

May 16, 2024

Dear *Guide* Purchaser,

Enclosed is ANSI/GPTC Z380.1, *Guide for Gas Transmission, Distribution, and Gathering Piping Systems*, 2022 Edition, which includes Addenda 1, 2, 3, and 4.

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 4, May 2024

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 were no Federal Regulation update(s) for this period. 19 GPTC transactions affected 22 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 6 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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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.

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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

Engineers (ASME), the ASME initiated discussions with the DOT/OPS, in an effort to establish the future role of the B31.8 Code Committee with respect to pipeline safety. As a result of those discussions, the ASME decided to form the ASME Gas Piping Standards Committee. The title of the Committee was changed to the Gas Piping Technology Committee (GPTC) on September 20, 1982.

The first edition of the "Guide for Gas Transmission and Distribution Piping Systems" was published on December 15, 1970. It was essentially a compilation of the Federal Safety Standards and the then current ANSI B31.8 Code material that was relevant to the Part 192 requirements. Subsequent editions and addenda to the "Guide" had "how to" Guide Material directly following each of the standards of 49 CFR Part 192, and numerous guide appendices. Part 191 was subsequently added to the 1995 Edition of the Guide.

On October 18, 1989, the GPTC voted to transfer its affiliation from ASME to the American Gas Association (AGA). The transfer of copyright for the Guide from ASME to AGA was effective on April 10, 1990 and the AGA was designated the committee Secretariat. The first edition of the Guide published by AGA, as the new copyright holder/Secretariat, was in November 1990 and was designated the 1990-91 Edition. The GPTC sought ANSI approval of their procedures and was approved as an Accredited Standards Committee GPTC Z380 on January 30, 1992. The 1990 Edition of the Guide was approved as ANSI GPTC Z380.1 on December 2, 1992.

The current 2022 Edition supersedes all previous editions and respective addenda as follows: *Guide for Gas Transmission and Distribution Piping Systems* 1970, 1973, 1976, 1980, 1983, 1986 and then ANSI/GPTC Z380.1-1990, *Guide for Gas Transmission and Distribution Piping Systems*, followed by 1995, 1998, 2003, 2009, and 2012. The title of the Guide was revised for the 2015 Edition to "Guide for Gas Transmission, Distribution, and Gathering Piping Systems."

FOREWORD

The primary purpose of GPTC Z380.1 "Guide for Gas Transmission, Distribution, and Gathering Piping Systems" (Guide) is to provide assistance to the operator in complying with the intent of the Code of Federal Regulations (CFR) in the performance requirements contained in the Transportation of Natural and Other Gas by Pipelines, Title 49 Subchapter D-Pipeline Safety: Part 191 - Annual Reports, Incident Reports, and Safety-Related Condition Reports; and Part 192 - Minimum Federal Safety Standards (typically referred to hereinafter as the "Regulations").

The Guide includes the Minimum Federal Safety Standards together with the design recommendations, material reference, and recommended practices of the GPTC. The function of the GPTC's guide material is to provide "how to" supplementary recommendations related to the Minimum Federal Safety Standards. The Committee continuously works to pinpoint areas where more guide material could be provided in support of the Minimum Federal Safety Standards and related Regulations.

The Guide includes the Federal Regulations plus the GPTC's guide material for both Parts 191 and 192. The Guide is published in loose-leaf and electronic formats. As changes occur to the Regulations and related guide material, 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. A new edition, incorporating all previous addenda that have been published, is usually issued every three years.

The historical reconstruction of the Regulations is available in AGA X69804, "Historical Collection of Natural Gas Pipeline Safety Regulations." It includes the original version of Parts 191 and 192 and all their amendments through Amdts. 191-15 and 192-93 (published September 15, 2003). The Federal Register preamble to the amendments is included as well. This collection of all earlier amendments has been established as a readily accessible reference to supplement the Guide or to aid research activity. However, considering the electronic availability of amendments starting in 2004, refer to the Federal Register web site for later amendments.

The format of the Guide includes the title of each numbered section of the Regulations and is followed by the effective date of the latest amendment activity or effective date of the original version if no amendment has been issued. The Regulation is followed by a list of amendment or control numbers for the respective section and the applicable guide material as developed by the Committee.

The Guide is maintained using the continuous maintenance process. Proposals to revise any guide material may be submitted to the Committee at any time. A *Form for Proposals on ANSI GPTC Z380.1* is provided at the end of the Guide and may also be obtained on the GPTC website at www.aga.org/gptc. Use that form to describe and justify the proposal and submit it to: GPTC Secretary, American Gas Association, 400 N. Capitol Street, NW, Washington, D.C. 20001 (or email GPTC@aga.org). A separate completed form should be submitted for each proposed revision.

Requests for interpretations, proposed additions, and revisions to the Regulations should be directed to the Associate Administrator for Pipeline Safety, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, East Building, 2nd Floor, 1200 New Jersey Avenue, SE, Washington, D.C. 20590-0001.

PART 191

TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C 5121, 60101 et seq. and 49 CFR 1.97.

Source: Originally 35 FR 317, Jan. 8, 1970; currently Amdt. 191-25, 82 FR 7997, Jan. 23, 2017.

§191.1

Scope.

[Effective Date: 01/18/17]

(a) This part prescribes requirements for the reporting of incidents, safety-related conditions, annual pipeline summary data, National Operator Registry information, and other miscellaneous conditions by operators of underground natural gas storage facilities and natural gas pipeline facilities located in the United States or Puerto Rico, including underground natural gas facilities and pipelines within the limits of the Outer Continental Shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331). This part applies to offshore gathering lines (except as provided in paragraph (b) of this section) and to onshore gathering lines, including Type R gathering lines as determined in §192.8 of this chapter.

(b) This part does not apply to—

(1) Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;

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

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

(c) Sections 191.22(b) and (c) and 191.23 do not apply to the onshore gathering of gas—

(1) Through a pipeline that operates at less than 0 psig (0 kPa);

(2) Through a pipeline that is not a regulated onshore gathering pipeline; or

(3) Within inlets of the Gulf of Mexico, except for the requirements in §192.612 of this chapter.

[Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-6, 53 FR 24942, July 1, 1988 with Amdt. 191-6 Correction, 53 FR 26560, July 13, 1988; Amdt. 191-11, 61 FR 27789, June 3, 1996 with Amdt. 191-11 Correction, 61 FR 45905, Aug. 30, 1996; Amdt. 191-12, 62 FR 61692, Nov. 19, 1997 with Amdt. 191-12 Confirmation, 63 FR 12659, Mar. 16, 1998; Amdt. 191-15, 68 FR 46109, Aug. 5, 2003; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-24, 81 FR 91871, Dec. 19, 2016, Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

- (a) 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.
- (b) State regulations may be more stringent and require additional reporting for operators of intrastate pipelines. A NAPSRS document (2nd Edition 2013) provides a compendium of these additional state requirements and is available at www.napsr.org.
- (c) 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.
- (d) Sections 191.22(b) and (c) and 191.23 do not apply to Type R gathering pipelines.

§191.3

Definitions.

[Effective Date: 03/12/21]

As used in this part and the PHMSA Forms referenced in this part—

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

Confirmed Discovery means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation\

Gas means natural gas, flammable gas, or gas which is toxic or corrosive;

Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility, liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of \$122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in the calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.

(iii) Unintentional estimated gas loss of three million cubic feet or more.

(2) An event that results in an emergency shutdown of an LNG facility or an underground natural gas facility. Activation of an emergency shutdown system for reasons other than an actual emergency does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

LNG facility means a liquefied natural gas facility as defined in §193.2007 of part 193 of this chapter;

Master Meter System means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents;

Municipality means a city, count or any other political subdivision of a state;

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

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

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

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

Pipeline or Pipeline System means all parts of those physical facilities through which gas moves in transportation, including, but not limited to, pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

Regulated onshore gathering means a Type A, Type B, or Type C gas gathering pipeline system as determined in §192.8 of this chapter.

Reporting-regulated gathering means a Type R gathering line as determined in §192.8 of this chapter. A Type R gathering line is subject only to this part.

State includes each of the several states, the District of Columbia, and the Commonwealth of Puerto Rico;

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 an underground natural gas storage facility as defined in §192.3 of this chapter.

[Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-10, 61 FR 18512, Apr. 26, 1996; Amdt. 191-12, 62 FR 61692, Nov. 19, 1997 with Amdt. 191-12 Confirmation, 63 FR 12659, Mar. 16, 1998; RIN 2137-AD43, 68 FR 11748, Mar. 12, 2003; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-24, 81 FR 91871, Dec. 19, 2016; Amdt. 191-25, 82 FR 7997, Jan. 23, 2017; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

ADDITIONAL INCIDENT CONSIDERATIONS

- (a) State regulations may be more stringent and require additional reporting for operators of intrastate pipelines.
- (b) "In-patient hospitalization" means hospital admission and at least one overnight stay.
- (c) PHMSA may adjust the incident property damage reporting threshold for inflation. The adjustment, if implemented, will be effective July 1 of the notification year through June 30 of the following year. Operators should monitor PHMSA website for any adjustments to the threshold and adjust their written procedures as necessary.
- (d) Estimated property damage includes, but is not limited to, costs due to:
 - (1) Property damage to operator's facilities and property of others.
 - (2) Facility repair and replacement.
 - (3) Restoration of gas distribution service and relighting customers.
 - (4) Leak locating.
 - (5) Right-of-way cleanup.
 - (6) Environmental cleanup and damage.
- (e) Items to be considered when determining if an event may be significant include the following.
 - (1) Rupture or explosion.
 - (2) Fire.
 - (3) Loss of service.
 - (4) Evacuation of people in the area.
 - (5) Involvement of local emergency response personnel.
 - (6) Degree of media involvement.
- (f) For guidance on calculating gas loss from a damaged pipeline, see Guide Material Appendix G-191-5.

§191.5

Immediate notice of certain incidents.

[Effective Date: 03/24/17]

(a) At the earliest practicable moment following discovery, but no later than one hour after confirmed discovery, each operator must give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.

(b) Each notice required by paragraph (a) of this section must be made to the National Response Center either by telephone to 800-424-8802 (in Washington, DC, 202 267-2675) or electronically at <http://www.nrc.uscg.mil> and must include the following information:

- (1) Names of operator and person making report and their telephone numbers.
- (2) The location of the incident.
- (3) The time of the incident.
- (4) The number of fatalities and personal injuries, if any.
- (5) All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

(c) Within 48 hours after the confirmed discovery of an incident, to the extent practicable, an operator must revise or confirm its initial telephonic notice required in paragraph (b) of this section with an estimate of the amount of product released, an estimate of the number of fatalities and injuries, and all other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages. If there are no changes or revisions to the initial report, the operator must confirm the estimates in its initial report.

[Amdt. 191-1, 36 FR 7507, Apr. 21, 1971; Amdt. 191-4, 47 FR 32719, July 29, 1982; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-8, 54 FR 40878, Oct. 4, 1989; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010, Amdt. 191-25, 82 FR 7997, Jan. 23, 2017]

GUIDE MATERIAL

- (a) Section 191.5 requires that the initial incident notice must be made as soon as practicable, but no later than one hour after confirmed discovery of the incident as defined in §191.3. Complete information is not necessary for the initial electronic or telephonic incident notice to the National Response Center (NRC). This notice informs other government agencies at the earliest practicable moment without waiting for a definitive evaluation or determination that the event may meet the reporting requirements.
- (b) Refer to Guide Material Appendix G-191-1 for a sample worksheet that may be used to compile information for the initial incident notice. The information should include the following.
- (1) Name, address, and a 24-hour telephone number of the operator. An operator should consider providing a telephone number where more detailed information can be obtained.
 - (2) Time and date of incident.
 - (3) Location of incident, provided in a manner that will aid agencies in locating the site on maps. GPS coordinates, addresses and ZIP codes, and cross streets are useful.
 - (4) Facilities involved.
 - (5) Number of fatalities or injuries, if known.
 - (6) Estimate of property damage.
 - (7) Type of gas released, and an estimate of the quantity released. For guidance on calculating gas loss from a damaged pipeline, see Guide Material Appendix G-191-5.
 - (8) Evacuations and other emergency actions, if known.
 - (9) The responsible party, if known.
 - (10) Weather conditions at the incident site.

- (c) Section 191.5 states that an operator must confirm or revise the initial telephonic or electronic notice within 48 hours of the initial notice to the extent practicable. Updates may include revisions to the amount of gas released, number of fatalities or injuries, property damage, or other significant facts. The operator should clearly report to the NRC that additional information is being provided and give the NRC the initial notice's assigned NRC Report Number. The follow-up report may result in an additional NRC Report Number for the operator.
- (d) All related NRC Report Numbers should be referenced in the PHMSA-OPS electronic or written incident report (see §§191.9 and 191.15).
- (e) If an operator determines that an event for which an NRC notice has been made does not meet the PHMSA definition of an incident, and no 30-day report has been submitted, the operator is encouraged (but not required) to provide notification of that determination to the PHMSA Accident Investigation Division and to the state pipeline regulatory authority (if the event is investigated by the state). The e-mail address for the Accident Investigation Division is PHMSAAccidentInvestigationDivision@dot.gov.
- (f) If a 30-day incident report has been made as required in §191.9 (Form PHMSA F 7100.1) or §191.15 (Form PHMSA F7100.2) and further investigation reveals that the event was not an "incident," and therefore not reportable, the operator may request that their report be retracted. The Instructions for Form PHMSA F7100.1 and Form PHMSA F7100.2 state that requests are to be sent to the Information Resources Manager at the address specified in §191.7 or emailed to InformationResourcesManager@dot.gov. The instructions further state that requests are to include the following.
 - (1) The Report ID (the unique 8-digit identifier assigned by PHMSA).
 - (2) Operator name.
 - (3) PHMSA-issued OPID number.
 - (4) The number assigned by the NRC when an immediate notice was made in accordance with §191.5. If supplemental reports were made to the NRC for the event, list all NRC report numbers associated with the event.
 - (5) Date of the event.
 - (6) Location of the event.
 - (7) A brief statement as to why the report should be retracted.
- (g) For intrastate pipelines, it is necessary to comply with federal reporting requirements (§191.5) even though an "incident" (as defined in §191.3) has been reported to the appropriate state agency. State reporting obligations might differ from federal requirements and might require operators to report incidents not meeting the federal definition of an incident. States might also have shorter timeframes for reporting incidents than the timeframes in §191.5. The operator should consider providing (even if not required) the appropriate state agency with the same documents and reports that are provided to PHMSA.
- (h) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.
- (i) Operators are advised by the Transportation Security Administration (TSA) that if an event might have involved a breach of security of the pipeline facility, at the earliest practicable moment, the event should be reported to the Transportation Security Operations Center at 866-615-5150 or TSOC@dhs.gov.
- (j) Operators are advised by the following government agencies that if an event might have involved a breach of cyber-security of the pipeline control system (e.g., SCADA), at the earliest practicable moment, the event should be reported to:
 - (1) National Cybersecurity and Communications Integration Center (NCCIC) at 888-292-0870.
 - (2) Department of Homeland Security, ICS-CERT at 877-776-7585.

Note: See OPS Advisory Bulletin ADB-2016-06 (81 FR 89183, Dec. 9, 2016) and TSA Pipeline Security Guidelines (March 2018): reference Guide Material Appendix G-192-1, Section 2.

§191.7

Report submission requirements.

[Effective Date: 10/01/15]

(a) *General.* Except as provided in paragraphs (b) and (e) of this section, an operator must submit each report required by this part electronically to the Pipeline and Hazardous Materials Safety Administration at <http://portal.phmsa.dot.gov/pipeline> unless an alternative reporting method is authorized in accordance with paragraph (d) of this section.

(b) *Exceptions.* An operator is not required to submit a safety-related condition report (§191.25) electronically.

(c) *Safety-related conditions.* An operator must submit concurrently to the applicable State agency a safety-related condition report required by §191.23 for intrastate pipeline transportation or when the State agency acts as an agent of the Secretary with respect to interstate transmission facilities.

