(a) Natural disasters.
   (1) Tornadoes.
   (2) Hurricanes.
   (3) Wild fires.
   (4) Earthquakes.
   (5) Flooding.
   (6) Extreme weather resulting in planned rolling electric blackouts or unplanned electric system outages.
(b) System failures.
   (1) Mechanical failures, such as regulator or other equipment malfunctions.
   (2) Third-party damage.
   (3) Pipeline rupture.
   (4) Overpressurization.
   (5) Water infiltration into gas system.
   (6) Gas supply shortage.
(c) Human.
   (1) Vandalism.
   (2) Civil defense emergency.
   (3) Incorrect operation.

2.3 Basic considerations.

Each large-scale outage scenario presents the operator with unique challenges. However, there are basic actions that can be taken to assure safe and timely recovery. Action items to consider include the following.

(a) Identify and assess the cause(s) of the outage.
(b) Verify the situation will not become unstable or further affect system gas pressure conditions.

9 REPORT RESULTS

10 REPORT FITTING FAILURES

11 SAMPLE DIMP APPROACHES

11.1 SME approach.

11.2 Mathematical approach.

1 INTRODUCTION

1.1 Scope.

(a) This guide material is intended to assist operators with development of a Distribution Integrity Management Program (DIMP), including the written plan, and compliance with Federal Regulations §§192.1001, 192.1003, 192.1005, 192.1007, 192.1009, 192.1011, and 192.1015 on DIMP. It provides operators with practices that may be considered as they develop and maintain a DIMP specific to their gas distribution systems.

(b) Distribution pipeline systems and associated operating practices can vary widely. Examples of system differences include: materials used, age, manner of construction, operation and maintenance practices, and operating environments (natural and man-made). This guidance recognizes that there is wide diversity among distribution systems and is therefore flexible, allowing operators to identify considerations dealing with their unique threats and to select actions suited to their specific needs.

(c) The options in this guidance are intended to provide the operator with a selection of possible choices to use in improving the integrity of its distribution system. Operators may not need to consider or perform every step presented. It is not intended that an operator evaluate every option or provide justification or reasons why options were not implemented.

(d) Section 192.1003 exempts master meter systems and individual service lines directly connected to a transmission, gathering, or production pipeline. Most of these types of service lines are commonly known as "farm taps". Farm taps can be excluded from DIMP requirements if they are being maintained in accordance with §192.740(a) and (b).

(e) Section 192.1015 imposes different requirements for small liquefied petroleum gas (LPG) operators (i.e., those serving fewer than 100 customers from a single source). Since these pipeline systems are less complex, the integrity management requirements are simplified. The appropriate portions of this guide material are valid for those operators. PHMSA-OPS has published the following documents to assist operators of small LPG systems to implement requirements of the DIMP rule:

(1) "Distribution Integrity Management: Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators"
Guidance for Carrying Out Requirements in the Gas Distribution Integrity Management Rule (2013) | PHMSA (dot.gov)).

(2) "Guidance Manual for Operators of Small Natural Gas Systems"
(https://www.phmsa.dot.gov/training/pipeline/guidance-manuals).

(3) "Guidance Manual for Operators of LP Gas Systems"
(https://www.phmsa.dot.gov/training/pipeline/guidance-manuals).

1.2 Glossary of Abbreviations.

Abbreviation	Meaning
A/A	additional or accelerated (actions)
CP	cathodic protection
DIMP	Distribution Integrity Management Program
LPG	liquefied petroleum gas
PE	polyethylene
SCADA	supervisory control and data acquisition
SDR	standard dimension ratio
SME	subject matter expert

1.3 How to use this guide material.

The guide material is organized to coincide with the seven required elements of a DIMP. The order in which the guidance is presented does not imply the order in which it should be applied. However, the operator needs to address each element in some way. Once an operator determines how it can best accomplish distribution system integrity, the guide material may be used to support or direct the operator's approach. The operator is cautioned that the guide material may not anticipate all conditions that may be encountered, and the operator is not restricted from using other methods to comply with the Regulations.

Two sample DIMP approaches are given in Section 11.

1.4 Overview.

(a) The objective of a DIMP is to manage the integrity of a gas distribution system. As discussed in detail in Section 5, an essential part of a DIMP is a risk evaluation of the distribution system. One approach to risk evaluation is to group facilities by common traits or problems, and then perform a risk ranking. This process allows the grouping of facilities that experience similar threats to be risk-ranked together. Then, if necessary, attention can be focused on developing measures that address the greatest risks.

(b) After identifying the problems, the operator should consider the concept of grouping facilities when first developing its DIMP. Such groupings could significantly affect how the operator assembles data about its system (see Section 3) and how it approaches its threat analysis (see Section 4).

(c) The operator should also recognize that the development of the DIMP may be an iterative (or repeating) process. That means each time a cycle (e.g., gather knowledge, identify threats, rank risks, take action to reduce risk, measure performance) is completed, areas needing additional data, analyses, or actions may become apparent. For example, the initial general knowledge of the system may be used to group facilities, identify the applicable threats, and begin the risk analysis. In attempting to complete the risk analysis, the operator may determine the need for additional information. The operator may also determine that the facility groupings need to be redefined, such as by subdividing groups or combining groups.

2 ELEMENTS OF A DISTRIBUTION INTEGRITY MANAGEMENT PLAN

2.1 General.

Seven elements have been identified as the essential components of a DIMP, except as modified for those operators identified in §192.1015(a). Collectively, these elements establish a program that should reasonably manage the integrity of distribution pipeline systems on a going-forward basis. These elements are as follows.

(a) Knowledge (see Section 3).
(b) Identify threats (see Section 4).
(c) Evaluate and rank risk (see Section 5).
(d) Identify and implement measures to address risks (see Section 6).
(e) Measure performance, monitor results, and evaluate effectiveness (see Section 7).
(f) Periodic evaluation and improvement (see Section 8).
(g) Report results, except for small LPG operators (see Section 9).

2.2 Develop and implement a written plan.

Federal Regulations require that each distribution operator prepare and implement a written plan as a primary component of its DIMP. The function of the plan is to document how each of the applicable seven elements will be addressed and implemented. The plan should be complete and address required elements by the implementation dates in §§192.1005 and 192.1015. The plan should be concise, but still be sufficient for operator personnel to understand and implement the program on a consistent basis, and is not intended to include extensive technical justifications or detailed process descriptions.

3 KNOWLEDGE

3.1 General.

(a) Information, such as the materials and type of construction, the operating conditions of the pipe or facility, and other relevant factors within the surroundings in which the system operates, is referred to as the "knowledge of the distribution system."

(b) General knowledge of the system will assist the operator to identify threats and establish which facilities or groups of facilities [1], if desired, should be subject to risk evaluation (see Sections 4 and 5).

(c) Records of the distribution systems may exist in many forms (e.g., paper, electronically) and in the knowledge and experience of operations, maintenance, construction, installation, design, or engineering personnel. Information from these sources may be evaluated to assist in developing an operator's DIMP.

(d) The operator should use the best information available to make decisions about what is in the existing system and to assess the applicable threats and risks to the gas distribution system. In some cases, an operator may be unable to determine the materials or characteristics of some of the components in the system. This may be due to lost records, systems gained through mergers or acquisitions without complete records, or other reasons. For example, the year of installation might be used to make such decisions about piping material, joint type, coating type, or repair methods used.

(e) Information about an existing system should be updated when new or better information becomes available. This information should be gathered during existing operating or maintenance activities and installation of new facilities on an existing infrastructure. At a minimum, §192.1007(a)(5) requires the location and material of construction for new piping and appurtenances to be recorded.

(f) Operators may not have all desired records initially, but can still develop a DIMP. An operator would not have to dig up its system just to collect information, but when an operator inspects the pipe wherever it is exposed, the operator should use the occasion to record and evaluate any distribution system unknowns that are available at that location.

(g) To the extent possible, the operator should use information collection procedures that are already in place. New collection activities should be developed only if the existing procedures are not adequate for the operator's DIMP. If the information is adequate, the manner in which it is compiled and organized may need modification to make it more usable. Note, however, that O&M records retention requirements under DIMP exceed the retention requirements that may have been in place prior to DIMP. Certain O&M records used to support integrity management plans, including superseded plans, are required to be maintained for at least 10 years (§192.1011). Therefore, an operator might need to modify the collection and retention procedures that are in place.