(d) *Alternative Reporting Method.* If electronic reporting imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to the Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075, or electronically to informationresourcesmanager@dot.gov or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

(e) *National Pipeline Mapping System (NPMS).* An operator must provide the NPMS data to the address identified 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.

[Amdt. 191-3, 46 FR 37250, July 20, 1981; Amdt. 191-4, 47 FR 32719, July 29, 1982; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-6, 53 FR 24942, July 1, 1988 with Amdt. 191-6 Correction, 53 FR 26560, July 13, 1988; Amdt. 191-16, 69 FR 32886, June 14, 2004; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; RIN 2137-AE29, 73 FR 16562, Mar. 28, 2008; RIN 2137-AE29 (#2), 74 FR 2889, Jan. 16, 2009; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-23, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

For National Pipeline Mapping System submission requirements, see §191.29.

§191.9

Distribution system: Incident report.

[Effective Date: 01/01/11]

(a) Except as provided in paragraph(c) of this section, each operator of a distribution pipeline system shall submit Department of Transportation Form RSPA F 7100.1 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

(b) When additional relevant information is obtained after the report is submitted under paragraph (a) of this section, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report.

(c) Master meter operators are not required to submit an incident report as required by this section.

[Amdt. 191-3, 46 FR 37250, July 20, 1981; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010]

GUIDE MATERIAL

(a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.

(b) Additional state reporting requirements may exist for intrastate facilities.

(c) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.

(d) Distribution operators with Type R gathering pipelines will have to submit separate incident reports for the Type R pipelines.

§191.11

Distribution system: Annual report.

[Effective Date: 03/12/21]

(a) *General.* Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system must submit an annual report for that system on DOT Form PHMSA F7100.1–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) *Not required.* The annual report requirement in this section does not apply to a master meter system, a petroleum gas system that serves fewer than 100 customers from a single source, or an individual service line directly connected to a production pipeline or a gathering line as determined in §192.8.

[Amdt. 191-2, 37 FR 1172, Jan. 26, 1972; Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010]

GUIDE MATERIAL

- (a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website www.phmsa.dot.gov/forms/pipeline-forms.
- (b) Additional state reporting requirements may exist for intrastate facilities.
- (c) Distribution operators with Type R gathering pipelines will have to submit separate annual reports for the Type R pipelines.

§191.12 [Reserved]

[Effective Date: 03/12/21]

§191.13

Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines.

[Effective Date: 06/04/84]

Each operator, primarily engaged in gas distribution, who also operates gas transmission or gathering pipelines shall submit separate reports for these pipelines as required by §§191.15 and 191.17. Each operator, primarily engaged in gas transmission or gathering, who also operates gas distribution pipelines shall submit separate reports for these pipelines as required by §§191.9 and 191.11.

[Amdt. 191-5, 49 FR 18956, May 3, 1984]

GUIDE MATERIAL

- (a) See §191.3 for definitions of regulated onshore gathering and reporting-regulated gathering. See §192.3 for definitions of *Distribution line*, *Gathering line*, and *Transmission lines*.
- (b) Additional state reporting requirements may exist for intrastate facilities, but federal reports for gathering lines are based on the definitions found in §192.8.

§191.15

Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident report.

[Effective Date: 01/18/17]

(a) *Pipeline systems— (1) Transmission or regulated onshore gathering.* Each operator of a transmission pipeline system or a regulated onshore gathering pipeline system must submit Department of Transportation (DOT) Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5.

(2) *Reporting-regulated gathering.* Each operator of a reporting-regulated gathering pipeline system must submit DOT Form PHMSA F 7100.2-2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 that occurs after May 16, 2022.

(b) *LNG.* Each operator of a liquefied natural gas plant or facility must submit DOT Form PHMSA F 7100.3 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 of this part.

(c) *Underground natural gas storage facility.* Each operator of an underground natural gas storage facility must submit DOT Form PHMSA F7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under § 191.5.

(d) *Supplemental report.* Where additional related information is obtained after a report is submitted under paragraph (a), (b) or (c) of this section, the operator must make a supplemental report as soon as practicable with a clear reference by date to the original report.

[Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-24, 81 FR 91871, Dec. 19, 2016; Amdt. 191-30, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

- (a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms, used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.
- (b) Additional state reporting requirements may exist for intrastate facilities.
- (c) Section 192.605 requires operators to have procedures to gather data for the reporting of incidents required by §191.5. See 2.3 and 5 of the guide material under §192.605 and the guide material under §192.617.
- (d) Transmission, Type A gathering, Type B gathering, and Type C gathering operators who also have Type R gathering pipelines will have to submit separate incident reports for the Type R pipelines (§191.15).

§191.17

Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Annual report.

[Effective Date: 01/18/17]

(a) *Pipeline systems— (1) Transmission or regulated onshore gathering.* Each operator of a transmission or a regulated onshore gathering pipeline system must submit an annual report for that system on DOT Form PHMSA 7100.2–1. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(2) *Type R gathering.* Beginning with an initial annual report submitted in March 2023 for the

2022 calendar year, each operator of a reporting-regulated gas gathering pipeline system must submit an annual report for that system on DOT Form PHMSA F 7100.2-3. This report must be submitted each year, not later than March 15, for the preceding calendar year.

(b) *LNG*. Each operator of a liquefied natural gas facility must submit an annual report for that system on DOT Form PHMSA 7100.3–1. This report must be submitted each year, not later than March 15, for the preceding calendar year, except that for the 2010 reporting year the report must be submitted by June 15, 2011.

(c) *Underground natural gas storage facility*. Each operator of a UNGSF must submit an annual report through DOT Form PHMSA 7100.4-1. This report must be submitted each year, no later than March 15, for the preceding calendar year.

[75 FR 72905, Nov. 26, 2010, as amended by Amdt. 191-24, 81 FR 91871, Dec. 19, 2016; Amdt. 191-27, 85 FR 8125, Feb. 12, 2020; Amdt. 191-30, 86 FR 63295, Nov. 15, 2021; Amdt. 191-32, 87 FR 35677. June 13, 2022]

GUIDE MATERIAL

- (a) See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms used for federal reporting. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms.
- (b) Federal reports for gathering lines are based on the definitions found in §192.8.
- (c) Additional state reporting requirements may exist for intrastate facilities.
- (d) For National Pipeline Mapping System submission requirements, see §191.29.
- (e) Operators will need to reflect changes due to service conversion (see §192.14) or product change (see §191.22(c)(1)(vi)) on subsequent Annual Reports.
- (f) Transmission, Type A gathering, Type B gathering, and Type C gathering operators who also have Type R gathering pipelines will have to submit separate annual and incident reports for the Type R pipelines (§191.17).

§191.21

OMB control number assigned to information collection.

[Effective Date: 01/18/17]

This section displays the control number assigned by the Office of Management and Budget (OMB) to the information collection requirements in this part. The Paperwork Reduction Act requires agencies to display a current control number assigned by the Director of OMB for each agency information collection requirement.

OMB CONTROL NUMBER 2137-0522

Section of 49 CFR Part 191 where identified	Form No.
191.5	Telephonic.
191.9	PHMSA 7100.1, PHMSA 7100.3.
191.11	PHMSA 7100.1-1, PHMSA 7100.3-1.
191.12	PHMSA 7100.1-2.
191.15	PHMSA 7100.2 PHMSA 7100.3.

OMB CONTROL NUMBER 2137-0522

Section of 49 CFR Part 191 where identified	Form No.
191.17	PHMSA 7100.2-1, PHMSA 7100.3-1, PHMSA 7100.4-1.
191.22	PHMSA 1000.1, PHMSA 1000.2.

[Issued by Amdt. 191-5, 49 FR 18956, May 3, 1984; Amdt. 191-13, 63 FR 7721, Feb. 17, 1998 with Amdt. 191-13 Confirmation, 63 FR 38757, July 20, 1998; Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt. 191-24, 81 FR 91871, Dec. 19, 2016]

GUIDE MATERIAL

No guide material necessary.

§191.22
National Registry of Pipeline and LNG Operators.
[Effective Date: 03/24/17]

(a) OPID Request. Effective January 1, 2012, each operator of a gas pipeline, gas pipeline facility, underground natural gas facility, LNG plant or LNG facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request DOT Form PHMSA F 1000.1 through the National Registry of Pipeline, Underground Natural Gas Storage Facility, and LNG Operators in accordance with §191.7.

(b) OPID validation. An operator who has already been assigned one or more OPID by January 1, 2011, must validate the information associated with each OPID through the National Registry of

Pipeline, Underground Natural Gas Storage Facility, and LNG Operators at <http://opsweb.phmsa.dot.gov>, and correct that information as necessary, no later than June 30, 2012.

(c) **Changes.** Each operator of a gas pipeline, gas pipeline facility, underground natural gas storage facility, LNG plant or LNG facility must notify PHMSA electronically through the National Registry of Pipeline, Underground Natural Gas Storage Facility, and LNG Operators at <http://opsweb.phmsa.dot.gov> of certain events.

(1) An operator must notify PHMSA of any of the following events not later than 60 days before the event occurs:

(i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs \$10 million or more. If 60 day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

(ii) Construction of 10 or more miles of a new pipeline or replacement pipeline;

(iii) Construction of a new LNG plant or LNG facility; or

(iv) Construction of a new underground natural gas storage facility or the abandonment, drilling or well workover (including replacement of wellhead, tubing, or a new casing) of an injection, withdrawal, monitoring, or observation well for an underground natural gas storage facility;

(v) Reversal of product flow direction when the reversal is expected to last more than 30 days. This notification is not required for pipeline systems already designed for bi-directional flow; or

(vi) A pipeline converted for service under § 192.14 of this chapter, or a change in commodity as reported on the annual report as required by § 191.17.

(2) An operator must notify PHMSA of any of the following events not later than 60 days after the event occurs:

(i) A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.

(ii) A change in the name of the operator;

(iii) A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, underground natural gas facility, or LNG facility;

(iv) The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter;

(v) The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter; or

(vi) The acquisition or divestiture of an existing underground natural gas storage facility subject to part 192 of this subchapter.

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

[Issued by Amdt. 191-21, 75 FR 72878, Nov. 26, 2010; Amdt 191-24, 81 FR 91872, Dec. 19, 2016; Amdt. 191-25, 82 FR 7997, Jan. 23, 2017]

GUIDE MATERIAL

- (a) Pipeline operators with Type R gathering pipelines must request an OPID (see §191.22(a)) and use the OPID for all reporting requirements (see §191.22(d)).
- (b) Type R pipelines are not considered regulated onshore gathering pipelines; therefore, §191.22(b) and (c) do not apply.
- (c) Section 191.22(c)(1) requires a notice not later than 60 days before certain construction events occur. Examples of construction activities that might trigger this advance notification to PHMSA under §191.22(c)(1) include the following.

- (1) Right-of-way clearing, grading, or ditching performed in advance of, but associated with the construction project.
- (2) Onsite equipment fabrication.
- (3) Onsite installation activities.

See OPS Advisory Bulletin ADB-2014-03 (79 FR 54777, Sept. 12, 2014; reference Guide Material Appendix G-192-1, Section 2).

- (d) Operators must notify PHMSA in accordance with §191.22(c)(1)(ii) for the construction of 10 or more miles of a new pipeline that did not previously exist.
- (e) Operators should notify PHMSA for the replacement of 10 or more contiguous miles of line pipe in an existing pipeline (see OPS Advisory Bulletin ADB-2014-03).
- (f) Operators must notify PHMSA in accordance with §191.22(c)(1)(vi) when the commodity being transported changes from one listed below to another gas listed below.
 - (1) Natural gas.
 - (2) Synthetic gas.
 - (3) Hydrogen gas.
 - (4) Propane gas.
 - (5) Landfill gas.
 - (6) Other gas.
- (g) See guide material under §192.14 for examples of conversion of service that would also require notice to PHMSA in accordance with §191.22(c)(1)(vi).

§191.23

Reporting safety-related conditions.

[Effective Date: 07/01/2020]

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

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

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

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

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

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

(6) Any malfunction or operating error that causes the pressure—plus the margin (build-up)

allowed for operation of pressure limiting or control devices—to exceed either the maximum allowable operating pressure of a distribution or gathering line, the maximum well allowable operating pressure of an underground natural gas storage facility, or the maximum allowable working pressure of an LNG facility that contains or processes gas or LNG.

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

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

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

(10) For transmission pipelines only, each exceedance of maximum allowable operating pressure that exceeds the margin (build-up) allowed for operation of pressure-limiting or control devices as specified in the applicable requirements of §§ 192.201, 192.620(e), and 192.739. 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.

(d) Gathering lines that are required to report safety related conditions under the requirements of §191.23(b) include:

(1) Type A.

(2) Type B.

- (3) Type C as follows.
 - (i) Greater than 12.75 inches in outside diameter which have a building suitable for human occupancy or other impacted site within the PIR or class location unit as defined in 192.9(f)(1)(i) and (ii).
 - (ii) Greater than 16 inches in outside diameter.
- (e) Reporting exceptions to safety-related condition requirement as outline in §191.23(b) include:
 - (1) Type R gathering lines.
 - (2) Type C gathering lines with an outside diameter of 12.75 inches or less.
 - (3) Type C gathering lines less than 16 inches in outside diameter that do not have a building suitable for human occupancy or other impacted site within the PIR or class location unit as defined in 192.9(f)(i) and (ii).

§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

- (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

- (a) 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.
- (b) Geospatial data is not required to be submitted to PHMSA for Types A, B, C, or R gathering pipelines.

Appendix A to Part 191
Qualification of Pipe.

[Effective Date: 05/09/2024]

GUIDE MATERIAL

Operators should check the PHMSA website for annual adjustments.

PART 192

TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 et. seq., and 49 CFR 1.97.

Source: Originally 35 FR 13248, Aug. 19, 1970; currently Amdt. 192-124, 83 FR 58694, Nov. 20, 2018.

SUBPART A GENERAL

§192.1

What is the scope of this part?

[Effective Date: 03/05/07]

- (a) This part prescribes minimum safety requirements for pipeline facilities and the transportation of gas, including pipeline facilities and the transportation of gas within the limits of the outer continental shelf as that term is defined in the Outer Continental Shelf Lands Act (43 U.S.C. 1331).
- (b) This part does not apply to—
- (1) Offshore gathering of gas in State waters upstream from the outlet flange of each facility where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream;
 - (2) Pipelines on the Outer Continental Shelf (OCS) that are producer-operated and cross into State waters without first connecting to a transporting operator's facility on the OCS, upstream (generally seaward) of the last valve on the last production facility on the OCS. Safety equipment protecting PHMSA-regulated pipeline segments is not excluded. Producing operators for those pipeline segments upstream of the last valve of the last production facility on the OCS may petition the Administrator, or designee, for approval to operate under PHMSA regulations governing pipeline design, construction, operation, and maintenance under 49 CFR 190.9;
 - (3) Pipelines on the Outer Continental Shelf upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator;
 - (4) Onshore gathering of gas—
 - (i) Through a pipeline that operates at less than 0 psig (0 kPa);
 - (ii) Through a pipeline that is not a regulated onshore gathering line (as determined in §192.8); and
 - (iii) Within inlets of the Gulf of Mexico, except for the requirements in §192.612; or
 - (5) Any pipeline system that transports only petroleum gas or petroleum gas/air mixtures to—
 - (i) Fewer than 10 customers, if no portion of the system is located in a public place; or

(ii) A single customer, if the system is located entirely on the customer's premises (no matter if a portion of the system is located in a public place).

[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 HV₁₀)

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 °F (38 °C).

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

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

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

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

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 *wrinkle 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

Glossary of Commonly Used Terms

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

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

Abandonment is the process of abandoning a pipeline.

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

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

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

Bottle is a gastight structure that is (1) completely fabricated by the manufacturer from pipe with integral drawn,

forged, or spun end closures; and (2) tested in the manufacturer's plant. See also *Bottle-type holder*. *Bottle-type holder* is any bottle or group of interconnected bottles installed in one location, and used for the sole purpose of storing gas. See also *Bottle*.