(h) System knowledge should be based on reasonably available information, and could include concurrent records such as leak and repair records, as well as analyses of that information. Information from replaced or abandoned facilities could be relevant for evaluating risks to existing facilities with similar characteristics, construction methods, or environmental factors. If such records are used to demonstrate compliance, they are subject to the record retention requirement of §192.1011.

3.2 DOT Annual Report information.

(a) Basic knowledge of what is in the distribution system is contained in the operator's annual report to DOT (PHMSA Form F 7100.1-1). All past report data is available for download from the PHMSA-OPS website www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids. The operator should review the source and accuracy of the most recent annual report information and take actions to ensure that the information is current and accurate. Report forms and instructions are available for download at the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.

(b) "Part B - System Description" of the Annual Report provides a breakdown of the mains and service lines in the distribution system by material, diameter, and installation decade.

[1] *Facilities may be individual components or units (e.g., a particular district regulating station, an entire low-pressure distribution system). Groups of facilities generally have common traits (e.g., physical similarities such as the same pipe material or a particular type of valve) or common problems (e.g., small diameter cast iron pipe experiencing cracking, regulators that will not hold set point).*

(1) Section 1 of Part B – System Description specifically provides the total miles of main and number of service lines in the following material categories:

PART B - SYSTEM DESCRIPTION	**Report miles of main and number of services in system at end of year.**										
1. GENERAL											
	STEEL				PLASTIC	CAST/ WROUGHT IRON	DUCTILE IRON	COPPER	OTHER	Reconditioned Cast Iron	SYSTEM TOTAL
	UNPROTECTED		CATHODICALLY PROTECTED								
	BARE	COATED	BARE	COATED							
MILES OF MAIN											
NO. OF SERVICES											

(2) Sections 2 and 3 of Part B require the operator to break down the total miles of main and the total number of services by diameter ranges. The diameter ranges for steel mains and service lines are not separated by the presence of cathodic protection or coating.

2. MILES OF MAINS IN SYSTEM AT END OF YEAR							
MATERIAL	**UNKNOWN**	**2" OR LESS**	**OVER 2" THRU 4"**	**OVER 4" THRU 8"**	**OVER 8" THRU 12"**	**OVER 12"**	**SYSTEM TOTALS**
STEEL							
DUCTILE IRON							
COPPER							
CAST/WROUGHT IRON							
PLASTIC 1. PVC							
2. PE							
3. ABS							
4. OTHER PLASTIC							
OTHER							
Reconditioned Cast Iron							
SYSTEM TOTALS							

Describe Other Material:

3. NUMBER OF SERVICES IN SYSTEM AT END OF YEAR					**AVERAGE SERVICE LENGTH ______ FEET**		
MATERIAL	**UNKNOWN**	**1" OR LESS**	**OVER 1" THRU 2"**	**OVER 2" THRU 4"**	**OVER 4" THRU 8"**	**OVER 8"**	**TOTAL**
STEEL							
DUCTILE IRON							
COPPER							
CAST/WROUGHT IRON							
PLASTIC 1. PVC							
2. PE							
3. ABS							
4. OTHER PLASTIC							
OTHER							
Reconditioned Cast Iron							
SYSTEM TOTALS							

Describe Other Material:

(3) The Annual Report form requires operators to provide the miles of main and number of service lines by decade of installation in Section 4 of Part B.

4. MILES OF MAIN AND NUMBER OF SERVICES BY DECADE OF INSTALLATION											
	UN-KNOWN	PRE-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	TOTAL
MILES OF MAIN											
NUMBER OF SERVICES											

(c) "Part C – Total Leaks and Hazardous Leaks Eliminated/Repaired During Year" provides a breakdown of eliminated/repaired leaks by leak cause for mains and for service lines, and the number of known system leaks scheduled for repair. See 3.4 below.

3.3 *Additional information.*
In addition to the Annual Report information, an operator should review other records for additional information to evaluate significant threats.

Local system personnel may provide additional information about the system. For example, field personnel might know of construction techniques that were not recorded. When developing knowledge of its distribution system, an operator should consider the following.

(a) Pipe specifications and component information, including diameter, grade or yield strength, and wall thickness for steel pipe; manufacturer and Standard Dimension Ratio (SDR) for plastic pipe; size, location, and type for valves and pressure regulators.
(b) Construction specifics, such as year installed, joining method (e.g., type of coupling, welded, fusion) and installation method (e.g., open trench, plow, boring, directional drilling, casings, cast iron on concrete blocks).
(c) Corrosion control systems, which may be composed of coating (e.g., coal tar, fusion bond epoxy, wax), cathodic protection (e.g., galvanic or impressed current), electrical isolation devices, year of installation (e.g., years without cathodic protection), stray current mitigation (e.g., diodes, bonds), and aboveground corrosion control practices.
(d) Threats that could degrade pipelines over time such as the following.
    (1) Repeated ground disturbances (e.g., tidal surges, flooding, subsidence, downslope movement, frost heaves, settling, earthquakes).
    (2) Multiple failures of the CP system, which can lead to corrosion (e.g., rectifier power failures, ground bed degradation, CP system short).
    (3) Gas composition upsets (e.g., microorganisms, liquids, CO2, O2, hydrogen sulfide).
    (4) Repeated water intrusion into low pressure metallic distribution lines.
    (5) Repeated external loading including blasting.

3.4 *Knowledge of what is physically happening in the system.*
The records containing important information may include leak records, repair work orders, corrosion inspection and work records, incident reports, third-party damage reports, material failure reports, pipe condition reports, equipment maintenance records, inspection records, maintenance records, or others for appropriate historical time frames.

(a) To determine what is happening in and to the distribution system, the operator should consider information gathered through routine operations and maintenance activities, as well as any special field surveys or patrols (e.g., as-needed post-flooding or winter (frost) patrols). The information may come from the following.
    (1) Results of inspections and surveys.
        (i) Leak surveys.
        (ii) Corrosion inspections.
        (iii) Patrols.
        (iv) Continuing surveillance.

(v) Liquids removal.

(2) Documentation of leaks and other maintenance performed.

(i) Repairs.

(ii) Corrosion control systems.

(iii) Equipment or component replacements.

(iv) Material failure reports.

(v) Incident reports.

(vi) Part C of the Annual Report, which provides the number of leaks eliminated/repaired by cause of leak category. These categories are the minimum threats that need to be evaluated in an operator's DIMP. See Section 4.

PART C - TOTAL LEAKS AND HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING YEAR				
CAUSE OF LEAK	Mains		Services	
	Total	Hazardous	Total	Hazardous
CORROSION FAILURE				
NATURAL FORCE DAMAGE				
EXCAVATION DAMAGE				
OTHER OUTSIDE FORCE DAMAGE				
PIPE, WELD, OR JOINT FAILURE				
EQUIPMENT FAILURE				
INCORRECT OPERATION				
OTHER CAUSE				
NUMBER OF KNOWN SYSTEM LEAKS AT END OF YEAR SCHEDULED FOR REPAIR				

(3) Excavation activity.
  (i) Damage records.
  (ii) The number of underground locate requests received.
  (iii) Significant construction activities.
(4) Geologic conditions.
  (i) Frost areas.
  (ii) Earthquake zone (e.g., soil liquefaction areas).
  (iii) Known washout areas.
  (iv) Land subsidence areas.
(5) Operating pressure (e.g., maximum actual operating pressure).

(b) Local system knowledge can also be key to understanding what is happening in and to the system. For example, field personnel are probably the best source of information about areas prone to flooding or washouts, or local corrosion technicians may know where interference currents are possible. The operator should consider interviewing personnel most familiar with the facilities to determine valuable information that may not appear in routine maintenance documentation and to evaluate existing forms (electronic or paper) for gaps in documentation.

3.5 Documentation.

The operator should have a way to gather and retain information about the distribution system. The operator's procedures should be updated as necessary to ensure that the appropriate information is being gathered for future use.

Methods to document the physical components of the distribution system may include the following.

(a) Identifying relevant system components on maps.
(b) Maintaining electronic records.
(c) Maintaining hard copy files.
(d) Any combination of the above.

4 IDENTIFY THREATS

4.1 Primary threats.

The primary threats to a natural gas distribution system are as follows and are generally described in the instructions for the DOT Annual Report, PHMSA Form F7100-1.1.

(a) Corrosion.
(b) Natural forces.
(c) Excavation damage.
(d) Other outside force damage.
(e) Material or welds.
(f) Equipment failure.
(g) Incorrect operation.
(h) Other.

An operator may subdivide the primary threats into subcategories to assess the relevance of a threat. An operator should also consider threats that could degrade the system over time (see 3.3(d) above). Operators who have system materials other than those specifically shown in Table 4.1 should also consider those different materials and analyze them relative to the primary threats.

4.2 Identify threats.

(a) One possible method for identifying applicable threats to a system that may be used is answering appropriate questions such as those in Table 4.1 and making the determination of whether the threat exists throughout the system (General) or is limited to a certain geographic region or material (Local). Some threats may be insignificant, non-existent, or not applicable (NA). These questions may or may not be applicable to all facilities or groups of facilities in an operator's system.
(b) The questions in Table 4.1 are not intended to be all-inclusive. They are provided to help the operator understand conditions that may indicate the possible presence of a particular threat. Operators are encouraged to ask as many questions as they determine are needed to define or eliminate a threat.
(c) Before the presence of a threat can be verified as applicable to the operator's distribution system, the operator should have "knowledge of the distribution system" as described in Section 3. Threats may vary based on the makeup and location of the system. For example, a plastic system does not experience a corrosion threat, an aging cast iron system may be prone to leakage at joints, and systems located in high-growth areas may experience an increased threat of excavation damage.
(d) The applicability of threats to an operator's distribution system may be identified by reviewing relevant operating and maintenance records (e.g., incident and leak history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, one-call and excavation damage experience), considering knowledge of operating personnel, and evaluating relevant information. Operators may also use external sources of information, such as trade associations, other operators, manufacturers' recalls, PHMSA advisory bulletins, or other recommendations.

4.3 Sample threat identification method.

Attention can be focused on certain facilities or groups of facilities by first determining if one or more of the primary threats are causing a problem[2] on a distribution system. The nature and location of the problems should lead the operator in the direction to follow in determining threats to the system. Table 4.1 further breaks down the threats into subcategories.

[2] *Problem is what happens when a threat is realized. Examples may include the following.*
(a) Leak clusters, especially with a common cause or on a common material or component type.
(b) Previously identified hazardous (e.g., Grade 1) leak history or trend.
(c) Damage clusters due to a common cause.
(d) Areas where poor records result in frequent mis-marking.
(e) Known "frequent offender" excavators.
(f) Conditions related to current or past remedial activities.

<table>
<tr><th rowspan="2">Primary Threat</th><th rowspan="2">Threat Subcategories</th><th rowspan="2">Questions to Check Subcategory Applicability to System</th><th colspan="3">Extent of Threat</th></tr>
<tr><th>General</th><th>Local</th><th>NA</th></tr>
<tr><td rowspan="5">CORROSION</td><td>External corrosion:
bare steel pipe
(CP or no CP)</td><td>○ Does bare steel exist in the system?
○ Is the pipe cathodically protected?
○ Have corrosion leaks occurred?
○ Do exposed pipe inspections indicate external corrosion?
○ Are cathodic protection readings consistently adequate during annual monitoring?
○ Are there known sources of stray electrical currents in the area?</td><td></td><td></td><td></td></tr>
<tr><td>External corrosion:
cast iron pipe
(graphitization)</td><td>○ Does cast iron or ductile iron exist in the system?
○ Have fractures occurred in the pipe, other than those related to excavation activities?
○ Are the fractures limited to certain diameters of pipe?
○ Are there known sources of stray electrical currents in the area?
○ Do exposed pipe inspections indicate external corrosion?</td><td></td><td></td><td></td></tr>
<tr><td>External corrosion:
coated and wrapped steel pipe
(CP or no CP)</td><td>○ Does coated and wrapped steel exist in the system?
○ Is the pipe cathodically protected?
○ Have corrosion leaks occurred?
○ Are there known sources of stray electrical currents in the area?
○ Are cathodic protection readings consistently adequate during annual monitoring?
○ Do exposed pipe inspections indicate external corrosion?
○ Do exposed pipe inspections indicate coating deterioration?</td><td></td><td></td><td></td></tr>
<tr><td>Other metallic materials</td><td>○ Do other metallic materials exist in the system?
○ Is the pipe cathodically protected?
○ Have corrosion leaks occurred?</td><td></td><td></td><td></td></tr>
<tr><td>Internal corrosion</td><td>○ Does metallic pipe exist in the system?
○ Do piping inspections indicate internal corrosion?
○ Have internal corrosion leaks occurred?
○ Have liquids been found in your system?</td><td></td><td></td><td></td></tr>
</table>

Table 4.1 Continued

Primary Threat	Threat Subcategories	Questions to Check Subcategory Applicability to System	Extent of Threat		
			General	Local	NA
EXCAVATION DAMAGE (Continued)	Third Party (Continued)	○ Have leaks been experienced on the system where previous damage has occurred ○ Are there known areas of blasting or demolition activity? ○ Have leaks occurred due to blasting? ○ Do portions of the system exist in areas where excavation in the area of the pipeline would require the use of explosives?			
OTHER OUTSIDE FORCE DAMAGE	Vehicular	○ Are aboveground facilities being hit by vehicles? ○ Are aboveground facilities located near a roadway, driveway, or other location where they may be susceptible to vehicular damage? ○ Are susceptible aboveground facilities protected from vehicular damage?			
	Vandalism	○ Has damage or leakage been caused by malicious actions of unauthorized individuals? ○ Has gas theft occurred?			
	Fire/Explosion (primary)	○ Have there been instances of "Fire First" events (the origin of the fire is unrelated to the gas system subject to Parts 191 and 192)?			
	Leakage (previous damage)	○ Have significant numbers of previous damage cases been found? ○ Has leakage caused by previous damage occurred?			
	Blasting	○ Does the potential for blasting operations near gas facilities exist? ○ Are appropriate procedures in place? ○ Has blasting damage occurred?			
	Mechanical damage: > Steel pipe > Plastic pipe > Pipe components	○ Have failures due to mechanical damage been experienced, such as underground structures in contact with facilities?			
MATERIAL OR WELD	Manufacturing defects	○ Have manufacturing defects in pipe or non-pipe components been experienced?			

Table 4.1 Continued

Primary Threat	Threat Subcategories	Questions to Check Subcategory Applicability to System	Extent of Threat		
			General	Local	NA
MATERIAL OR WELD (Continued)	Materials/ Plastic	○ Do any of the following materials exist in the system? > Century Utility Products? > Low-ductile inner wall Aldyl A pipe manufactured by DuPont Company before 1973? > PE 3306?			
	Weld/Joint	○ Have failures in welds or other joints occurred?			
EQUIPMENT FAILURE	System equipment	○ Have failures been experienced due to leaking seals or gaskets? ○ Have regulator or control malfunctions been experienced? ○ Have valve leaks/failures occurred? ○ Have other gas carrying facilities malfunctioned?			
INCORRECT OPERATION	Inadequate procedures	○ Have failures been experienced due to inadequate procedures?			
	Inadequate safety practices	○ Have failures been experienced due to inadequate safety practices?			
	Failure to follow procedures	○ Have failures been experienced due to a failure to follow procedures?			
	Construction/ workmanship defects	○ Have failures been experienced due to workmanship defects?			
OTHER		○ Have failures been experienced due to other reasons?			

TABLE 4.1 - SAMPLE THREAT IDENTIFICATION METHOD

4.4 Handling Interactive Threats.

Piping systems may be coincidently subjected to several of the threats defined in Section 4. However, when two or more of the threats combine in such a way that causes an increase in the severity, likelihood, or consequence of a failure, then these are called *Interactive Threats*.

<u>Example 1:</u> An operator estimates a certain type of fitting to fail at a rate of 1 in 1,000 due to “Equipment Defects.” However, the operator has determined that the same fittings will fail at a much higher rate, and with a more severe mode of failure when additionally subjected to “Other Outside Forces” (e.g., soil erosion, settling) and much greater consequence.

<u>Example 2:</u> An operator estimates that a known type of material experiences 1 leak per mile due to material degradation. However, the operator has determined that the same material will experience a much higher leakage rate, with a more severe mode of failure, when additionally subjected to “Other Outside Forces” such as the following.