Carbon steel. By common custom, steel is considered to be carbon steel where (i) no minimum content is specified or required for aluminum, boron, chromium, cobalt, columbium, molybdenum, nickel, titanium, tungsten, vanadium, zirconium, or any other element added to obtain a desired alloying effect; (ii) the specified minimum content for copper does not exceed 0.40 percent; or (iii) the specified maximum content does not exceed 1.65 percent for manganese, 0.60 percent for silicon or 0.60 percent for copper.

All carbon steels may contain small quantities of unspecified residual elements unavoidably retained from raw materials. These elements (copper, nickel, molybdenum, chromium, etc.) are considered incidental and are not normally determined or reported.

Cast iron. The unqualified term cast iron applies to gray-cast iron that is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed through the metal.

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

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

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

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

Control piping is pipe, valves, and fittings used to interconnect air, gas, or hydraulically operated control apparatus.

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

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

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

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

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

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

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

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

of chemistry and a ferritizing heat treatment of the castings.

Electric-flash-welded pipe is pipe having a longitudinal butt joint wherein coalescence is produced, simultaneously over the entire area of abutting surfaces, by the heat obtained from resistance to the flow of electric current between the two surfaces, and by the application of pressure after heating is substantially completed. Flashing and upsetting are accompanied by the expulsion of metal from the joint. Typical specification (see §192.7): API Spec 5L. See also *Pipe manufacturing processes*.

Electric-fusion-welded pipe is pipe having a longitudinal butt joint wherein coalescence is produced in the preformed tube by manual or automatic electric-arc welding. The weld may be single or double and may be made with or without the use of filler metal. Typical specifications (see §192.7 and Guide Material Appendix G-192-1A): ASTM A134, ASTM A139: Single or double weld is permitted with or without the use of filler metal. ASTM A671, ASTM A672, ASTM A691, and API Spec 5L: Requires both inside and outside welds and use of filler metal.

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

Electric-resistance-welded (ERW) pipe is pipe, which has a longitudinal butt joint wherein coalescence, is produced by the application of pressure and by the heat obtained from the resistance of the pipe to the flow of an electric current in a circuit of which the pipe is a part. It is produced in individual lengths or in continuous lengths from coiled skelp and subsequently cut into individual lengths. Typical specifications (see §192.7 and Guide Material Appendix G-192-1A): ASTM A53, ASTM A135, and API Spec 5L. See also *Pipe manufacturing processes*.

Electrolyte is a chemical substance containing ions that migrate in an electric field. Electrolytes can play a role in external corrosion or internal corrosion of metallic pipelines. For external corrosion, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged piping system, including the moisture and other chemicals contained therein. For internal corrosion, electrolyte refers to the chemicals contained in water inside the pipeline, including solutions of salts, acids, and bases.

Electrolytic contact (also known as an electrolytic couple or electrolytic short) is ionic contact between two metallic structures via an electrolyte.

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

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

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

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

Furnace-lap-welded pipe is pipe that has a longitudinal lap joint that is produced by the forge welding process. In this process, coalescence is produced by heating a preformed tube to welding temperature and then passing it over a mandrel. The mandrel is located between the two welding rolls that compress and weld the overlapping edges. Typical specification: API Spec 5L. The manufacture of this type of pipe was discontinued, and the process was deleted from API Spec 5L in 1962 (see §192.7 and Guide Material Appendix G-192-1A). See also *Pipe manufacturing processes*.

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

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

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

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

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

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

$$S_h = \frac{PD}{2t}$$

Where:

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

See also *Maximum allowable hoop stress*.

Hot taps are connections made to transmission lines, mains, or other facilities while they are in operation.

The connecting and tapping is done while the facility is under gas pressure.

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

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

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

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

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

Jeeping is a method of *Holiday detection*.

Joint. See *Length*.

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

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

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

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

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

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

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

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

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

Metallic short is direct metallic contact between two metallic structures.

Meters. See *Meter set assembly*.

Meter set assembly is that exposed portion of the service line extending from the service line riser valve to

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

Monitoring regulator is a pressure regulator, set in series with another pressure regulator, for the purpose of providing automatic overpressure protection in the event of a malfunction of the primary regulator.

Nodular iron. See *Ductile iron*.

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

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

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

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

Otherwise changed is a substantial physical alteration of a pipeline facility as opposed to a repair or restoration (Amdt. 192-102). The original alignment or functionality of the pipeline facility is modified by the alteration. Examples of a substantial physical alteration include the following.

- (a) Addition of a pig launcher or receiver to a pipeline.
- (b) Addition of a mainline block valve.
- (c) Relocation of a pipeline.
- (d) Connection of a lateral.

Overpressure protection is the use of a device or equipment installed for the purpose of preventing pressure in a pipe system or other facility from exceeding a predetermined limit. See also *Pressure limiting station*, *Pressure regulating station*, and *Pressure relief station*.

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

Pipe. See *Bell-welded pipe*, *Cold-expanded pipe*, *Continuous-welded pipe*, *Control piping*, *Double-submerged-arc-welded pipe*, *Electric-flash-welded pipe*, *Electric-fusion-welded pipe*, *Electric-resistance-welded pipe*, *Furnace-butt-welded pipe*, *Furnace-lap-welded pipe*, *Instrument piping*, *Length*, *Pipe-container*, *Pipe manufacturing processes*, *Pipe-type holder*, *Sample piping*, and *Seamless pipe*.

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

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

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

Furnace-lap-welded pipe
Seamless pipe

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

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

Plastic pipe joints. See *Adhesive joint*, *Heat-fusion joint*, and *Solvent cement joint*.

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

Pressure limiting station consists of apparatus which, under abnormal conditions, will act to reduce, restrict, or shut off the supply of gas flowing into a transmission line, main, holder, pressure vessel, or compressor station piping in order to prevent the gas pressure from exceeding a predetermined limit. While normal pressure conditions prevail, the pressure limiting station may exercise some degree of control of the flow of gas or may remain in the wide-open position. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.

Pressure regulating station consists of apparatus installed for the purpose of automatically reducing and regulating the gas pressure in the downstream transmission line, main, holder, pressure vessel, or compressor station piping to which it is connected. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.

Pressure relief station consists of apparatus installed to vent gas from a transmission line, main, holder, pressure vessel, or compressor station piping in order to prevent the gas pressure from exceeding a predetermined limit. The gas may be vented into the atmosphere or into a lower pressure gas system capable of safely receiving the gas being discharged. Included in the station are any enclosures and ventilating equipment, and any piping and auxiliary equipment, such as valves, control instruments, or control lines.

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

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

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

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

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

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

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

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

Seamless pipe is a wrought tubular product made without a welded seam. It is manufactured by hot working steel or, if necessary, by subsequently cold finishing the hot-worked tubular product to produce the desired shape, dimensions, and properties. See also *Pipe manufacturing processes*.

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

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

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

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

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

Standup pressure test is a test to demonstrate that a pipe or piping system does not leak as evidenced by the lack of a drop in pressure over a specified period of time after the source of pressure has been isolated.

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

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

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

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

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

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

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

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

Thermosetting plastic is a plastic that is capable of being changed into a substantially infusible or insoluble product when cured under the application of heat or by chemical means. Examples of thermosetting plastic materials include:

- (a) Epoxy as used in epoxy fiberglass pipe, "Red Thread®" pipe, and fiber-reinforced pipe (FRP); and
- (b) Unsaturated polyester as used in fiberglass composites for steel pipe repair sleeves, and cured-in-place (CIP).

Thickness. See *Nominal wall thickness*.

Valve. See *Curb valve* and *Service-line valve*.

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

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

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

GLOSSARY OF COMMONLY USED ABBREVIATIONS	
<i>Note: For added organizational abbreviations, see Guide Material Appendix G-192-1, Sections 4 and 5.</i>	
Abbreviation	Meaning
ABS	acrylonitrile-butadiene-styrene
ACVG	alternating current voltage gradient
AOC	abnormal operating condition
ASV	automatic shut-off valve
BAP	baseline assessment plan
CAB	cellulose acetate butyrate
CDA	confirmatory direct assessment
CGI	combustible gas indicator
CIS	close-interval survey
CP	cathodic protection
CTS	copper tube size
DA	direct assessment
DCVG	direct current voltage gradient
DIMP	Distribution Integrity Management Program
ECA	engineering critical assessment
ECDA	external corrosion direct assessment
EFV	excess flow valve
EFVB	excess flow valve – bypass (automatic reset)
EFVNB	excess flow valve – non-bypass (manual reset)
ERW	electric resistance welded
ESD	emergency shutdown
FAQ	frequently asked question
FBE	fusion bonded epoxy
FRP	fiberglass reinforced plastic
GIS	geographic information system
GMA	Guide Material Appendix
GPS	global positioning system
H ₂ S	hydrogen sulfide
HCA	high consequence area
HDB	hydrostatic design basis
HFI	hydrogen flame ionization

GLOSSARY OF COMMONLY USED ABBREVIATIONS (Continued)	
Abbreviation	Meaning
IBR	Incorporated by reference (see §192.7)
IC	internal corrosion
ICDA	internal corrosion direct assessment
ICS	Incident Command System
ILI	in-line inspection
IMP	integrity management program
IPS	iron pipe size
IR drop	voltage drop
LEL	lower explosive limit
LNG	liquefied natural gas
LPG	liquid or liquefied petroleum gas
LTHS	long-term hydrostatic strength
MAOP	maximum allowable operating pressure
MIC	microbiologically influenced corrosion
MOC	management of change
MOP	maximum operating pressure
MRS	minimum required strength
NAPSR	National Association of Pipeline Safety Representatives
NDE	nondestructive evaluation
NPS	nominal pipe size
O ₂	oxygen
O&M	operations and maintenance
OCS	outer continental shelf
OQ	operator qualification
PA	polyamide
P&M measures	preventive and mitigative measures
PDB	pressure design basis
PE	polyethylene
PFP	predicted failure pressure
PIC	potential impact circle
PIR	potential impact radius
PVC	poly (vinyl chloride), also written as polyvinyl chloride
RCV	remote control valve
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SCCDA	stress corrosion cracking direct assessment
SCFH	standard cubic feet per hour
SDB	strength design basis
SDR	standard dimension ratio
SME	subject matter expert
SMYS	specified minimum yield strength
TVC	traceable, verifiable, and complete
USGS	United States Geological Survey
USCG	United States Coast Guard

TABLE 192.3i

§192.5

Class locations.

[Effective Date: 07/01/2020]

- (a) This section classifies pipeline locations for purposes of this part. The following criteria apply to classifications under this section.
- (1) A "class location unit" is an onshore area that extends 220 yards (200 meters) on either side of the centerline of any continuous 1- mile (1.6 kilometers) length of pipeline.
 - (2) Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.
- (b) Except as provided in paragraph (c) of this section, pipeline locations are classified as follows:
- (1) A Class 1 location is:
 - (i) An offshore area; or
 - (ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.
 - (2) A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.
 - (3) A Class 3 location is:
 - (i) Any class location unit that has 46 or more buildings intended for human occupancy; or
 - (ii) An area where the pipeline lies within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)
 - (4) A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.
- (c) The length of Class locations 2, 3, and 4 may be adjusted as follows:
- (1) A Class 4 location ends 220 yards (200 meters) from the nearest building with four or more stories above ground.
 - (2) When a cluster of buildings intended for human occupancy requires a Class 2 or 3 location, the class location ends 220 yards (200 meters) from the nearest building in the cluster.
- (d) An operator must have records that document the current class location of each pipeline segment and that demonstrate how the operator determined each current class location in accordance with this section.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-56, 52 FR 32924, Sept. 1, 1987; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996 and Amdt. 192-78 Correction, 61 FR 35139, July 5, 1996; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt 192-125, Oct. 1, 2019]

GUIDE MATERIAL

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

§192.7

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

[Effective Date: 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," 7 th 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," 1 st edition, April 2000, (API RP 80).	§192.8(a).
(5) API Recommended Practice 1162, "Public Awareness Programs for Pipeline Operators," 1 st 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," 45 th 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," 23 rd 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 <i>potential impact radius</i> ; 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)	
(10) ASME Boiler & Pressure Vessel Code, Section IX: “Qualification Standard for Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators,” 2007 edition, July 1, 2007, (ASME BPVC, Section IX).	§§192.225(a); 192.227(a); and Item II, Appendix B to Part 192.
(d) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228, phone: 800-222-2768, website: https://www.asnt.org/ .	
(1) ANSI/ASNT ILI—PQ—2005(2010), “In-line Inspection Personnel Qualification and Certification,” Reapproved October 11, 2010, (ANSI/ASNT ILI—PQ)	§ 192.493
(2) [Reserved]	
(e) ASTM International (formerly American Society for Testing and Materials), 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA 19428, phone: (610) 832–9585, website: http://astm.org .	
(1) ASTM A53/A53M–10, “Standard Specification for Pipe, Steel, Black and Hot-Dipped, Zinc-Coated, Welded and Seamless,” approved October 1, 2010, (ASTM A53/A53M).	§192.113; and Item II, Appendix B to Part 192.
(2) ASTM A106/A106M–10, “Standard Specification for Seamless Carbon Steel Pipe for High-Temperature Service,” approved October 1, 2010, (ASTM A106/A106M).	§192.113; and Item I, Appendix B to Part 192.
(3) ASTM A333/A333M–11, “Standard Specification for Seamless and Welded Steel Pipe for Low-Temperature Service,” approved April 1, 2011, (ASTM A333/A333M).	§192.113; and Item I, Appendix B to Part 192.
(4) ASTM A372/A372M–10, “Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Pressure Vessels,” approved October 1, 2010, (ASTM A372/A372M).	§192.177(b).
(5) ASTM A381–96 (reapproved 2005), “Standard Specification for Metal-Arc Welded Steel Pipe for Use with High-Pressure Transmission Systems,” approved October 1, 2005, (ASTM A381).	§192.113; and Item I, Appendix B to Part 192.
(6) ASTM A578/A578M–96 (reapproved 2001), “Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications,” (ASTM A578/A578M).	§192.112(c).
(7) ASTM A671/A671M–10, “Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and Lower Temperatures,” approved April 1, 2010, (ASTM A671/A671M).	§192.113; and Item I, Appendix B to Part 192.
(8) ASTM A672/A672M–09, “Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures,” approved October 1, 2009, (ASTM A672/672M).	§192.113; and Item I, Appendix B to Part 192.
(9) ASTM A691/A691M–09, “Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded for High-Pressure Service at High Temperatures,” approved October 1, 2009, (ASTM A691/A691M).	§192.113; and Item I, Appendix B to Part 192.
(10) ASTM D638–03, “Standard Test Method for Tensile Properties of Plastics,” 2003, (ASTM D638).	§192.283(a) and (b).

	IBR approved for: (Continued)
(11) ASTM D2513–18a, “Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings,” approved August 1, 2018, (ASTM D2513)	Item I, Appendix B to Part 192.
(12) ASTM D2517–00, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings,” (ASTM D 2517).	§§192.191(a); 192.281(d); 192.283(a); and Item I, Appendix B to Part 192.
(13) ASTM D2564–12, “Standard Specification for Solvent Cements for Poly (Vinyl Chloride)(PVC) Plastic Piping Systems,” Aug. 1, 2012, (ASTM D2564-12).	§192.281(b)(2).
(14) ASTM F1055–98 (Reapproved 2006), “Standard Specification for Electrofusion Type Polyethylene Fittings for Outside Diameter Controlled Polyethylene Pipe and Tubing,” March 1, 2006, (ASTM F1055-98 (2006)).	§192.283(a); Item I, Appendix B to Part 192.
(15) ASTM F1924-12, “Standard Specification for Plastic Mechanical Fittings for use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing,” April 1, 2012, (ASTM F1924-12).	Item I, Appendix B to Part 192.
(16) ASTM F1948-12, “Standard Specification for Metallic Mechanical Fittings for use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing,” April 1, 2012, (ASTM F1948-12).	Item I, Appendix B to Part 192.
(17) ASTM F1973-13, “Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Systems,” May 1, 2013, (ASTM F1973-13).	§192.204(b); and Item I, Appendix B to Part 192.
(18) ASTM F2145-13, “Standard Specification for Polyamide 11 (PA11) and Polyamide 12 (PA12) Mechanical Fittings for use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing,” May 1, 2013, (ASTM F2145-13).	Item I, Appendix B to Part 192.
(19) ASTM F2600-09, “Standard Specification for Electrofusion Type Polyamide-11 Fittings for use on Outside Diameter Controlled Polyamide-11 Pipe and Tubing,” April 1, 2009, (ASTM F2600-09).	Item I, Appendix B to Part 192.
(20) ASTM F2620–19, “Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings,” approved February 1, 2019, (ASTM F2620).	§§ 192.281(c) and 192.285(b).
(21) ASTM F2767-12, “Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution,” Oct. 15, 2012, (ASTM F2767-12).	Item I, Appendix B to Part 192.
(22) ASTM F2785-12, “Standard Specification for Polyamide 12 Gas Pressure Pipe, Tubing and Fittings,” Aug. 1, 2012, (ASTM F2785-12).	Item I, Appendix B to Part 192.
(23) ASTM F2817-10, “Standard Specification for Poly (Vinyl Chloride)(PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair,” Feb. 1, 2010, (ASTM F2817-10).	Item I, Appendix B to Part 192.

	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.ttoolbox.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

1 GENERAL

1.1 Incorporated by reference (IBR) documents.

- (a) When an IBR document is approved for a code section, the content of the document is required to be followed to comply with the code section as applicable. The edition of the IBR document specified in §192.7 is the edition that must be followed, even if the standards-developing organization has issued a more recent edition (§192.7(a)).
- (b) When a document is included in §192.7 as an IBR document, it does not necessarily mean that the entire document is IBR. The code section for which it is approved will identify the extent of what is applicable in the IBR.

Example:

§192.225 Welding Procedures

- (a) Welding must be performed by a qualified welder or welding operator in accordance with welding procedures qualified under section 5, section 12, Appendix A or Appendix B of API Std 1104 (incorporated by reference, see §192.7), or ...

1.2 Reference to incorporated by reference (IBR) documents in the Guide.

- (a) Reference to an IBR document in guide material under a code section for which the IBR is approved will normally refer to “(see §192.7 for IBR).”

- (b) Reference to an IBR document in guide material under a code section (§192.xxx) for which the IBR is not approved will normally refer to “(see listing in §192.7, not IBR for §192.xxx).” In this case, the IBR document is recommended for additional guidance.
- (c) For multiple references to the same IBR document in a section of guide material, the parenthetical expression will normally appear after the first reference.

1.3 Reference to non-IBR documents in the Guide.

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.

1.4 Previous IBR documents.

See Guide Material Appendix G-192-1A for documents previously incorporated by reference in the Regulations.

§192.8

How are onshore gathering pipelines and regulated onshore gathering pipelines determined?

[Effective Date: 04/14/06]

(a) An operator must use API RP 80 (incorporated by reference, see §192.7), to determine if an onshore pipeline (or part of a connected series of pipelines) is an onshore gathering line. The determination is subject to the limitations listed below. After making this determination, an operator must determine if the onshore gathering line is a regulated onshore gathering line under paragraph (b) of this section.

(1) The beginning of gathering, under section 2.2(a)(1) of API RP 80, may not extend beyond the furthestmost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthestmost downstream point does not include equipment that can be used in either production or transportation, such as separators or dehydrators, unless that equipment is involved in the processes of “production and preparation for transportation or delivery of hydrocarbon gas” within the meaning of “production operation.”

(2) The endpoint of gathering, under section 2.2(a)(1)(A) of API RP 80, may not extend beyond the first downstream natural gas processing plant, unless the operator can demonstrate, using sound engineering principles, that gathering extends to a further downstream plant.

(3) If the endpoint of gathering, under section 2.2(a)(1)(C) of API RP 80, is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles from each other, unless the Administrator finds a longer separation distance is justified in a particular case (see 49 CFR §190.9).

(4) The endpoint of gathering, under section 2.2(a)(1)(D) of API RP 80, may not extend beyond the furthestmost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

(5) For new, replaced, relocated, or otherwise changed gas gathering pipelines installed after May 16, 2022, the endpoint of gathering under sections 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 (incorporated by reference, see §192.7)— also known as “incidental gathering”— may not be used if the pipeline terminates 10 or more miles downstream from the furthestmost downstream endpoint as define in paragraphs 2.2(a)(1)(A) through (a)(1)(D) of API RP 80 (incorporated by reference, see §192.7) and this section. If an “incidental gathering” pipeline is 10 miles or more in length, the entire portion of the pipeline that is designated as an incidental gathering line under 2.2(a)(1)(E) and 2.2.1.2.6 of API RP 80 shall be classified as transmission pipeline subject to all applicable regulations in this chapter for transmission pipelines.

(b) Each operator must determine and maintain for the life of the pipelines records documenting the methodology by which it calculated the beginning and end points of each onshore gathering pipeline it operates, as described in the second column of table 1 to paragraph (c)(2) of this section, by:

(1) November 16, 2022, or before the pipeline is placed into operation, whichever is later; or

(2) An alternative deadline approved by the Pipeline and Hazardous Materials Safety Administration (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 the following information:

(i) Description of the affected facilities and operating environment;

(ii) Justification for an alternative compliance deadline; and

(iii) Proposed alternative deadline.

(c) For purposes of part 191 of this chapter and §192.9, the term “regulated onshore gathering pipeline” means:

(1) Each Type A, Type B, or Type C onshore gathering line (or segment of onshore

gathering line) with a feature described in the second column of table 1 to paragraph (c)(2) of this section that lies in an area described in the third column; and

(2) As applicable, additional lengths of pipeline described in the fourth column to provide a safety buffer:

Type	Feature	Area	Safety Buffer
A	<p>— Metallic and the MAOP produces a hoop stress of 20 percent or more of SMYS.</p> <p>—If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.</p> <p>— Non-metallic and the MAOP is more than 125 psig (862 kPa).</p>	<p>Class 2, 3, or 4 location (see §192.5).</p>	<p>None.</p>
B	<p>— Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.</p> <p>— Non-metallic and the MAOP is 125 psig (862 kPa) or less.</p>	<p>Area 1. Class 3 or 4 location.</p> <p>Area 2. An area within a Class 2 location the operator determines by using any of the following three methods:</p> <p>(a) A Class 2 location.</p> <p>(b) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1 mile (1.6 km) of pipeline and including more than 10 but fewer than 46 dwellings.</p> <p>(c) An area extending 150 feet (45.7 m) on each side of the centerline of any continuous 1000 feet (305 m) of pipeline and including 5 or more dwellings.</p>	<p>If the gathering line is in Area 2(b) or 2(c), the additional lengths of line extend upstream and downstream from the area to a point where the line is at least 150 feet (45.7 m) from the nearest dwelling in the area. However, if a cluster of dwellings in area 2(b) or 2(c) qualifies a pipeline as Type B, the Type B classification ends 150 feet (45.7 m) from the nearest dwelling in the cluster.</p>

Table continued on next page

C	<p>— Metallic and the MAOP produces a hoop stress of less than 20 percent of SMYS. If the stress level is unknown, an operator must determine the stress level according to the applicable provisions in subpart C of this part.</p> <p>— Non-metallic and the MAOP is 125 psig (862 kPa) or less.</p>	Class 1 location	None.
R	— All other onshore gathering lines	Class 1 and Class 2 locations	None.

(3) A Type R gathering line is subject to reporting requirements under part 191 of this chapter but is not a regulated onshore gathering line under this part.

[Issued by Amdt. 192-102, 71 FR 13289, Mar. 15, 2006; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

1 DEFINITION

Section 192.8 requires the operator to combine the definitions of gathering line in API RP 80, "Guidelines for the Definition of Onshore Gas Gathering Lines" (see §192.7 for IBR) and §192.3 with the limitations described in §192.8(a). This is to determine whether a pipeline is a gathering line and, if so, to determine the beginning and ending.

From reviewing the gathering line definitions in §192.3 and API RP 80, Section 2.2, "Definition of Onshore Gathering Line," plus considering the limitations in §192.8(a), a functional definition is as follows.

- (a) *Gathering line* means a pipeline or part of a connected series of pipelines used to transport gas as follows.
- (1) From the furthest downstream point in a current production operation to a transmission line or main.
 - (2) From a point other than within a production operation to points in or adjacent to one or more production operations or gathering facility sites for use as fuel, gas lift, or injection gas within those operations.
 - (3) From intermediate delivery connections to other production operations, pipeline facilities, farm taps, or residential / commercial / industrial end users that are not part of the gathering line.
- (b) The beginning of gathering starts at the furthest downstream point in a current production operation (see 2.3 of API RP 80).

- (c) The ending of gathering is the furthestmost downstream endpoint as follows.
- (1) The inlet of the first natural gas processing plant that is not located on a transmission line, unless the operator can demonstrate through sound engineering principles that gathering extends to a plant farther downstream.
 - (2) The outlet of the farthest downstream gas treatment facility.
 - (3) The farthest downstream point where gas produced in the same production field or separate production fields is commingled, subject to the following limitation.
Limitation: If the endpoint is determined by the commingling of gas from separate production fields, the fields may not be more than 50 miles apart, unless the PHMSA Administrator finds a longer separation distance is justified in a particular case. (See §190.9 for requirements regarding petitions to PHMSA-OPS.)
 - (4) The outlet of the farthest downstream compressor station used to increase gathering line pressure for delivery to a transmission line or main.
 - (5) The connection to another pipeline downstream of either of the following.
 - (i) The endpoints identified in (1), (2), (3), or (4) above.
 - (ii) The furthestmost downstream production operation.
- (d) A gathering line does not include a natural gas processing plant.

2 TYPE OF GATHERING LINE

After identifying a gathering line, the operator of an onshore gathering line is required to determine whether the gathering line is Type A, Type B, Type C, or Type R (see §192.8(a)). All offshore gathering lines are regulated (see §192.9(b)).

2.1 Type A gathering line.

- (a) A Type A gathering line is one located in a Class 2, 3, or 4 location to which either of the following conditions apply.
- (1) A non-metallic line (e.g., plastic or fiberglass) where the MAOP is greater than 125 psig.
 - (2) A steel line where the MAOP is equal to or greater than 20% SMYS.
 - (i) The stress determination for a steel line is made by using Barlow's formula for hoop stress and multiplying by 0.20. Barlow's formula for hoop stress is:

$$P_{100} = \frac{2St}{D}$$

Where:

- P_{100} = Pressure at 100% SMYS, psig
 S = Specified Minimum Yield Strength of the pipe
 t = Wall thickness, inches
 D = Nominal outside diameter, inches (see 2 of the guide material under §192.105)

- (ii) If the gathering line MAOP is equal to or greater than P_{100} multiplied by 0.20, the gathering line is Type A.
 - (iii) If the pipe yield strength is unknown, or if the pipe was manufactured in accordance with a specification not listed in Section I of Appendix B to Part 192, see the guide material under §192.107.
- (b) Type A gathering lines are subject to the requirements of §192.9(c).

2.2 Type B gathering line.

- (a) A Type B gathering line is one that meets both of the following conditions.
- (1) Condition 1 - Material and MAOP.

- (i) A steel pipeline where the MAOP is less than 20% SMYS, or
 - (ii) A non-metallic pipeline (e.g., plastic or fiberglass) where the MAOP is equal to or less than 125 psig.
- (2) Condition 2 - Class location.
- (i) A pipeline that lies within a Class 3 or Class 4 location (if so, it is considered an "Area 1" under §192.8(b)), or
 - (ii) A pipeline that lies within a Class 2 location that the operator determines by choosing any one of the following three methods (if so, it is considered an "Area 2(a)," "Area 2(b)," or "Area 2(c)" under §192.8(b)).
 - (A) A Class 2 location (Area 2(a)).
 - (B) An area extending 150 feet on each side of the centerline of any continuous 1 mile of pipeline that includes more than 10 but fewer than 46 dwellings, plus a safety buffer (Area 2(b)).
 - (C) An area extending 150 feet on each side of the centerline of any continuous 1,000 feet of pipeline and including 5 or more dwellings, plus a safety buffer (Area 2(c)).
- (b) Type B, Area 2 gathering line safety buffer.
After determining that the gathering line is a Type B, Area 2(b) or (c), the safety buffer is a length of pipeline that extends upstream and downstream from the area to a point where the line is at least 150 feet from the nearest dwelling in the area. However, if a cluster of dwellings in the area qualifies a line as a Type B gathering line, the Type B classification ends 150 feet from the outermost dwellings in the cluster.
- Note:* The safety buffer could possibly extend into a Class 1 location.
- (c) Examples of Area 2(b) and (c) length determinations.
- (1) Area 2(b) example. In Figure 192.8A, the length of the Type B segment is determined using the sliding mile method. This is similar to a typical class location survey, with the exception that 150 feet is used instead of 660 feet on either side of the centerline of the pipe. The length of Type B pipe can be adjusted shorter or longer depending on the locations of the dwellings within the mile.

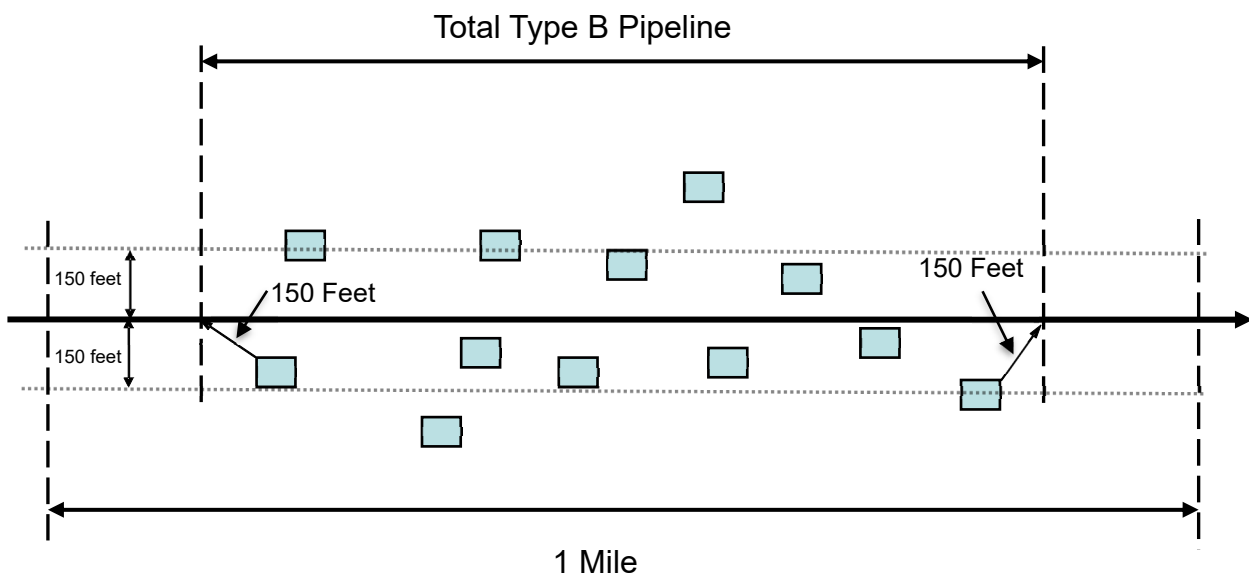


FIGURE 192.8A

- (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 Type B. Therefore, the Type B 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.