(a) Frost heave.
(b) Settling.

(c) Weather-related ground movement (e.g., downslope ground movement).
(d) Subsidence.
(e) Clay soil expansion or contraction due to moisture content.

As part of the threat evaluation process described in this section, it is important for operators to understand how threats might interact within their system. One method for evaluating the potentially interactive threats is to conduct a pairwise evaluation between each and every threat type (and sub-threat type if appropriate). The purpose of the evaluation is to identify if the interaction of any threat or sub-threat pair results in a greater risk due to their interaction than the sum of their individual risk. Each operator's approach to developing a matrix may be different based on historical threats and how they have been observed to potentially interact in different parts of its system.

Table 4.2 identifies an example pairwise evaluation as well as an example of how the evaluation can be used in an operator's risk evaluation. Each row in the table represents a threat pair. Four threats are represented in the table as A, B, C and D. The "Qualitative Interaction" column identifies the qualitative result of the evaluation, while the "Quantitative Interaction" column can be the result of an SME evaluation, or based on empirical data analysis, and illustrates how the threat interaction can be used within the operator's risk evaluation model. Once established, the "Qualitative Interaction" multiplier should be consistently applied.

Threat #1	**Threat #2**	**Qualitative Interaction**	**Quantitative Interaction**
Threat 'A'	Threat 'B'	None	Keep the individual risk for Threat 'A' and Threat 'B' as is
Threat 'A'	Threat 'C'	Minor	Multiply the risk for Threat 'A' and Threat 'C' by some value greater than 1
Threat 'A'	Threat 'D'	None	Keep the individual risk for Threat 'A' and Threat 'D' as is
Threat 'B'	Threat 'C'	Minor	Multiply the risk for Threat 'B' and Threat 'C' by some value greater than 1
Threat 'B'	Threat 'D'	None	Keep the individual risk for Threat 'B' and Threat 'D' as is
Threat 'C'	Threat 'D'	Significant	Multiply the risk for Threat 'C' and Threat 'D' by some value significantly greater than 1

TABLE 4.2 - SAMPLE PAIRWISE INTERACTIVE THREAT EVALUATION

5 EVALUATE AND RANK RISK

The following are some examples of ways to evaluate risk [3] to a distribution system from the applicable threats that are identified in Section 4. There may be other ways to analyze and rank risks to a distribution system. This guide material is not intended to rule out any valid approach selected by the operator.

5.1 General.

(a) Once the potential threats, including interactive threats, to a distribution system are identified, the operator should decide if additional risk management practices as discussed in Section 6 are appropriate. A risk evaluation can help determine if such actions are needed or not. The final outcome from any risk evaluation should be a relative risk ranking of the facilities (pipe or components) or group of facilities that experience problems in the operator's distribution system. After a preliminary evaluation of facilities for each applicable current, potential, and interactive threat, it may be determined that certain facilities or groups of facilities do not experience problems and no further action would be necessary at that time.

[3] *Risk is the product of the likelihood of a problem occurring and the consequences that could be caused by the problem if it occurs.*

(b) Each operator will need to choose or develop a method of risk evaluation. There are many approaches that can be taken and the operator has the option of which to choose, as long as the process determines the relative importance of each threat and results in a relative risk ranking. The risks can be ranked separately by threat and then merged into one relative risk ranking. The risk ranking criteria for likelihood and consequence may be different for certain threats, such as excavation damage. "Relative risk" does not necessarily indicate an absolute measure of risk; it only indicates a comparative value relative to other facilities or groups of facilities experiencing problems.

(c) One approach to risk evaluation is to group facilities by common traits and problems, which allows each group to be risk-ranked as a unit. The risk ranking is an analysis that assigns a relative risk value and may result in a recommendation for action. This two-tiered approach will be discussed in more detail in the remainder of this section. This approach is provided solely as an example; the operator has the option of using other approaches, or combination of approaches, as appropriate.

(d) The operator should keep in mind that the risk evaluation approach chosen is to be used in addition to other criteria such as operational requirements and engineering judgment. In addition, it is important to remember that because distribution systems vary widely, each operator will have different information available and may choose to assign different values during the risk ranking process. However, the numbers or values in the examples may be used if they are appropriate for the particular system. No two operators are likely to have the same results.

(e) The operator should determine whether adequate information exists to perform a risk evaluation. If it is determined that additional information or risk-ranking factors are needed to be able to discriminate between different parts of a distribution system, the operator may need to determine how the appropriate data can be obtained, or if it is readily obtainable. It is not intended that an exhaustive data search be conducted. Where appropriate, the operator should consider developing a method that would capture the relevant information during routine operations and maintenance activities in the future. In the interim, the operator might consider assigning higher values for selected risk-ranking factors where information is "unknown."

5.2 Information evaluation.

(a) Gathering knowledge about a distribution system happens routinely (see Section 3). For example, the leak surveyors document where they have surveyed and where they have encountered gas leak indications; however, they may be unaware of the cause of leaks found. Evaluating information from the leak survey, corrosion control measures, leak repair data, and other routine operation and maintenance activities can help the operator determine if the threat applies to its distribution system.

There are other advantages of information evaluation. Examples are as follows.

(1) Tracking and trending leaks, cathodic protection levels, third-party damage occurrences, and other problems related to the threat categories or subcategories relevant to the operator's system may assist the operator in prioritizing risks and help measure the effectiveness of any risk management practices implemented to address the identified threats.

(2) The operator may consider breaking down the knowledge of its distribution system based on existing records and other information it has in order to help focus on the risk evaluation and risk management actions. For example, an operator with multiple manufacturers and vintages of differing types of plastic pipe in its distribution system may be able to determine that only certain parts of its system may be at risk from a particular threat.

(3) Ratio of no-show tickets to total tickets received by the operator. A *no-show ticket* is one that was not responded to by the locators within the allowed time.
(4) Failure by notification center to accurately transmit tickets to the operator.
(5) Damages by cause, facility type (mains, services), and responsible party. Cause categories may include the following.
  (i) Excavator's failure to call.
  (ii) Excavator's failure to provide accurate ticket information (e.g., wrong address).
  (iii) Operator's failure to mark.
  (iv) Operator's failure to mark accurately.
  (v) Excavator's failure to wait required time for marking.
  (vi) Excavator's failure to protect marks.
  (vii) Excavator's failure to utilize precaution when excavating within the tolerance zone.
  (viii) Excavator's failure to properly support and protect facility.
(6) Leaks or failures on previously damaged pipe.
(7) Repairs implemented as a result of first / second / third-party damage prior to leak or failure.
(8) Excavation notices versus number of locates (not all notices will require an actual locate).
(9) Locates timely or untimely made.
(10) Negative callbacks timely or untimely made if state law, the one-call center, or another entity requires such calls.
(11) Mis-locates later identified.

(d) Other outside force damage.
(1) Leaks or failures caused, or repairs necessitated, by vandalism.
(2) Leaks or failures caused, or repairs necessitated, by vehicular damage.
(3) Instances of damage that is secondary to non-pipeline fire or explosion.
(4) Leaks or failures on previously damaged pipe.
(5) Leaks, failures, damage, or movement caused by blasting.
(6) Leaks, failures, damage, or movement caused by heavy vehicle traffic over or near pipelines.

(e) Material or welds.
(1) Pipe failures during pressure tests.
(2) Joint failures during pressure tests.
(3) In-service pipe or joint failures (not caused by outside force or excavation damage).
(4) Production joints rejected by an inspector other than the joiner.
(5) Joiners failing re-qualification.

(f) Equipment failure.
(1) Regulator failures.
(2) Relief valve failures.
(3) Seal, gasket or O-ring failures.
(4) Regulators or relief valves found with set points outside of acceptable range.
(5) Emergency valves found inoperable.
(6) SCADA failures, system upsets, or false readings.

(g) Incorrect operations.
(1) Service outages due to operator error.
(2) Odor tests finding insufficient odorant.
(3) Response times to leak or odor calls.
(4) Hazardous leaks make safe or repair times.

(h) Other.
Case-by-case determination.

8 PERIODIC EVALUATION AND IMPROVEMENT

Periodic review and evaluation of DIMP is an integral part of the process. This should include at least two activities. First, a review of the written plan content to ensure it remains accurate and appropriate. Second, the success and effectiveness of risk management techniques or practices or A/A actions adopted to respond to specific threats should be analyzed.

8.1 Review of the written plan.

(a) The plan should be periodically reviewed at an interval determined to be appropriate by the operator and updated on an as-needed basis. Consideration should be given to reviewing this plan on a frequency similar to that used for other operational plans and procedures. For example, operating and maintenance manuals and public awareness programs are required by regulation to be reviewed annually, so it may be convenient to schedule review of the written plan at the same time.

(b) The review should include verifying, and updating as needed, content such as any contact information contained in the plan, names or numbers of designated forms, information storage locations, action schedules, etc. This is also a good time to review experience with the plan and consider revising any parts that users have found confusing or difficult to implement.

(c) Another reasonable time for plan review and updating may be after a plan milestone has been achieved. For example, if a major pipe replacement program was being conducted under the DIMP, and that project has been completed, the plan may need modification to reflect that this work is no longer ongoing. This may also be a good time to determine whether there are other risks that should now be given higher priority.

(d) Other plan revisions may be appropriate if review of performance measures concludes that a change of approach is warranted, such as selection of a different performance measure, or of a different risk management technique or practice.

(e) The operator should maintain a record demonstrating that the plan review was performed even if no changes were made.

8.2 Review of effectiveness.

(a) The data collected for a performance measure should be periodically reviewed to determine if the risk management technique or practice (A/A action) implemented is effective. A DIMP should show that the risks it addresses are being managed effectively.

(b) During review, the data that supports the performance measure for a risk management technique or practice (A/A action) should be collected and analyzed. Analysis methods may range from simple side-by-side comparisons of before-and-after data to sophisticated statistical data processing. The analysis should examine whether the evidence indicates the practice or action is or is not managing the targeted risk. Decisions are then made on whether to continue, or discontinue, with the action, accelerate or decelerate its pace, modify how it is being implemented, or choose another action. It is not required that a review always find that a particular risk management technique or practice is either effective or ineffective. It is acceptable to conclude that it is too soon to tell, or that currently there is insufficient data to tell how well an action is working.

(c) The analysis should also examine if the performance measure selected is providing information useful in analyzing the impact of the practice or action. If the impact is unclear, consider including other data in the review, or selecting a different performance measure.

(d) The frequency of review may depend on the time frame within which the operator anticipates that the A/A action will produce meaningful results. For example, one construction season may be enough to assess if additional damage prevention activities are noticeably reducing the frequency of dig-ins. On the other hand, it may take years to determine if changes in corrosion control practices are having an impact. It is recommended that the operator establish a review period appropriate for the performance measure. The interval should not exceed five years for any particular performance measure for consistency with the maximum allowed interval for complete program reevaluation.

9 REPORT RESULTS

Except for small LPG operators, four performance measures are required by §192.1007(g) to be reported to PHMSA on the operator's annual report and to the state, as applicable. State regulations may contain additional reporting requirements. The operator should ensure that the information needed to complete those reports is being collected and is available when needed.

5 ESTABLISHING SAFE GAS CONDITIONS AT THE WORK SITE

5.1 *Standard procedures*.
Established standard procedures should be used for cutting and welding, venting of gas leakage, and maintaining safe gas conditions during the progress of the work.

5.2 *Pressure buildup behind end closures*.
A positive method should be provided for preventing pressure buildup against temporary or unbraced end closures. Otherwise, end closures that are to be operated under pressure should be braced or anchored.

5.3 *Electrical grounding*.
Bonding cables, grounding rods, or grounding mats should be used to minimize hazards from electricity.

6 RETURN OF SHUTDOWN SECTION TO OPERATION

6.1 *Supervisor's determination*.
The person in charge should determine when the facility is ready to return to service.

6.2 *Standard procedures.*
(a) Established standard procedures (modified or supplemented, as appropriate) should be followed to purge, repressure, and return all facilities to normal operation.
(b) These procedures should consider the potential for unknown hazards and include evacuation of personnel from excavations until all conditions are determined to be safe.

6.3 *Flow rates*.
Flow rates should be carefully controlled during repressuring, and pressures should be monitored until normal operations have been established.

6.4 *Return to normal settings*.
Pressure limiting stations, district regulator stations, relief valves, automatic valves, and other control equipment should be returned to their normal settings.

GUIDE MATERIAL APPENDIX G-192-13

(See guide material under §§192.103,192.183, 192.199, 192.203, 192.317, 192.321, 192.327, 192.353, 192.355, 192.361, 192.367, 192.613, 192.614, 192.707, and Guide Material Appendix G-192-6)

CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

1 INTRODUCTION

This Guide Material Appendix is intended as an aid in minimizing the possibility of damage to pipelines by outside force.

2 DESIGN

2.1 Selecting pipe locations.

(a) To provide better control over future construction activities, consideration should be given to installing facilities in private rights-of-way.
(b) When distribution facilities are to be installed in new areas, consideration should be given to developing a plan, in conjunction with other utilities, for assigning a standard location to each utility.
(c) Where practicable, facilities in a street should be installed at a constant distance from the property line. Diagonal installations and installations which "wander" in the street or right-of-way should be avoided. Where the street configuration permits, facilities should be installed in straight lines with right-angle corners at turns. Where practicable, service lines should be installed in a straight line from the main to the meter location.
(d) Where it is economically feasible, parallel main installations on each side of a street should be considered to avoid crossing the street with multiple service lines.
(e) Protective sleeves or bridging should be considered for PE piping in addition to providing adequate backfill and compaction to reduce excessive bending and shear stresses. Protective sleeves are designed to mitigate the stresses imposed on the PE pipe due to earth settlement where other utility crossings are made beneath PE piping. Without bridging or a protective sleeve, earth settlement beneath the existing PE piping may cause a downward bow of the PE piping resulting in stress concentrations at the edges of the excavation area. For protective sleeves, see guide material under §192.367.
(f) The installation of facilities should be avoided in areas where storm sewer lines or catch basins are likely to be installed.
(g) The probable pattern of future land use should be considered in selecting the route for new pipelines.

2.2 Cover.

The cover requirements of §192.327 are minimums. Additional cover should be provided where the potential for damage by outside forces is greater than normal. Consideration should be given to the following.

(a) Agricultural land where deep-plowing equipment or sub-pan breakers are used.
(b) Agricultural land where the grade may be changed to permit irrigation or drainage.
(c) Drainage ditch crossings. Consideration may also be given to alternates, such as casing or a protective concrete or steel slab.
(d) Other utility crossings. The new gas facilities should be installed under the existing facilities, unless adequate cover can be provided or casing, bridging, or other protection is used.
(e) Locations where erosion due to wind, water, or vehicular activity may affect the grade. Riprap, paving, or some other means of protection may be used in lieu of additional cover.
(f) Street locations where future street work is a possibility.
(g) Locations where frost, drought, and heat might affect the pipeline.

(h) Water-body crossings where storm events, scouring, erosion, and dredging may alter the water bottom and change the depth of cover or expose the pipeline.

2.3 Earth Movement.

(a) Identify areas surrounding the pipeline that might be prone to earth movement and could result in excessive strain on the pipeline. Earth movement might include slope instability, landslides, subsidence, frost heave, soil settlement, erosion, or earthquakes.

(b) Consider performing geological studies to determine mitigative measures that might be employed to avoid or minimize negative impact of earth movement on the pipeline. Measures might include ensuring drainage of water from the pipeline trench, ensuring drainage of surface water off of the pipeline right-of-way, or stabilizing earth slopes by building retaining walls or installing sheet piling.

2.4 Landfills and unstable soil.

(a) Special consideration should be given when placing pipelines over landfill areas where the supporting fill might decompose. Mitigation measures include extra excavation and soil replacement or additional pipe support, such as slabs or casings.

(b) Long-wall or other mining underneath a pipeline might also lead to pipeline undermining or lack of support. Additional pipeline thickness, support bridging or slabs, or casings are all methods for consideration to mitigate these conditions.

(c) Areas subject to salt mining or sinkholes also deserve special consideration and might warrant one or more of the above solutions.

2.5 Navigable waterways.

(a) Where facilities will be installed in navigable waterways, the following should be considered.
  - (1) Dynamic interaction between the water and bottom.
  - (2) Flotation.
  - (3) Scouring.
  - (4) Erosion.
  - (5) Impacts of major storms.
  - (6) Potential dredging or anchoring activities.