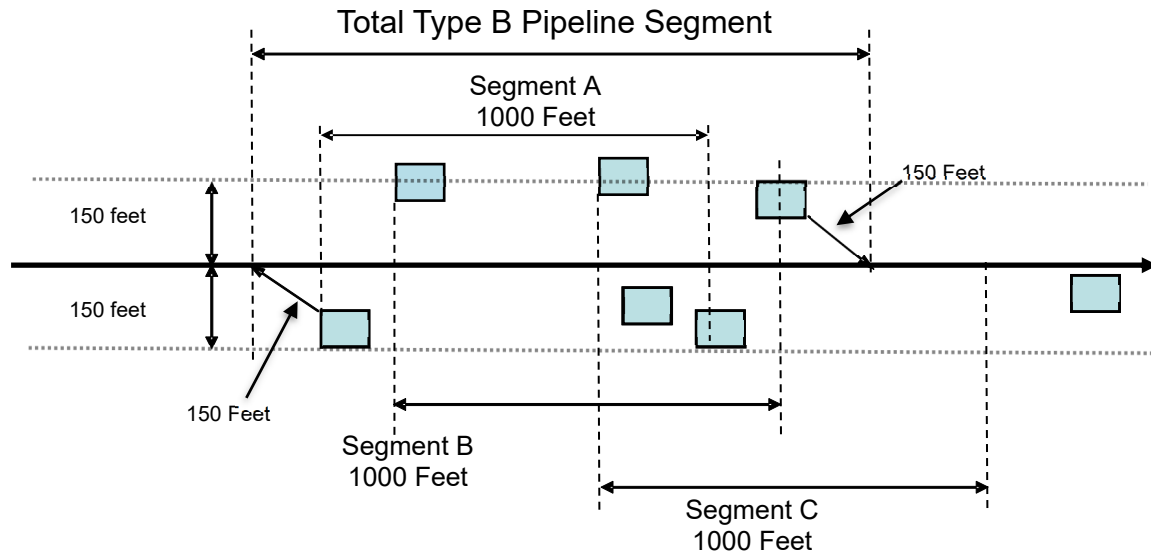


FIGURE 192.8B

2.3 Type C gathering line.

- (a) A Type C gathering line has an outer diameter equal to or greater than 8.625 inches and is located in a Class 1 location to which either of the following conditions apply.
- (1) A non-metallic line (e.g., plastic, composite pipe) where the MAOP is greater than 125 psig.
 - (2) A steel line where the MAOP is equal to or greater than 20% SMYS.
 - (3) A steel line with an unknown stress level and the MAOP is greater than 125 psig.
- (b) Type C gathering lines are subject to the requirements of §192.9(e).

2.4 Type R gathering line.

- (a) Gathering pipeline segments not determined to be Type A, B, or C are Type R.
- (b) Type R gathering lines are defined in §192.8, but are not subject to other Part 192 requirements.
- (c) Gathering lines that operate at less than 0 psig are Type R lines.
- (d) See guide material under Part 191 for Type R requirements.

2.5 Gathering lines in inlets of Gulf of Mexico

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)).

2.6 Recordkeeping.

To document the gathering line beginning and endpoints, use the class location and the following items:

- (a) Materials.
 - (1) For steel lines.
 - (i) Grade (specified minimum yield strength). If grade is unknown, use the default of 24,000 psi per §192.107(b)(2).
 - (ii) Wall thickness.
 - (iii) Nominal diameter.

- (2) For non-metallic lines.
 - (i) Material (e.g., PE, PA, composite).
 - (ii) Diameter.
 - (iii) Standard Dimension Ratio (SDR) or other known pipe characteristics.
- (b) Maximum Allowable Operating Pressure (MAOP).
 - (1) MAOP is not required to be determined for Type C lines with an outer diameter less than or equal to 12.75 inches.
 - (2) MAOP is required to be determined by §192.619(a) or (c) for Type C lines with an outer diameter greater than 12.75 inches (§192.9(e)(2)(ii)).
- (c) Examples of documentation could be the following.
 - (1) Electronic mapping.
 - (2) Paper mapping.
 - (3) GPS locations.
 - (4) Stationing.
 - (5) Other means that define the beginning and endpoints of the various types of segments.
- (d) Operators are required to retain records for the life of each onshore gathering line segment (§192.8(b)).

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.

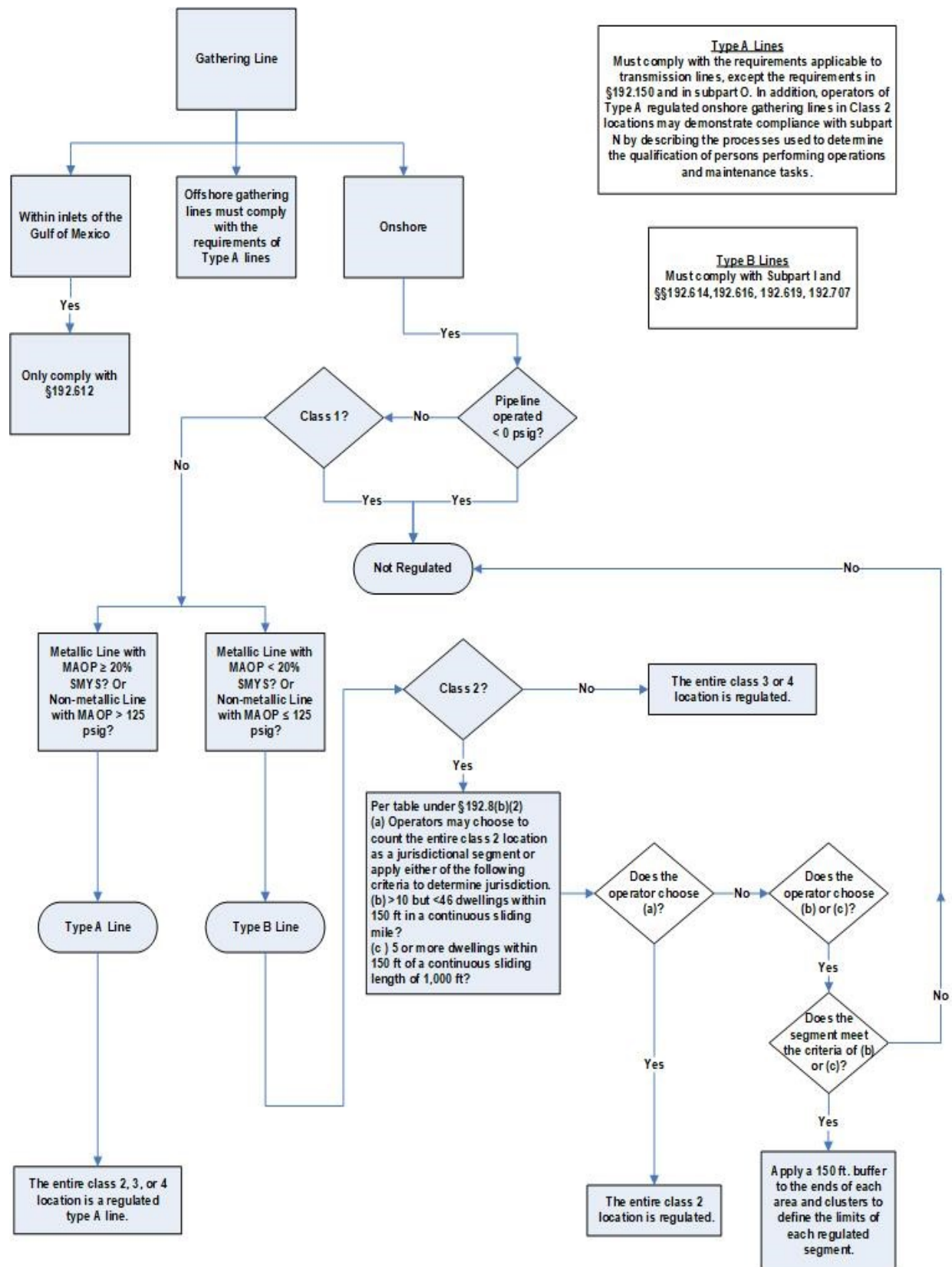


FIGURE 192.8C

§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 Amendments 192-129, 192-130 and 192-132.

- (a) See §192.1 and §192.8(c)(3) for gathering lines excluded from the provisions of Part 192.
- (b) See the "Glossary of Commonly Used Terms" under §192.3 for definition of "otherwise changed."
- (c) See §192.8 for regulated gathering line definitions.
- (d) 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.

Addendum 1, June 2022
Addendum 2, February 2023
Addendum 4, May 2024

[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).

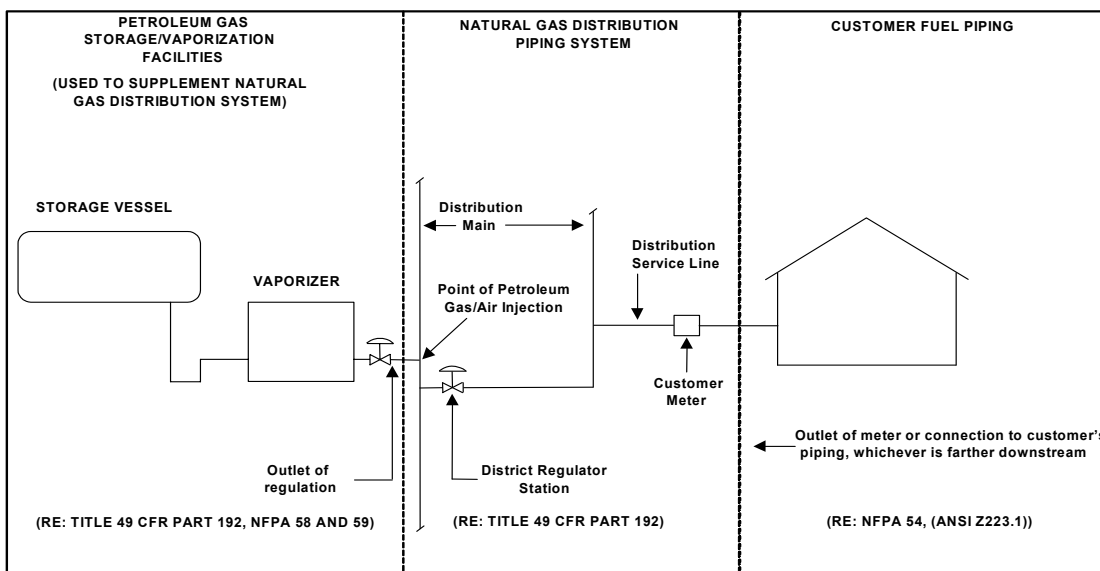


FIGURE 192.11A

Figure 192.11B depicts the standards applicable to pipeline systems for petroleum gas or petroleum gas/air mixtures, as described in §192.11(b).

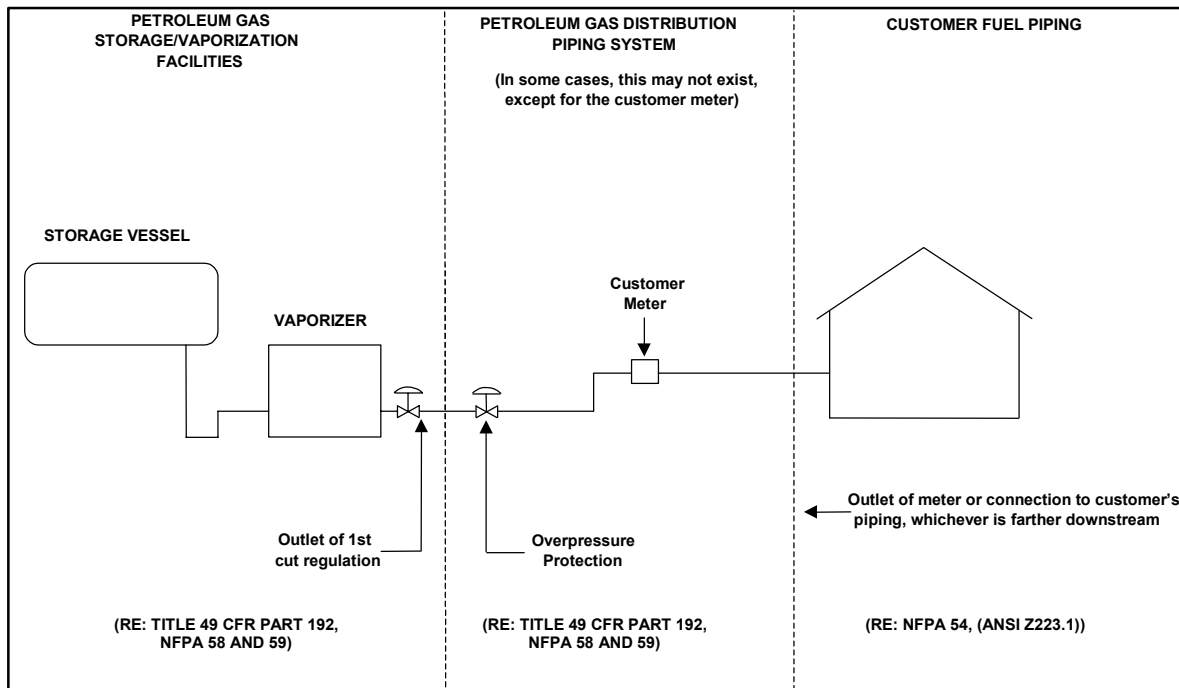


FIGURE 192.11B

1.2 Application of referenced codes.

- (a) General. The referenced NFPA Standards are applicable unless otherwise superseded, in whole or in part, by local governmental agency codes, rules, or regulations having jurisdiction.
- (b) Utility Gas Plant.
 - (i) A plant that stores and vaporizes LP-Gas for distribution that supplies either LP Gas or LP-Gas gas/air mixtures to a gas distribution system of 10 or more customers and is covered by NFPA 59.
 - (ii) All other plant and storage installations should comply with NFPA 58.
 - (iii) Jurisdiction under Part 192 is determined by §192.1(b)(5).
- (c) Distribution piping. This includes the pipeline from the outlet of the first pressure regulator to:
 - (1) The outlet of the customer meter or the connection to the customer's piping, whichever is farther downstream; or
 - (2) The connection to the customer's piping if there is no customer meter.
- (d) Customer piping. This includes all piping and facilities downstream of the distribution piping. These facilities are not included in the scope of 49 CFR 192. NFPA 54/ANSI Z223.1 (National Fuel Gas Code) referenced in Figures 192.11A and 192.11B is applicable unless otherwise superseded by the laws, regulations, or building codes of a local jurisdictional authority.

1.3 Conflict between referenced codes.

If the referenced NFPA Standards are silent or non-specific on a subject for which requirements exist in Part 192, then a conflict does not exist and operators should comply with Part 192 requirements.

1.4 Reference.

Operators of petroleum gas distribution and master meter systems may benefit from information

provided in the “Guidance Manual for Operators of LP Gas Systems” and “Operator Qualification Guidance Manual for Operators of LP Gas Systems” available at <https://www.phmsa.dot.gov/training/pipeline/guidance-manuals>.

2 PERSONNEL SAFETY

- (a) Operators should ensure that personnel who work with petroleum gases know the following.
- (1) Physical properties of these gases (e.g., heavier than air).
 - (2) Safe work practices for activities associated with petroleum gases that include the following.
 - (i) Handling.
 - (ii) Distributing.
 - (iii) Operation and maintenance.
- (b) For certain operations and maintenance tasks performed on a petroleum gas system, personnel may need to be qualified in accordance with Subpart N.

3 USE OF PLASTIC PIPE

See guide material under §§192.121 and 192.123.

4 LEAKAGE CONTROL GUIDELINES

For natural gas systems where petroleum gas or petroleum gas/air mixtures are used to supplement the natural gas, see Guide Material Appendix G-192-11.

For petroleum gas systems, see Guide Material Appendix G-192-11A.

§192.12

Underground natural gas storage facilities.

[Effective Date: 01/18/17]

Underground natural gas storage facilities must meet the following requirements:

(a) Each underground natural gas storage facility that uses a solution-mined salt cavern reservoir for gas storage constructed after July 18, 2017 must meet all requirements and recommendations of API RP 1170 (incorporated by reference, see § 192.7).

(b) Each underground natural gas storage facility that uses a solution-mined salt cavern reservoir for storage including those constructed not later than July 18, 2017 must meet the operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements and recommendations of API RP 1170, sections 9, 10, and 11 (incorporated by reference, see § 192.7) by January 18, 2018.

(c) Each underground natural gas storage facility that uses a depleted hydrocarbon reservoir or an aquifer reservoir for storage constructed after July 18, 2017 must meet all requirements and recommendations of API RP 1171 (incorporated by reference, see § 192.7).