(b) The use of models, such as hydrologic or land mass movement, might be beneficial.

(c) For information about work in harbors, see the National Research Council report, “Improving the Safety of Marine Pipelines” (1994), available online from National Academies Press (NAP) at www.nap.edu/read/2347.

3 MARKERS

In addition to the markers required by §192.707, consideration should be given to the following.

3.1 General.

(a) Installing line markers when a main, transmission line, or gathering line crosses or lies in close proximity to an area that, in the operator's judgment, is likely for excavation or damage. Typical examples include the following.
  - (1) Drainage areas, such as flood-prone watercourses.
  - (2) Irrigation ditches and canals subject to periodic excavations for cleaning out or deepening.
  - (3) Drainage ditches subject to periodic grading, including those along roads.
  - (4) Agricultural areas in which deep plowing or deep-pan breakers are employed.
  - (5) Active drilling or mining areas.
  - (6) Waterways or bodies of water subject to dredging or shipping activities.
  - (7) Industrial or plant areas where excavating, earth moving, and heavy equipment operating activities are routine.

(b) If multiple pipeline facilities are within the same right-of-way or in the same area, each operator should mark its facilities in a way to eliminate confusion.

(c) When line markers cannot be placed directly over a pipeline due to lack of support, obstructions, or need to facilitate maintenance, the markers can be offset from a pipeline facility. Markers may include language such as "in the vicinity" or "in proximity of," but should not include specific distances.

3.2 Transmission lines or gathering lines.

(a) Installing markers at designated locations along the right-of-way, where practical, and wherever the party exerting control over the surface use of the land will permit such installations. Possible locations for line marker placement include the following.
   (1) Fence lines.
   (2) Angle points (i.e., bends and changes in pipeline direction).
   (3) Lateral take-off points.
   (4) Stream crossings (including bridges).
   (5) Where necessary to identify pipeline locations for patrols and leak surveys.
   (6) Where necessary for visibility of line markers in both directions.

(b) Using other methods of indicating the presence of the line where the use of conventional markers is not feasible, such as stenciled markers, cast-monument plaques, signs, or devices flush mounted in curbs, sidewalks, streets, building facades, or other appropriate locations.

(c) Installing temporary markers in areas of known heavy construction activity during the period that construction is in progress near existing or newly installed facilities, whether energized or not, particularly along highways, strip mines, and major excavations.

3.3 Distribution lines.

(a) While markers are not normally practical for distribution systems, indicating the presence of the line where special problems exist. See 3.2(b) above for alternate methods of marking.

(b) Installing temporary markers near existing or newly installed facilities, whether energized or not, particularly in areas of construction activity during the period that construction is in progress.

3.4 Underwater pipeline.

The use of buoys, poles, PVC markers, or other forms of temporary marking suitable for underwater pipelines. The type of marker chosen may be influenced by the depth of water, the types of vessels normally navigating the area, and other characteristics of the body of water.

4 MINING ACTIVITIES

(a) An operator should consider the effects of mining activities on pipeline facilities. The ground subsidence and soil overburden can cause significant stresses in pipelines.

(b) Long-wall mining is of special concern to pipeline operators. Long-wall mining involves complete removal of a coal seam, which is typically 200 to 1,500 feet underground. The roof of the mine collapses, and the collapse propagates to the surface.

(c) Operators with pipelines in areas of mining activity should consider the following actions.
   (1) Contact the mine operator to obtain the depth of coal, mined height, width of the seam, location and angle at which the activity passes under the pipeline, estimated schedule of mining activities, and previous subsidence profiles for other mines in the area.
   (2) Review the material properties of the pipe and associated valves and fittings, such as specification, rating or grade, wall thickness, SMYS, toughness, and seam and joint characteristics.
   (3) Perform subsidence calculations to predict the effect on the pipeline. One method of predicting subsidence was developed by the National Coal Board (NCB) and is reported in the "Subsidence Engineers' Handbook."
   (4) Reduce the operating pressure, or remove the pipeline from service, if warranted by predicted stress levels.
   (5) Expose the pipeline to limit overburden stress.
   (6) Monitor subsidence and strain levels. A reference for monitoring subsidence is PRCI L51574, "Non-Conventional Means for Monitoring Pipelines in Areas of Soil Subsidence or Soil Movement."

5 RECORDS

The location of facilities should be accurately mapped or otherwise recorded. The operator should ensure that maps or records used for locating facilities are updated whenever any changes are made.

6 DAMAGE PREVENTION CONSIDERATIONS

See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies. For damage prevention programs, see guide material under §192.614.

7 VEHICULAR DAMAGE

When determining a safe distance between an aboveground pipeline and vehicular traffic, consideration should be given to relevant factors, including the following.

(a) Type of public road (e.g., residential, federal or state highway, limited access highway).
(b) Type of driveway (e.g., residential, commercial, industrial).
(c) Type of off-road activity (e.g., four-wheeling, snowmobiling).
(d) Speed limit.
(e) Direction of traffic.
(f) Terrain.
(g) Natural or other barriers.
(h) Weather-related road conditions (e.g., ice, snow, snow removal).

8 OTHER

Consideration should be given to the following.

(a) Special precautions to protect buried control lines. See guide material under §192.199.
(b) Installing small-diameter, service line taps off large-diameter pipe so that the top of the tee is lower than the top of the pipe.
(c) The use of colored pipe wrap or coating so that the content of a pipe is readily evident. This coloring should conform to American National Standards where applicable.
(d) Where a plastic pipeline is installed in a common trench with electric underground lines, the need for additional clearance to prevent damage to the gas line from heating or a fault in the power line.
(e) Where future excavation (including grading) is likely, providing suitable means of warning (e.g., warning tape, marker paint, flags, temporary markers).
(f) For aboveground facilities, the potential for damage due to vandalism or other causes. Where unusual hazards may reasonably be expected, precaution should be taken to guard against them, such as guards, locks, protective barriers, or even an alternative or underground location.
(g) Responding to requests from third-party designers or planners for information regarding location of buried facilities. Such responses may include the following.
    (1) Providing maps.
    (2) Holding meetings.
    (3) Locating facilities in the field. See 2.7 of the guide material under §192.614.

    Recipients of such information should be reminded that notice of intent to excavate must still be provided in accordance with state or local regulations.

GUIDE MATERIAL APPENDIX G-192-21

(See guide material under §§191.1 and 192.1)

OCCUPATIONAL SAFETY AND HEALTH ADMINISTRATION LETTERS

1 SCOPE

This appendix includes letters from the Occupational Safety and Health Administration (OSHA) regarding application of their standards to working conditions that are regulated by PHMSA-OPS.

2 LETTERS

The following letters are assembled here for reference:

- OSHA letter to AGA dated April 8, 1999 re: Respiratory Protection — Exhibit 1
- OSHA letter to AGA dated May 25, 1994 re: Confined Space — Exhibit 2
- OSHA letter to AGA dated October 30, 1992 re: Process Safety Management — Exhibit 3
- OSHA letter to AGA dated July 19, 1990 re: Excavation Standards — Exhibit 4

U.S. Department of Labor

Occupational Safety and Health Administration
Washington, D.C. 20210

Reply to the Attention of: DCP/OHCA/CM

APR 8 1999

Mr. Kevin Belford, Esq.
General Counsel
American Gas Association
1515 Wilson Boulevard
Arlington, Virginia 22209

Dear Mr. Belford:

This letter is in response to several inquiries submitted to the Occupational Safety and Health Administration (OSHA) from pipeline owners and operators: Gordon Murdock of Questar, Greg Janson of Southwest Gas Corporation, and Stephen M. Sablack of Sempra Energy, as to whether OSHA is preempted from enforcing its recently revised Respiratory Protection Standard located at 29 CFR 1910.134 by regulations issued by the Department of Transportation's Office of Pipeline Safety (OPS).

Section 4(b)(1) of the Occupational Safety and Health Act, 29 U.S.C. § 653(b)(1), precludes OSHA from applying its standards to working conditions that are regulated by other federal agencies. In order for a working condition to qualify for the exemption, the other federal agency must have statutory authority to regulate the health and safety of working conditions of employees and must exercise that authority by standards or regulations having the force and effect of law. Section 4(b)(1) does not create an industry-wide exemption. It only exempts specific "working conditions" that are subject to the worker safety or health regulations of other agencies.