(d) Each underground natural gas storage facility that uses a depleted hydrocarbon reservoir or an aquifer reservoir for gas storage, including those constructed not later than July 18, 2017 must meet the operations, maintenance, integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, site security, emergency response and preparedness, and recordkeeping requirements and recommendations of API RP 1171, sections 8, 9, 10, and 11 (incorporated by reference, see § 192.7) by January 18, 2018.

(e) Operators of underground gas storage facilities must establish and follow written procedures for operations, maintenance, and emergencies implementing the requirements of API RP 1170 and API RP 1171, as required under this section, including the effective dates as applicable, and incorporate such procedures into their written procedures for operations, maintenance, and emergencies established pursuant to § 192.605.

(f) With respect to the incorporation by reference of API RP 1170 and API RP 1171 in this section, the non-mandatory provisions (i.e., provisions containing the word “should” or other nonmandatory language) are adopted as mandatory provisions under the authority of the pipeline safety laws except when the operator includes or references written technical justifications in its program or procedural manual, described in paragraph (a)(5) of this section, as to why compliance with a provision of the recommended practice is not practicable and not necessary for safety with respect to specified underground storage facilities or equipment. The justifications for any deviation from any provision of API RP 1170 and API RP 1171 must be technically reviewed and documented by a subject matter expert to ensure there will be no adverse impact on design, construction, operations, maintenance, integrity, emergency preparedness and response, and overall safety and must be dated and approved by a senior executive officer, vice president, or higher office with responsibility of the underground natural gas storage facility. An operator must discontinue use of any variance where PHMSA determines and provides notice that the variance adversely impacts design, construction, operations, maintenance, integrity, emergency preparedness and response, or overall safety.

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

GUIDE MATERIAL

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

1 API RP 1170 AND API RP 1171 (See §192.7 for IBR)

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

2 REFERENCES

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

TABLE 192.12-1

National Standard	API RP 1170	API RP 1171
API Bulletin 5A2, <i>Bulletin on Thread Compounds for Casing, Tubing, and Line Pipe</i>	*	
API Bulletin E3, <i>Well Abandonment and Inactive Well Practices</i>		6.7.1
API Guidance Document HF1, <i>Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines</i>		6.5.3
API Guidance Document HF2, <i>Water Management Associated with Hydraulic Fracturing</i>		6.5.3
API Guidance Document HF3, <i>Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing</i>		6.5.3
API RP 5A3, <i>Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements</i>	8.4.2.6	
API RP 5A5, <i>Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe</i>	*	
API RP 5B1, <i>Gauging and Inspection of Casing, Tubing and Line Pipe Threads</i>	*	
API RP 5C1, <i>Recommended Practice for Care and Use of Casing</i>	8.4.2.5	

<i>and Tubing</i>		
API RP 10D-2, <i>Recommended Practice for Centralizer Placement and Stop-collar Testing</i>		6.4.5
API RP 10F, <i>Recommended Practice for Performance Testing of Cementing Float Equipment</i>	2, 7.6.1	
TABLE 192.12-1 (Continued)		
National Standard	API RP 1170	API RP 1171
API RP 13D, <i>Rheology and Hydraulics of Oil-well Drilling Fluids</i>	*	
API RP 14B, <i>Design, Installation, Repair and Operation of Subsurface Safety Valve Systems</i>		6.2.5
API RP 14E, <i>Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems</i>		6.3.5
API RP 49, <i>Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide</i>		6.8.1
API RP 51R, <i>Environmental Protection for Onshore Oil and Gas Production Operations and Leases</i>		5.5.1, 6.8.1
API RP 53, <i>Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells</i>	*	11.5.2
API RP 54, <i>Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations</i>		6.8.1, 11.5.2, 11.6.2
API RP 76, <i>Contractor Safety Management for Oil and Gas Drilling and Production Operations</i>		5.5.1, 6.8.1
API RP 1114, <i>Recommended Practice for the Design of Solution-Mined Underground Storage Facilities</i>	*	
API RP 1115, <i>Design and Operation of Solution-mined Salt Caverns Used for Liquid Hydrocarbon Storage</i>	*	
API Specification 5CT, <i>Specification for Casing and Tubing</i>	*	
API Specification 5DP, <i>Specification for Drill Pipe</i>	*	
API Specification 5L, <i>Specification for Line Pipe</i>	*	
API Specification 6A, <i>Specification for Wellhead and Christmas Tree Equipment</i>	*	6.2.1
API Specification 6D, <i>Specification for Pipeline Valves</i>	*	
API Specification 10A, <i>Specification for Cements and Materials for Well Cementing</i>	2, 7.6.1	6.4.2, 6.7.2
API Specification 14A, <i>Specification for Subsurface Safety Valve Equipment</i>		6.2.5
API Standard 65-2, <i>Isolating Potential Flow Zones during Well Construction</i>		6.4.5
API Standard 1104, <i>Welding of Pipelines and Related Facilities</i>	*	
API Technical Report 5C3, <i>Calculating Performance Properties of Pipe Used as Casing or Tubing</i>	2, 8.4.2.3	
API Technical Report 10TR1, <i>Cement Sheath Evaluation</i>		6.4.6
API Technical Report 10TR3, <i>Technical Report on Temperatures for API Cement Operating Thickening Time Tests</i>	*	
API Technical Report 10TR4, <i>Selection of Centralizers for Primary Cementing Operations</i>	*	6.4.5
ASTM C150/C150M, <i>Standard Specification for Portland Cement</i>		6.4.2, 6.7.2
ASTM D3740, <i>Standard Practice for Minimum Requirements for Agencies Engaged in Testing and/or Inspection of Soil and Rock as Used in Engineering Design and Construction</i>	5.4.2.1	
ASTM D3967, <i>Standard Test Method for Splitting Tensile Strength of Intact Rock Core Specimens</i>	2, 5.4.2.4	
ASTM D4543, <i>Standard Practices for Preparing Rock Core as Cylindrical Test Specimens and Verifying Conformance to</i>	2, 5.4.2.3	

<i>Dimensional and Shape Tolerances</i>		
ASTM D4645, <i>Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method</i>	2, 5.4.4	

TABLE 192.12-1 (Continued)		
National Standard	API RP 1170	API RP 1171
ASTM D7012, <i>Standard Test Methods for Compressive Strength and Elastic Moduli of Intact Rock Core Specimens under Varying States of Stress and Temperatures</i>	2, 5.4.2.5.1, 5.4.2.5.2, 5.4.2.5.3	
ASTM D7070, <i>Standard Test Methods for Creep of Rock Core Under Constant Stress and Temperature</i>	2, 5.4.2.6	
U.S. Bureau of Safety and Environmental Enforcement Report RLS0116, <i>Cement Plug Testing: Weight vs pressure Testing to Assess Viability of a Wellbore Seal between Zones</i>		6.7.2

* Standard referenced in API RP 1170, Section 2, but not associated with another particular section.

TABLE 192.12-1

- (b)—For additional guidance on managing risk for gas storage operations, the operator may refer to the following.
- (1) ISO 31000, *Risk Management – Guidelines*.
 - (2) ISO 31010, *Risk Management – Risk assessment techniques*.
 - (3) ISO 55000 Asset Management – PAS 55-1:2008, *Asset management – Part 1: Specification for the optimized management of physical assets*, PAS 55-2:2008 *Asset management – Part 2: Guidelines for the application of PAS 55-1*.
 - (4) ASME B31.8S, *Managing System Integrity of Gas Pipelines*.
 - (5) "Pipeline Risk Management Manual," W. Kent Muhlbauer, Gulf Publishing Company, ISBN: 0750675799.

3 COMPLIANCE DATES FOR EXISTING STORAGE FACILITIES

3.1 Solution-mined Salt Cavern Reservoirs

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

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

3.2 Depleted Hydrocarbon and Aquifer Reservoirs

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

- (a) Section 8, Risk Management for Gas Storage Operations, for operations, maintenance, and associated records.
- (b) Section 9, Integrity Demonstration, Verification, and Monitoring, for integrity demonstration and verification, monitoring, threat and hazard identification, assessment, remediation, and associated records.
- (c) Section 10, Site Security and Safety, Site Inspections, and Emergency Preparedness and Response, for site security, emergency response and preparedness, and associated records.
- (d) Section 11, Procedures and Training, and associated records.

§192.13

What general requirements apply to pipelines regulated under this part?

[Effective Date: 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

This guide material is under review following Amendment 192-132.

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 its 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 192-132.

1 NOTIFICATION INFORMATION

Operators are required to use an OPID in any notification to PHMSA (§191.22(d)).

See the following code sections for information regarding specific notification requirements.

- (a) Section 192.506(b) for notification requirements concerning spike testing.
- (b) Sections 192.607(e)(4) and 192.607(e)(5) for notification requirements concerning material verification
- (c) Sections 192.624(c)(2)(iii) and 192.624(c)(6) for notification requirements concerning MAOP reconfirmation.
- (d) Section 192.632(b)(3) for notification requirements concerning Engineering Critical Assessment.
- (e) Sections 192.712(d)(3)(iv) and 192.712(e)(2)(i)(E) for notification requirements concerning analysis of predicted failure pressure.
- (f) Section 192.805(i) for notification of significant modifications to OQ program.
- (g) Section 192.909, when the operator makes substantial changes to the integrity management program. Notifications should include the description and reason for the program or schedule change.
- (h) Sections 192.710, 192.921, and 192.937, when the operator makes use of other technologies for assessment. Notifications should include the following information.
 - (1) Description and rationale for new technology.

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Addendum 2, February 2023

Addendum 4, May 2024

- (2) Where the technology will be used.
- (3) Procedures for applying the technology.
- (4) Procedures for qualifying persons performing the assessment and analyzing the results.
- (i) Section 192.927, when ICDA is used to assess a covered segment with an electrolyte present in the gas stream (wet gas ICDA). Notifications must include a plan demonstrating how ICDA effectively addresses internal corrosion.
- (j) Section 192.933(a)(1), when the operator cannot meet the schedule and cannot provide safety through temporary pressure reduction. Notifications should include the following information.
 - (1) Reason why the schedule cannot be met or temporary pressure reduction cannot be implemented.
 - (2) How public safety will be maintained.
- (k) Section 192.933(a)(2), when a pressure reduction exceeds 365 days. Notifications must include the following information.
 - (1) Reason for remediation delays.
 - (2) Technical justification that pressure reduction is sufficient for maintaining public safety.

2 STATE NOTIFICATION

Where PHMSA-OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that state, an operator must also notify the state pipeline safety agency (§192.18(b)). A reference for state contacts is available at www.napsr.org.

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SUBPART B MATERIALS

§192.51

Scope.

[Effective Date: 11/12/70]

This subpart prescribes minimum requirements for the selection and qualification of pipe and components for use in pipelines.

GUIDE MATERIAL

1 GENERAL

Operators designing and installing gathering lines that are not regulated at the time of installation should be aware of the materials of construction in case the pipeline becomes regulated in the future and whether the materials used were manufactured under a listed specification.

Examples of non-listed materials include the following.

- (a) Polyethylene manufactured according to ASTM F2619 and API 15LE.
- (b) Spoolable composite materials manufactured in accordance with API 15S.
- (c) Mechanical interference fit joint and other non-qualified joints and joining systems.

2 MATERIALS

Repairs or replacements on regulated segments of gathering lines must be performed using materials manufactured to a listed specification (§192.53).

3 SPECIAL PERMIT (WAIVER)

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

If a segment of previously non-regulated gathering line becomes regulated, PHMSA-OPS or the state agency with jurisdiction may 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.

§192.53

General.

[Effective Date: 11/12/70]

Materials for pipe and components must be —

- (a) Able to maintain the structural integrity of the pipeline under temperature and other environmental conditions that may be anticipated;**
- (b) Chemically compatible with any gas that they transport and with any other material in the pipeline with which they are in contact; and**
- (c) Qualified in accordance with the applicable requirements of this subpart.**

GUIDE MATERIAL

1 FRACTURE TOUGHNESS REQUIREMENTS

- (a) Seam-welded steel pipe, 20 inches and larger in diameter and with SMYS of 52,000 psi or higher to be installed in transmission lines and Type A gathering lines to operate at 40% or more of SMYS and at operating pipe temperature less than 60 °F, should exhibit sufficient notch ductility at the operating pipe temperature. Compliance with either the Charpy impact or drop weight test criteria specified in SR5 or SR6 of API Spec 5L (see listing in §192.7, not IBR for §192.53) is sufficient evidence of such ductility when impact tests are made at or below the design pipe temperature.
- (b) For special installations (e.g., compressor station piping, small replacement sections), the notch ductility should be determined by appropriate criteria, which may include those specified in SR5 or SR6 of API Spec 5L.
- (c) Notch ductility tests are not necessary on pipe for small special installations (e.g., new highway crossings and extensions of compressor station headers) where pipe to be installed (i) is on hand from earlier purchases to specifications at least equal to those applicable at the time of the original installation, or (ii) is a short portion of a larger order that exhibited adequate notch ductility.

2 SOUR GAS COMPATIBILITY

- (a) See guide material under §192.475 for internal corrosion considerations.
- (b) NACE MR0175 contains guidelines for selecting materials for valves used in sour gas service. The use of controlled hardness techniques and the use of alternate materials, as described in NACE MR0175, may be effective for other components in controlling sulfide stress cracking. The use of controlled hardness techniques should not be considered a solution to other problems involving H₂S.

§192.55

Steel pipe.

[Effective Date: 08/06/15]

- (a) **New steel pipe is qualified for use under this part if —**
 - (1) It was manufactured in accordance with a listed specification;
 - (2) It meets the requirements of —
 - (i) Section II of Appendix B to this part; or
 - (ii) If it was manufactured before November 12, 1970, either section II or III of Appendix B to this part; or
 - (3) It is used in accordance with paragraph (c) or (d) of this section.
- (b) **Used steel pipe is qualified for use under this part if —**
 - (1) It was manufactured in accordance with a listed specification and it meets the requirements of paragraph II-C of Appendix B to this part;
 - (2) It meets the requirements of —
 - (i) Section II of Appendix B to this part; or
 - (ii) If it was manufactured before November 12, 1970, either section II or III of Appendix B to this part;
 - (3) It has been used in an existing line of the same or higher pressure and meets the requirements of paragraph II-C of Appendix B to this part; or
 - (4) It is used in accordance with paragraph (c) of this section.
- (c) **New or used steel pipe may be used at a pressure resulting in a hoop stress of less than 6,000 p.s.i. (41 MPa) where no close coiling or close bending is to be done, if visual examination indicates**

that the pipe is in good condition and that it is free of split seams and other defects that would cause 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.

<p>§192.57 (Removed and reserved.)</p> <p style="text-align: right;"><i>[Effective Date: 03/08/89]</i></p>
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<p>§192.59 Plastic pipe.</p> <p style="text-align: right;"><i>[Effective Date: 01/22/19]</i></p>
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- (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]

§192.63

Marking of materials.

[Effective Date: 01/22/19]

(a) Except as provided in paragraph (d) and (e) of this section, each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured.

(b) Surfaces of pipe and components that are subject to stress from internal pressure may not be field die stamped.

(c) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.

(d) Paragraph (a) of this section does not apply to items manufactured before November 12, 1970, that meet all of the following:

(1) The item is identifiable as to type, manufacturer, and model.

(2) Specifications or standards giving pressure, temperature, and other appropriate criteria for the use of items are readily available.

(e) All plastic pipe and components must also meet the following requirements:

(1) All markings on plastic pipe prescribed in the listed specification and the requirements of paragraph (e)(2) of this section must be repeated at intervals not exceeding two feet.

(2) Plastic pipe and components manufactured after December 31, 2019 must be marked in accordance with the listed specification.

(3) All physical markings on plastic pipelines prescribed in the listed specification and paragraph (e)(2) of this section must be legible until the time of installation.

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-31, 43 FR 13880, Apr. 3, 1978 with Amdt. 192-31A, 43 FR 21462, May 18, 1978; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988 with Amdt. 192-61A, 54 FR 32641, Aug. 9, 1989; Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-76, 61 FR 26121, May 24, 1996 with Amdt. 192-76 Correction, 61 FR 36825, July 15, 1996; 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.