OPS has promulgated regulations which address the provision and use of breathing apparatus to protect workers against hazardous air contaminants. 49 CFR 192.605 provides, *inter alia,* that each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. Section 192.605(b)(9) provides that the manual must include procedures for "[t]aking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and a rescue harness and line." Additionally, OPS regulations provide that each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. 49 CFR 192.615(a). At a minimum, the procedures must provide for the availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency. 49 CFR 192.615(a)(4). Section 192.615(b)(1) requires each operator to furnish the latest emergency procedure to its supervisors who are responsible for emergency action. Section 192.615(b)(2) requires each operator to train appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and to verify that the training is effective.

In a telephone conference on January 13, between OSHA and Solicitor of Labor staff and Office of Pipeline Safety representatives, OPS indicated that the regulations indeed constitute the agency's intent to regulate the use of respirators in operations, maintenance, and emergencies. OSHA's respirator standard addresses the same working conditions as the OPS regulations listed above. The OSHA standard requires employers whose workplaces contain actual or potential hazardous concentrations of air contaminants to establish a respiratory protection program, which must include the provision of appropriate respirators for the hazard involved and procedures for the proper use of those respirators. The OPS regulations require the provision and use of emergency equipment, including respirators, to protect against unsafe accumulations of vapors and gases in pipeline trenches. The OPS regulations thus require protection against the same hazard – unsafe concentrations of air contaminants – addressed by the OSHA standard. OSHA concludes that it is therefore preempted, under § 4(b)(1), from enforcing the Respiratory Protection Standard against employers subject to the OPS regulations, namely, pipeline owners and operators. However, OSHA is not preempted from enforcing the standard as to contractors, or other entities not covered by the requirements of 49 CFR Part 192. *Texas Eastern Transmission Corp. and Sinapp Company - Staten Island, Inc.*, 3 BNA OSHC 1601, 1605 (Nos. 4091 and 4078, 1975). OSHA has conferred with representatives of OPS responsible for enforcing the OPS regulations, and they have informed OSHA that they concur in these conclusions.

Please feel free to distribute this letter to any of your members with an interest in this subject. We will make our field offices aware of this interpretation through distribution of this letter, as well. With respect to your members in any of the 23 States with federally-approved state OSHA plans, we should note that State Plans operate under authority of State rather than Federal law, and the restrictions in section 4(b)(1) do not necessarily apply. OSHA will furnish an information copy of this letter to each State plan State and encourage them to consider a similar policy interpretation, but since coverage provisions may differ somewhat under the laws in individual States, your members in State plan States may wish to contact the State plan agency directly.

Sincerely,

Richard E. Fairfax

Richard E. Fairfax
Director
Directorate of Compliance Programs

cc:
Mr. Gordon Murdock, Questar
Mr. Stephen M. Sablack, Sempra Energy
Mr. Greg F. Janson, Southwest Gas Corporation
Mr. Terry Boss, Interstate Natural Gas Association of America

U.S. Department of Labor

Assistant Secretary for
Occupational Safety and Health
Washington, D.C. 20210

MAY 25 1994

David J. Muchow, Esq.
General Counsel and
Corporate Secretary
American Gas Association
1515 Wilson Boulevard
Arlington, VA 22209

Dear Mr. Muchow:

This letter is in response to the American Gas Association's (A.G.A) Request For Clarification, Or In The Alternative, Petition For Administrative Stay, dated March 5, 1993. A.G.A. has requested that OSHA clarify that, in light of the preemption provision in Section 4(b)(1) of the Occupational Safety and Health Act, the final rule on Permit-Required Confined Spaces (PRCS), which requires employers to implement safety precautions prior to and during entry into confined spaces whenever serious atmospheric, mechanical or other types of hazards are present, does not apply to gas utility vaults. The Department of Transportation's Office of Pipeline Safety (OPS) has issued regulations covering natural gas distribution and transmission facilities, including vaults and related spaces. 49 C.F.R. §191, §192 (1991).

At a meeting on April 8, 1993 between OSHA and Solicitor of Labor staff and A.G.A. representatives concerning the March 5 submission, A.G.A. engineers stated that the presence of gas was the only hazard ordinarily encountered by employees in conducting inspections and performing normal maintenance work in vaults. A.G.A. expressed concern that broad application of the PRCS standard to vaults would require significant changes in its members' operating procedures, which conform to OPS procedures for minimizing the hazards of gas in such spaces. According to A.G.A., this would subject gas utility companies to conflicting federal requirements and could lead to disruption of services.

As A.G.A. has pointed out, section 4(b)(1) of the OSH Act, 29 U.S.C. §653(b)(1) (1988), precludes OSHA from applying its standards to working conditions that are regulated by other federal agencies. The phrase "working conditions" encompasses both a worker's surroundings and the hazards incident to his work. See, Columbia Gas of Pennsylvania v. Marshall, 636 F.2d 913 (3d Cir. 1980); Southern Railway Co. v. OSHRC, 539 F.2d 335 (4th Cir. 1976); Southern Pac. Transp. Co. v. Usery, 539 F.2d 386, 390 (5th Cir. 1976). See also In re Inspection of Norfolk Dredging Co., 783 F.2d 1526, 1530-32 (11th Cir. 1986). Thus, an OSHA standard does not apply to the extent that another federal agency prescribes or enforces standards addressing the same general working conditions.

Current OPS regulations contain requirements for adequately ventilating large vaults and for providing a means for testing the atmospheres of sealed vaults prior to entry, 49 C.F.R. §192.187 (1991); for designing and locating vaults to minimize the entrance of water, 49 C.F.R. §§192.85, 189 (1991); for periodically inspecting vault equipment and for repairing leaking or faulty equipment, 49 C.F.R. §192.749 (1991), and for minimizing the danger of fire, or explosion in any structure or area in which gas might be present, 49 C.F.R. §192.751 (1991). Operators must also report to OPS any incident involving a death or serious injury associated with the release of gas from a pipeline. 49 C.F.R. §191.5 (1991). While these provisions are primarily directed to the hazards of fire and explosion, they appear sufficiently related to the general problem of hazardous vault atmospheres to preempt all OSHA regulation of such hazards under the PRCS, including fire, explosions, toxicity and oxygen deficiency. Southern Pac., 539 F.2d at 391 (noting that comprehensive Federal Railroad Administration treatment of the general problem of railroad fire protection would displace all OSHA regulation on fire protection even if the FRA regulations differed from OSHA's).

Furthermore, OSHA recognizes that the application of the PRCS standard to atmospheric hazards in vaults, even if limited to hazards such as toxicity or oxygen deficiency, could impair a pipeline operator's ability to respond quickly to protect the public safety in a gas emergency, a result in apparent conflict with OPS's overall scheme. See 49 C.F.R. §192.615, §192.711 (1991). Cf. Southern Pac., 539 F.2d at 392 (dominant agency regulations may displace OSHA regulations by articulating a formal position that a given working condition should go unregulated or that certain regulations - and no others - should apply to a defined subject). For these reasons, OSHA does not intend to enforce the PRCS standard in vaults to the extent that such enforcement would be based on hazards that relate to gas or other hazards that are addressed by DOT/OPS regulations.

However, enforcement of the PRCS standard in vaults is not entirely preempted. Because the OPS regulatory scheme primarily relates to the hazards of gas in vaults, the more comprehensive PRCS standard may apply to these spaces to the extent that hazards other than those related to gas are involved. Norfolk Dredging Co., 783 F.2d at 1531; Southern Pac., 539 F.2d at 391. As an example, if a vault contains no gas but employees encounter other, unusual hazards which could impair the entrant's ability to escape from the space, some of the procedures in the PRCS standard may apply. Based on A.G.A.'s representation that such other hazards are not reasonably predictable in its vaults, A.G.A.'s members need not develop a permit-required confined space program to address such hazards in advance. If such unusual hazards are encountered, they should be dealt with by following sound industrial hygiene and safety procedures, including the procedures set forth in §1910.146(d) that are relevant in light of the particular hazards involved. The discovery of such hazards initially by workers, where the employer could not reasonably have known of the existence of the hazard, will not constitute a violation of the OSH Act or the PRCS standard.

This interpretation addresses the concerns raised in A.G.A.'s March 5, 1993 submission and discussed during the meeting of April 8, 1993 and is consistent with the agency's prior enforcement policy. Based upon the information A.G.A. has provided, OSHA expects that the PRCS standard would apply only in unusual circumstances in which hazards not normally encountered in day-to-day operations are present.

The policy stated in this letter applies to employers and vaults regulated by current OPS regulations. Should relevant OPS regulations be repealed or modified, it would be necessary for OSHA to reconsider its position. However, as long as current OPS regulations remain in effect, OSHA will not apply the PRCS standard to working conditions addressed by DOT/OPS regulations in vaults.

Sincerely,

Joseph A. Dear

Joseph A. Dear
Assistant Secretary

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U.S. Department of Labor

Assistant Secretary for
Occupational Safety and Health
Washington, D.C. 20210

OCT 30 1992

1992
PRESIDENT'S OFFICE

Mr. Michael Baly, III
President
American Gas Association
1515 Wilson Boulevard
Arlington, Virginia 22209

Dear Mr. Baly:

This is in response to your letter of August 18, requesting a decision from the Occupational Safety and Health Administration (OSHA) on whether our final rule on Process Safety Management (PSM) applies to natural gas distribution and transmission facilities.

It has long been OSHA's position that the agency cannot issue a Section 4(b)(1) exemption for an entire industry. Additionally, both the Occupational Safety and Health Review Commission (OSHRC) and the courts have rejected the industrywide exemption concept. However, this does not mean that certain specific work operations may not be determined to be outside OSHA jurisdiction, given the proper circumstances.

On October 1, OSHA staff met with their counterparts from the Department of Transportation's Office of Pipeline Safety (OPS) to discuss OPS regulations vis-a-vis PSM. OPS staff gave generously of both their time and expertise. They outlined their current regulations, as well as proposals which are in various stages of the rulemaking process.

As a result of that meeting, and following our review of OPS regulations, OSHA has concluded that current OPS regulations address the hazards of fire and explosion in the gas distribution and transmission process. Accordingly, OSHA has determined that the agency is precluded from enforcing the PSM rule over the working conditions associated with those hazards.

Today's interpretation addresses only the applicability of the PSM standard to the gas transmission or distribution process as noted above; it does not address the applicability of OSHA standards other than PSM, or the applicability of OSHA requirements to operations other than those described above. For example, natural gas processing facilities, in our view, would be subject to OSHA coverage notwithstanding today's interpretation. Finally, it should be noted that employers not subject to particular OPS requirements remain fully subject to OSHA requirements including the PSM standard.

Should current OPS requirements regarding hazards in gas transmission or distribution operations be repealed or modified by Congress or by OPS, it would be necessary for OSHA to revisit this issue. However, as long as current OPS rules and requirements remain in effect, OSHA will not seek to enforce the PSM standard against employers who are subject to OPS requirements with respect to fire or explosion hazards in connection with gas transmission or distribution.

Thank you for bringing the concerns of your membership to our attention. If we can be of any further assistance, please do not hesitate to contact us.

Sincerely,

Dorothy L. Strunk

Dorothy L. Strunk
Acting Assistant Secretary

U.S. Department of Labor

Assistant Secretary for
Occupational Safety and Health
Washington, D.C. 20210

JUL 19 1990

RECEIVED
JUL 19 1990
CLERK OF THE UNITED
STATES COURT OF APPEALS

Mr. David L. Muchow
General Counsel
and Corporate Secretary
American Gas Association
1515 Wilson Boulevard
Arlington, Virginia 22209

Re: Preemption of Certain OSHA Excavation Standards by DOT Office of Pipeline Safety Standards

Dear Mr. Muchow:

The Occupational Safety and Health Administration's (OSHA) excavation standard issued on October 31, 1989, generally applies to all employers who engage in excavation work or who have employees exposed to hazards arising out of such work. During the rulemaking proceeding leading to the standard's issuance, the American Gas Association (AGA) contended that certain requirements should not apply to employers engaged in natural gas transmission and distribution. The AGA pointed out that such employers must comply with safety standards issued by the Department of Transportation's (DOT) Office of Pipeline Safety (OPS), and that certain OPS standards addressed the same working conditions as did specific subsections of OSHA's proposed standard. The AGA's comments particularly addressed the following two subsections of the OSHA standard:

> 29 CFR § 1926.651(g)(1)(iii):
>
> Adequate precaution shall be taken such as providing ventilation, to prevent employee exposure to an atmosphere containing a concentration of a flammable gas in excess of 20 percent of the lower flammable limit of the gas.
>
> 29 CFR § 1926.651(g)(2)(i):
>
> Emergency rescue equipment, such as breathing apparatus, a safety harness and line, or a basket stretcher, shall be readily available where hazardous atmospheric conditions exist or may reasonably be expected to develop during work in an excavation. This equipment shall be attended when in use.

In response to the gas industry's continuing concern over these two subsections, we have carefully considered whether existing OPS standards preempt OSHA from enforcing them against employers who are subject to the OPS standards. For the following reasons, we have determined that such OSHA enforcement is preempted.

OSHA is the agency primarily responsible for assuring safe and healthful working conditions in American workplaces. However, Congress has delegated to other Federal agencies the responsibility for regulating particular workplace health and safety matters. Where other agencies have such authority, their regulations have priority over OSHA's, and OSHA standards do not apply to working conditions that the other Federal agencies have regulated. This conclusion follows from section 4(b)(1) of the Occupational Safety and Health Act (OSH Act), which provides that the OSH Act does not apply to working conditions with respect to which other Federal agencies "exercise statutory authority to prescribe or enforce standards or regulations affecting occupational safety or health."

The Natural Gas Pipeline Safety Act gives DOT the responsibility for issuing safety standards governing the transportation of natural gas through pipelines. OPS regulations issued under this mandate are found at 49 CFR Parts 191, 192, and 193. Certain of these OPS regulations address the maintenance and repair of gas pipelines, work that often requires employees to work in excavations opened for the purpose of gaining access to the lines. To the extent that the OPS regulations address the same occupational safety and health conditions addressed by the OSHA excavation standard, section 4(b)(1) precludes OSHA's enforcement of its standard.

Subsection 1926.651(g)(1)(iii) of the OSHA excavation standard requires that the concentration of flammable gas be maintained below 20 percent of the lower explosive limit. This provision is intended to prevent fires and explosions that could result from explosive concentrations of flammable gases. The OPS regulation at 49 CFR § 192.751 addresses the same safety problem, requiring pipeline operators 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." This OPS regulation therefore preempts enforcement of subsection 1926.651(g)(1)(iii) against employers who are subject to the DOT standard.

Subsection 1926.651(g)(2)(i) of the OSHA standard requires that emergency rescue equipment be provided where hazardous atmospheric conditions exist or may reasonably be expected to develop in an excavation. As the AGA has pointed out, OPS has adopted a standard requiring that precautions be taken against anticipated emergencies that can arise when a gas pipeline is being repaired. The OPS standard at 49 CFR § 192.615 requires gas pipeline operators to anticipate emergencies and develop plans to meet them. Since both the OSHA and OPS standards require pipeline operators to anticipate potential emergencies and implement precautions before such emergencies occur, OSHA concludes that the OPS standard addresses the same working condition as subsection 1926.651(g)(2)(i) and therefore preempts enforcement of that subsection against employers subject to the OPS standard.

In concluding that these two OSHA subsections cannot be enforced against employers subject to the DOT pipeline safety standards, OSHA has not attempted to determine whether the OPS standards offer appropriate protection against the hazards involved. It is sufficient that they address the same conditions addressed by the OSHA subsections. Should DOT repeal or amend the standards discussed earlier, it would be necessary for OSHA to reevaluate this issue. However, as long as the present DOT standards at 49 CFR §§ 192.751 and 192.615 remain in effect, OSHA will not attempt to enforce 29 CFR §§ 1926.651(g)(1)(iii) and 651(g)(2)(i) against employers who are subject to the OPS standards.

Finally, this letter does not affect potential OSHA enforcement of other provisions of the excavation standard. Nor does this letter affect the right of individual gas companies to contest jurisdiction on grounds of preemption of other provisions of the excavation standard.

Sincerely,

Gerard F. Scannell
Assistant Secretary

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