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

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

Note: The HDB expresses the long-term strength of a thermoplastic material in terms of a series of standard strength categories (e.g., 1600 psi, 1250 psi, 1000 psi) which have been established in

accordance with ASTM D2837. Specific HDBs can be obtained from the manufacturer and from the Plastics Pipe Institute (PPI).

- (b) Thermoplastic pipe manufactured prior to August 16, 1978 may not be marked with the appropriate code letters for elevated temperature operation. Operators who have installed such pipe should take proper precautions to ensure the pipe is used only within the actual temperature and stress limits for which it was tested and qualified. See §192.123(b)(2).
- (c) Marking requirements for PE pipe manufactured after March 6, 2015 are described in ASTM D2513-09a. All other new installations of thermoplastic materials must meet the ASTM D2513-87 (see §192.7 for IBR) marking requirements (§192.63(a)).

§192.65

Transportation of pipe.

[Effective Date: 10/01/15]

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

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

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

[Amdt. 192-12, 38 FR 4760, Feb. 22, 1973; Amdt. 192-17, 40 FR 6345, Feb. 11, 1975 with Amdt. 192-17 Correction, 40 FR 24361, June 6, 1975; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

Pipe transported by railroad before November 12, 1970, may have been qualified for use by pressure testing prior to October 1, 2015 (refer to Amendment 192-120), so the operator should retain records of those tests.

§192.67

Records: Material properties

[Effective Date: 07/01/20]

(a) For steel transmission pipelines installed after [July 1, 2020, an operator must collect or make, and retain for the life of the pipeline, records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and

chemical composition of materials for pipe in accordance with §§ 192.53 and 192.55. Records must include tests, inspections and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.

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

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

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

GUIDE MATERIAL

Note: In Amendment 192-125, former §192.67 language titled “Storage and handling of plastic pipe and associated components” was renumbered to §192.69.

1 SCOPE

- (a) The material records requirements under §192.67 apply to steel pipelines in transmission, offshore, and Type A gathering systems (see §192.9(c)).
- (b) Operators of Type B and Type C gathering lines are exempt from the requirements of this section (see §192.9(d) and (e)).
- (c) Operators of distribution systems, Type B gathering lines, and Type C gathering lines might consider the following guidance for records.

2 RECORDS

- (a) The operator should review the pipe specifications used at the time of manufacture to identify the required records.
- (b) The operators should retain records beyond the minimum requirements of the manufacturing standard (e.g., contract specifications, manufacturing inspection records, manufacturing process).
- (c) When pipe material records identified under §192.67(b) are discovered or generated through a material properties verification process, they must be retained for the life of the pipeline. These records should be included in the operator’s permanent documentation to support the determination of the MAOP and included in the threat analysis of the operator’s integrity management program.
- (d) Operators should consider reviewing past project documentation for records that meet the minimum requirements of this section.
- (e) Discovered records should be reviewed for accuracy and relevancy. Historical material records and field inspection records should be confirmed with other complementary or supporting documents, when applicable.
- (f) Material records should be used to select or develop appropriate welding procedures.
- (g) Records can be maintained at a central location or at multiple locations for the operational life of the pipe.
- (h) Records can be maintained either electronically, as paper copies, or in any other appropriate format.
- (i) Operators should consider implementing recommendations from API RP 5MT, “Pipeline Inspection Documents for Material Traceability and Electronic Test Reports.”
- (j) See guide material under §192.205 for records on component materials.
- (k) See guide material under §§192.607 and 192.624 for pipelines lacking complete material records.

§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 listing in §192.7, not IBR for §192.103).

- (b) API RP 5LW, "Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels" (see listing in §192.7, not IBR for §192.103).
- (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:

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

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 °F (482 °C) at any time or is held above 600 °F (316 °C) 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.

2 NOMINAL OUTSIDE DIAMETER

The nominal outside diameter (D) used in the design formula is listed in Table 192.105i for nominal pipe sizes (NPS) 12 and less. For pipe greater than NPS 12, the nominal pipe size and nominal outside diameter are the same. Pipe may be ordered by the nominal pipe size; however, the nominal outside diameter is required in the design formula for steel pipe.

PIPE SIZE AND OUTSIDE DIAMETER ^{1,2}			
Nominal Pipe Size (NPS)	Nominal Outside Diameter (D) (Inches)	Nominal Pipe Size (NPS)	Nominal Outside Diameter (D) (Inches)
1/8	0.405	2 1/2	2.875
1/4	0.540	3	3.500
3/8	0.675	3 1/2	4.000
1/2	0.840	4	4.500
3/4	1.050	5	5.563
1	1.315	6	6.625
1 1/4	1.660	8	8.625
1 1/2	1.900	10	10.750
2	2.375	12	12.750

¹ Values obtained from ASTM A53 for steel pipe and from ASTM D2513 for plastic pipe.
² This table applies to steel, plastic, and some types of cast iron pipe.

TABLE 192.105i

3 DESIGN PRESSURE OF PIPE WITH UNKNOWN VARIABLES

When reviewing the design pressure for a conversion under §192.14 or an uprating of steel pipe under Subpart K, and the design pressure of pipe cannot be calculated because one or more of the variables is unknown, a value may be determined in accordance with §192.619(a)(1).

<p>§192.107 Yield strength (S) for steel pipe.</p> <p style="text-align: right;"><i>[Effective Date: 07/13/98]</i></p>
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(a) For pipe that is manufactured in accordance with a specification listed in section I of Appendix B of this part, the yield strength to be used in the design formula in §192.105 is the SMYS stated in the listed specification, if that value is known.

(b) For pipe that is manufactured in accordance with a specification not listed in section I of Appendix B to this part or whose specification or tensile properties are unknown, the yield strength to be used in the design formula in §192.105 is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of Appendix B to this part, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.

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

[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; 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; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL

See Guide Material Appendix G-192-2.

2 REFERENCES

If the yield strength of in-service pipe is undetermined, the documents listed below may be helpful to estimate the lower bound of the yield strength. See §190.341 for application content and requirements for a special permit (waiver) from PHMSA-OPS to use the technology presented in the following references.

- (a) ASME CRTD Vol. 57, "Determining the Yield Strength of In-Service Pipe."
- (b) ASME CRTD-91, "Applications Guide for Determining the Yield Strength of In-Service Pipe by Hardness Evaluation."

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

§192.109

Nominal wall thickness (t) for steel pipe.

[Effective Date: 07/13/98]

(a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

(b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need be measured. The thickness of the lengths that are not measured must be verified by applying a gage set to the minimum thickness found by the measurement. The nominal wall thickness to be used in the design formula in §192.105 is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches (508 millimeters) in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches (508 millimeters) or more in outside diameter.

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

GUIDE MATERIAL

No guide material necessary.

§192.111

Design factor (*F*) for steel pipe.

[Effective Date: 08/01/77]

(a) Except as otherwise provided in paragraphs (b), (c), and (d) of this section, the design factor to be used in the design formula in §192.105 is determined in accordance with the following table:

Class Location	Design factor (<i>F</i>)
1	0.72
2	0.60
3	0.50
4	0.40

(b) A design factor of 0.60 or less must be used in the design formula in §192.105 for steel pipe in Class 1 locations that:

- (1) Crosses the right-of-way of an unimproved public road, without a casing;
- (2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;
- (3) Is supported by a vehicular, pedestrian, railroad, or pipeline bridge; or
- (4) Is used in a fabricated assembly, (including separators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

(c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §192.105 for uncased steel pipe that crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

(d) For Class 1 and Class 2 locations, a design factor of 0.50, or less, must be used in the design formula in §192.105 for —

- (1) Steel pipe in a compressor station, regulating station, or measuring station; and
- (2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976]

GUIDE MATERIAL

1 USE OF DESIGN FACTOR (F) FOR STEEL PIPE IN §192.111

Design factors no greater than those listed below are to be used in the design formula in § 192.105

Installation Condition	Class Location			
	1	2	3	4
For pipelines subject to §192.111(a) only:				
For pipelines with MAOP established under §192.619	0.72	0.60	0.50	0.40
For pipelines with MAOP established under §192.620	0.80	0.67	0.56	N/A
For pipelines subject to §192.111(b), (c), or (d) with MAOP established under §192.619, or pipelines installed after December 22, 2008 with MAOP established according to §192.620 (See Note 4)				
Crossings without casings of:				
Private roads (See Note 1)	0.72	0.60	0.50	0.40
The rights-of-way of unimproved public roads	0.60	0.60	0.50	0.40
The rights-of-way of hard surfaced roads, highways, public streets, railroads	0.60	0.50	0.50	0.40
Crossings with casings of:				
Private roads (See Note 1)	0.72	0.60	0.50	0.40
The rights-of-way of unimproved public roads	0.72	0.60	0.50	0.40
The rights-of-way of hard surfaced roads, highways, public streets, railroads	0.72	0.60	0.50	0.40
Parallel encroachments on:				
Private roads (See Note 1)	0.72	0.60	0.50	0.40
The rights-of-way of unimproved public roads	0.72	0.60	0.50	0.40
The rights-of-way of hard surfaced roads, highways, public streets, railroads	0.60	0.60	0.50	0.40
Pipelines on bridges	0.60	0.60	0.50	0.40
Fabricated assemblies (See Note 2)	0.60	0.60	0.50	0.40
Compressor, regulating, or measuring station piping	0.50	0.50	0.50	0.40
Pipe, including pipe risers, on platforms located offshore (See Note 3)	0.50	N/A	N/A	N/A
Pipe, including pipe risers, on platforms located in inland navigable waters (See Note 3)	0.50	0.50	0.50	0.40
For pipelines subject to §192.111(b), (c), or (d) installed prior to December 22, 2008 with MAOP established under §192.620 (See Note 4)				
Crossing without casings of:				
Private roads (See Note 1)	0.67	0.56	0.50	N/A

The rights-of-way of unimproved public roads	0.67	0.56	0.50	N/A
The rights-of-way of hard surfaced roads, highways, public streets, railroads	0.67	0.56	0.50	N/A
Crossings with casings of:				
Private roads (See Note 1)	0.67	0.56	0.50	N/A
The rights-of-way of unimproved public roads	0.67	0.56	0.50	N/A
The rights-of-way of hard surfaced roads, highways, public streets, railroads	0.67	0.56	0.50	N/A
Parallel encroachments on:				
Private roads (See Note 1)	0.67	0.56	0.50	N/A

The rights-of-way of unimproved public roads	0.67	0.56	0.50	N/A
The rights-of-way of hard surfaced roads, highways, public streets, railroads	0.67	0.56	0.50	N/A
Pipelines on bridges	0.67	0.56	0.50	N/A
Fabricated assemblies (See Note 2)	0.67	0.56	0.50	N/A
Compressor, regulating, or measuring station piping	0.56	0.56	0.50	N/A
Pipe, including pipe risers, on platforms located offshore (See Note 3)	0.56	N/A	N/A	N/A
Pipe, including pipe risers, on platforms located in inland navigable waters (See Note 3)	0.56	0.50	0.50	0.40

Notes:

1. "Private roads" are roads that are not intended for use by the general public and over which travel and transportation are restricted.
2. Section 192.165(b)(3) requires that liquid separators located in compressor stations and constructed of pipe and fittings without internal welding must be fabricated with a design factor (F) of 0.40, or less.
3. Steel pipe risers should be considered to be the vertical or near vertical portion of a pipeline between the platform piping and the pipeline at or below the water bottom, including a length of pipe at least 5 pipe diameters beyond the bottom elbow, bend, or fitting. Due to the wide variety of configurations, the exact location of the transition between pipeline, pipe riser, and platform piping must be selected on a case-by-case basis.
4. The design factors for alternative MAOP calculated under §192.620 may only be used if the facility design complies with the additional requirements under §192.112.

TABLE 192.111i

**2 DESIGN OF UNCASSED PIPELINE CROSSINGS OF HIGHWAYS AND RAILROADS
(§192.111(b)(1), (b)(2) and (c))**

See Guide Material Appendix G-192-15.

§192.112

Additional design requirements for steel pipe using alternative maximum allowable operating pressure.

[Effective Date: 10/01/15]

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure (MAOP) calculated under §192.620, a segment must meet the following additional design requirements. Records for alternative MAOP must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this design issue:	The pipeline segment must meet these additional requirements:
(a) General standards for the steel pipe.	<p>(1) The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment.</p> <p>(2) The carbon equivalents of the steel used for pipe must not exceed 0.25 percent by weight, as calculated by the Ito-Bessyo formula (Pcm formula) or 0.43 percent by weight, as calculated by the International Institute of Welding (IIW) formula.</p> <p>(3) The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness or other mitigative measures must prevent denting and ovality anomalies during construction, strength testing and anticipated operational stresses.</p> <p>(4) The pipe must be manufactured using API Spec 5L, product specification level 2 (incorporated by reference, see §192.7) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this section.</p>
(b) Fracture control	<p>(1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with:</p> <ul style="list-style-type: none"> (i) API Spec 5L (incorporated by reference, see §192.7); or (ii) American Society of Mechanical Engineers (ASME) B31.8 (incorporated by reference, see §192.7); and (iii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Spec 5L, product specification level 2 or ASME B31.8 (incorporated by reference, see §192.7). <p>(2) Fracture control must:</p> <ul style="list-style-type: none"> (i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline; (ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters;

<p>To address this design issue:</p>	<p>The pipeline segment must meet these additional requirements:</p>
<p>(b) Fracture control (continued)</p>	<p>(iii) Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths; and</p> <p>(iv) Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Specification 5L (incorporated by reference, see §192.7) and ensures ductile fracture and arrest with the following exceptions:</p> <p>(A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent minimum shear area for any single test on each heat of steel; and</p> <p>(B) The results of the drop weight test prescribed in SR6 must indicate 80 percent average shear area with a minimum single test result of 60 percent shear area for any steel test samples. The test results must ensure a ductile fracture and arrest.</p> <p>(3) If it is not physically possible to achieve the pipeline toughness properties of paragraphs (b)(1) and (2) of this section, additional design features, such as mechanical or composite crack arrestors and/or heavier walled pipe of proper design and spacing, must be used to ensure fracture arrest as described in paragraph (b)(2)(iii) of this section.</p>
<p>(c) Plate/coil quality control</p>	<p>(1) There must be an internal quality management program at all mills involved in producing steel, plate, coil, skelp, and/or rolling pipe to be operated at alternative MAOP. These programs must be structured to eliminate or detect defects and inclusions affecting pipe quality.</p> <p>(2) A mill inspection program or internal quality management program must include (i) and either (ii) or (iii):</p> <p>(i) An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after December 22, 2008, the test must be done in accordance with ASTM A578/A578M Level B, or API Spec 5L Paragraph 7.8.10 (incorporated by reference, see §192.7) or equivalent method, and either</p> <p>(ii) A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on the first or second slab of each sequence graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent; or</p>

To address this design issue:	The pipeline segment must meet these additional requirements:
(c) Plate/coil quality control (continued)	<p>(iii) A quality assurance monitoring program implemented by the operator that includes audits of: (a) all steelmaking and casting facilities, (b) quality control plans and manufacturing procedure specifications, (c) equipment maintenance and records of conformance, (d) applicable casting superheat and speeds, and (e) centerline segregation monitoring records to ensure mitigation of centerline segregation during the continuous casting process.</p>
(d) Seam quality control	<p>(1) There must be a quality assurance program for pipe seam welds to assure tensile strength provided in API Spec 5L (incorporated by reference, see §192.7) for appropriate grades.</p> <p>(2) There must be a hardness test, using Vickers (Hv10) hardness test method or equivalent test method, to assure a maximum hardness of 280 Vickers of the following:</p> <p>(i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and</p> <p>(ii) For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal).</p> <p>(3) All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing.</p>
(e) Mill hydrostatic test	<p>(1) All pipe to be used in a new pipeline segment installed after October 1, 2015, must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds.</p> <p>(2) Pipe in operation prior to December 22, 2008, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds.</p> <p>(3) Pipe in operation on or after December 22, 2008, but before October 1, 2015, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. The test pressure may include a combination of internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by "ANSI/API Spec 5L" (incorporated by reference, see §192.7).</p>

To address this design issue:	The pipeline segment must meet these additional requirements:
(f) Coating	<p>(1) The pipe must be protected against external corrosion by a non-shielding coating.</p> <p>(2) Coating on pipe used for trenchless installation must be non-shielding and resist abrasions and other damage possible during installation.</p> <p>(3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.</p>
(g) Fittings and flanges	<p>(1) There must be certification records of flanges, factory induction bends and factory weld ells. Certification must address material properties such as chemistry, minimum yield strength and minimum wall thickness to meet design conditions.</p> <p>(2) If the carbon equivalents of flanges, bends and ells are greater than 0.42 percent by weight, the qualified welding procedures must include a pre-heat procedure.</p> <p>(3) Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP.</p>
(h) Compressor stations	<p>(1) A compressor station must be designed to limit the temperature of the nearest downstream segment operating at alternative MAOP to a maximum of 120 degrees Fahrenheit (49 degrees Celsius) or the higher temperature allowed in paragraph (h)(2) of this section unless a long-term coating integrity monitoring program is implemented in accordance with paragraph (h)(3) of this section.</p> <p>(2) If research, testing and field monitoring tests demonstrate that the coating type being used will withstand a higher temperature in long-term operations, the compressor station may be designed to limit downstream piping to that higher temperature. Test results and acceptance criteria addressing coating adhesion, cathodic disbondment, and coating condition must be provided to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operating above 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.</p>

To address this design issue:	The pipeline segment must meet these additional requirements:
(h) Compressor stations (continued)	(3) Pipeline segments operating at alternative MAOP may operate at temperatures above 120 degrees Fahrenheit (49 degrees Celsius) if the operator implements a long-term coating integrity monitoring program. The monitoring program must include examinations using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or an equivalent method of monitoring coating integrity. An operator must specify the periodicity at which these examinations occur and criteria for repairing identified indications. An operator must submit its long-term coating integrity monitoring program to each PHMSA pipeline safety regional office in which the pipeline is located for review before the pipeline segments may be operated at temperatures in excess of 120 degrees Fahrenheit (49 degrees Celsius). An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.

[Issued by RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008; Amdt. 192-111, 74 FR 62503, Nov. 30, 2009; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

1 GENERAL

New or existing pipelines that will operate at an alternative maximum allowable operating pressure (MAOP) have prescribed manufacturing and documentation requirements for steel pipe, fittings, and flanges (§192.112). Documentation of the following factors support eligibility for an alternative MAOP.

- (a) General steel pipe standards.
 - (1) Material chemistry of steel plate, skelp, or coil.
 - (2) Use of clean steel manufacturing.
 - (3) Control of carbon and micro-alloying elements.
 - (4) Ovality limits.
 - (5) Rolling, temperature control, and cooling practices.
 - (6) Adherence to API Spec 5L-Product Specification Level 2 (PSL 2) – see §192.7 for IBR.
- (b) Fracture control.
- (c) Plate or coil quality control.
- (d) Seam quality control.
- (e) Mill hydrostatic test.
- (f) Pipe coating.

2 METALLURGY

- (a) Micro-alloyed steel is a type of steel that contains small amounts (0.05 to 0.15%) of alloying elements. Standard alloying elements include niobium, vanadium, titanium, molybdenum, zirconium, boron, and rare-earth metals. Varying the amounts of alloying elements and the form of their presence in the steel (solute elements or precipitated phase) controls qualities of the steel, such as hardness, ductility, and tensile strength.
- (b) Steel with fine grains within its microstructure has higher strength, improved toughness, less distortion during heat treatment, and a lower tendency to develop quench cracks in comparison to steel with coarse grains. Fine-grained steels also have very good resistance to crack initiation and propagation.
- (c) Fully killed steel is made by completely deoxidizing the molten steel before it is cast. Oxygen trapped within the molten metal during the steel making process can form carbon monoxide bubbles. Carbon monoxide bubbles can cause porosity, act as an initiation point for failures, and inhibit grain growth.
- (d) Calcium is used during the steel manufacturing process to control the shape of inclusions within the steel.
- (e) Carbon equivalent is a parameter used to assess the weldability of a steel grade. For higher carbon equivalent values, greater care is needed during pre- and post-heat treatment. The carbon equivalent must not exceed 0.25% by weight as calculated by the Ito-Bessyo formula (Pcm formula), or 0.43% by weight as calculated by the International Institute of Welding (IIW) formula (§192.112(a)(2)).
- (f) Toughness of a material is its ability to absorb energy and deform plastically before fracturing. A tough steel will absorb more energy before fracturing than weak or brittle steel (depending on whether the material yielded or not).
- (g) Hardness of a material is a measure of its resistance to deformation. It describes how much energy it takes to deform (e.g., stretch, compress, bend). A hard steel takes more energy to deform than does a soft steel.

3 FRACTURE CONTROL

3.1 General.

A propagating ductile fracture is an interactive phenomenon between gas decompression and crack propagation. As a crack is initiated, the gas escapes from the pipeline and starts a decompression wave in the pipeline. A crack may then follow the wave until it is arrested. The driving force limiting crack propagation is the energy of the gas escaping through a fracture, thereby reducing pressure. The fracture growth stops once the stress, due to internal pipeline pressure, reaches equilibrium with or falls below the stress that is necessary to maintain crack propagation. Otherwise, it will continue to, and end at, a potential arrest point (e.g., valve, end of the pipeline).

3.2 Design considerations.

- (a) Fracture control design for steel pipelines may consider the following factors.
 - (1) Crack initiation and propagation in the parent pipe material and seam welds.
 - (2) Likelihood of fractures in girth welds and fittings.
 - (3) Mechanical damage (e.g., dents, gouges).
 - (4) Range of operating temperatures.
 - (5) Gas composition.
 - (6) Design stresses.
 - (7) Pipe grade.
 - (8) Range of operating pressures.
- (b) To obtain resistance to fracture initiation in the parent pipe, the steel pipe should have sufficient toughness to be dominated by plastic collapse in the event of a failure.
- (c) The ductile crack arrest properties of a steel pipeline should control the pipe material's ability to resist the initiation and propagation of cracks. The levels of sulfur, phosphorus, and nitrogen used

during the manufacturing of steel pipe should be minimized as these elements can detrimentally affect ductility and crack resistance.

- (d) Fracture velocity is stress dependent; higher design stress produces higher velocity for the propagation of a fracture. As pressure within the pipeline falls after rupture, the fracture velocity will likewise fall.
- (e) Fracture velocity is toughness dependent; increased toughness results in lower fracture velocity.
- (f) Fracture control may also be achieved within a pipeline by using the following.
 - (1) Pipe segments designed with heavier wall thickness and proper spacing.
 - (2) Pipe seams offset from joint to joint.
 - (3) Composite reinforced pipe.
 - (4) Steel grouted sleeves.

3.3 Methodologies to assess fracture control.

For evaluating the ability of a particular PSL 2 steel to resist crack initiation and propagation, see the following methodologies in ASME B31.8 and API Spec 5L – Annex G (see §192.7 for IBR for both). Through the use of these methodologies, the minimum Charpy impact values can be established as a measure of required toughness for pipelines operating at an alternative MAOP.

- (a) Battelle Two-Curve Model.
- (b) American Iron and Steel Institute (AISI).
- (c) British Gas.
- (d) British Steel Corporation.
- (e) European Pipeline Research Group (EPRG).
- (f) Full-scale burst test.

3.4 Charpy Impact Test.

- (a) The Charpy impact test, also known as the Charpy V-notch test, is a standardized high strain-rate test that determines the amount of energy absorbed by a material during fracture. This absorbed energy is a measure of material toughness and may act as a tool to study temperature-dependent ductile-brittle transition. The quantitative result of the impact test measures the energy needed to fracture a material and can be used to determine a material's toughness, yield strength, and ductility.
- (b) If the material breaks on a flat plane, the fracture is brittle. If the material breaks with jagged edges or shear lips, the fracture is ductile. Typically a material does not break in just one way. Comparison of the jagged to flat surface areas of the fracture provides an estimate of the percentage of ductile and brittle fracture.

3.5 Drop Weight Tear Test (DWTT).

Drop weight tear tests are widely used in the steel industry to determine the occurrence of, and fracture resistance against, propagating fractures in pipe steels over the temperature range where the fracture mode changes from brittle to ductile.

4 QUALITY MANAGEMENT PROGRAM

4.1 General.

Materials and manufacturing quality management programs may be used to ensure that the steel pipe manufactured for service at an alternative MAOP adheres to its metallurgical, chemical, and dimensional specifications. A quality management program might include the following.

- (a) Pipe manufacturing mill qualification.
- (b) Pipe standard, specifications, and contracting agreements.
- (c) Pipe manufacturing procedure specification (MPS) review for determining whether the pipe steel meets the MPS.
- (d) Surveillance and monitoring during the manufacturing process.
- (e) Records and documentation that validate adherence to material and manufacturing specifications.

4.2 *Purchase order guidelines.*

Purchase orders issued by operators for manufacturing the pipe that will have an alternative MAOP might include the following specifications.

- (a) Quantity of pipe.
- (b) Pipe type (e.g., grade, seam type, outside diameter, wall thickness).
- (c) Pipe manufacturing standard and process.
- (d) Chemical composition.
- (e) Carbon equivalent limits.
- (f) Diameter and out-of-round tolerances.
- (g) Pipe length tolerances.
- (h) Type of end face.
- (i) Weldability data.
- (j) Quality control testing requirements.
- (k) Manufacturing and testing documentation.
- (l) Coating requirements.
- (m) Pipe markings.

4.3 *Manufacturing procedure specifications.*

Manufacturing procedure specifications should be reviewed for deviations during the production and rolling of steel plate or coil to ensure adherence to the requirements of API Spec 5L– PSL 2 (see §192.7 for IBR). Small deviations in the steel rolling schedule parameters can affect the final mechanical properties of the steel. A review should include the following.

- (a) Mechanical, metallurgical, and chemical composition tests.
- (b) Heating and rolling temperatures.
- (c) Temperature control during rolling process.
- (d) Inspection methods and reports.
- (e) Deformation tool results.
- (f) Hydrostatic test failures.

4.4 *Ultrasonic testing for plate or coil quality control.*

Ultrasonic flaw detection is a non-destructive inspection technique which uses the principles of sound propagation on steel plates or coils to determine the location, shape, and size of flaws. This information plays an important role in fracture mechanics where the maximum safe stresses can be calculated for a given flaw size and location. For a given operating stress and type of flaw, the maximum flaw size that can be tolerated safely can also be determined.

Steel pipe flaws that can be detected by ultrasonic testing include the following.

- (a) Cracks.
- (b) Porosity.
- (c) Laminations.
- (d) Corrosion.
- (e) Inclusions.

4.5 *Macro Etch Test.*

The Macro Etch Test is a visual test method used to ensure proper segregation control in the seam weld during the continuous casting process of steel manufacturing. It involves pickling a disc or cross section of a steel specimen in strong acid until deep etching displays the grains in the parent steel and the weld material. The visual examination of the specimen may show defects such as porosity, inclusions, and poor fusion.

4.6 Vickers Hardness Test.

- (a) The Vickers Hardness Test for seam quality control is the standard method for measuring the hardness of metals, particularly those with extremely hard surfaces. The surface of a material is subjected to a standard pressure for a standard length of time by means of a pyramid-shaped diamond. The diagonal of the resulting indentation is measured under a microscope and the Vickers Hardness value is read from a conversion table. The Vickers Hardness Test permitted the establishment of a continuous scale of comparable numbers that accurately reflected the wide range of hardness found in steels.
- (b) The seam welding process can increase the hardness and reduce the ductility of steel in the heat-affected zone (HAZ), making it more susceptible to brittle fracture.
- (c) Hydrogen embrittlement in the weld seam is a factor that may produce cracking. Harder, stronger steel is more susceptible to hydrogen embrittlement.
- (d) The weld metal and HAZ of the seam can have hardness values much higher than other areas of the steel.
- (e) The aim of weld and HAZ hardness testing is to identify the following.
 - (1) The hardness of the parent metal in order to make an approximate determination of the material's tensile strength.
 - (2) The hardness of the weld to ensure the weld metal meets or exceeds the strength requirements of the parent metal.
 - (3) The hardness of the HAZ to ensure the welding heat input and preheat and interpass temperatures have been controlled sufficiently to produce a HAZ with the appropriate strength and toughness.
 - (4) Areas for fracture toughness testing, where such testing is required.

5 COATING

- (a) Operators are required to use non-shielding coatings for pipelines that may operate at an alternative MAOP (§192.112(f)(1)).
- (b) A *non-shielding coating* is a coating system that allows cathodic protection (CP) current to reach the pipe through areas of disbonded coating, significantly reducing or eliminating potential corrosion damage from water penetration. The following coatings may be used for non-shielding applications.
 - (1) Fusion bonded epoxy (FBE).
 - (2) Two-part epoxy girth weld field joint coating or repair coating.
 - (3) Three-layer coatings.
- (c) Examples of "shielding" coatings:
 - (1) Polyethylene tapes.
 - (2) Some shrink sleeves.
 - (3) Coal tar mastics.

6 FITTINGS AND FLANGES

- (a) Certification records and documentation relative to the manufacturing of fittings and flanges might include the following.
 - (1) Chemical composition of the steel.
 - (2) Physical dimensions of the fitting.
 - (3) Welding procedures.
 - (4) Manufacturing standard (e.g., API, ASME) and process.
 - (5) Carbon equivalent limit.
 - (6) Pressure rating.
 - (7) Toughness rating.
 - (8) Tensile and minimum yield strengths.
- (b) Pre-heating may be required for the installation of fittings, depending on their carbon equivalent.

7 COMPRESSOR STATIONS

See guide material under §192.620 for guidance on pipe segments downstream of compressor stations that operate at an alternative MAOP and have operating temperatures greater than 120 °F.

8 RECORDS

- (a) Records demonstrating compliance for the alternative MAOP must be maintained for the useful life of the pipeline (§192.112). These records might include the following.
- (1) Mill test reports.
 - (2) Quality control testing and inspection documentation.
 - (3) Purchase orders.
 - (4) Material specifications.
 - (5) Steel chemical composition data.
 - (6) Manufacturing 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.

<p>§192.113 Longitudinal joint factor (<i>E</i>) for steel pipe. <i>[Effective Date: 03/06/15]</i></p>
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The longitudinal joint factor to be used in the design formula in §192.105 is determined in accordance with the following table:

Specification	Pipe Class	Longitudinal Joint Factor (<i>E</i>)
ASTM A 53/A53M	Seamless	1.00
	Electric resistance welded	1.00
	Furnace butt welded	0.60
ASTM A 106 ASTM A 333/A 333M	Seamless	1.00
	Seamless	1.00
ASTM A 381 ASTM A 671	Electric resistance welded	1.00
	Double submerged arc welded	1.00
ASTM A 672 ASTM A 691	Electric-fusion-welded	1.00
	Electric-fusion-welded	1.00
API Spec 5L	Seamless	1.00
	Electric resistance welded	1.00
	Electric flash welded	1.00
	Submerged arc welded	1.00
	Furnace butt welded	0.60
Other	Pipe over 4 inches (102 millimeters)	0.80
Other	Pipe 4 inches (102 millimeters) or less	0.60

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

[Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-51, 51 FR 15333, Apr. 23, 1986; 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. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

Manufacture of furnace lap-welded pipe was discontinued and process deleted from API Spec 5L in 1962.

§192.115
Temperature derating factor (T) for steel pipe.
[Effective Date: 07/13/98]

The temperature derating factor to be used in the design formula in §192.105 is determined as follows:

Gas temperature in degrees Fahrenheit (Celsius)	Temperature derating factor (T)
250 °F (121 °C) or less	1.000
300 °F (149 °C)	0.967
350 °F (177 °C)	0.933
400 °F (204 °C)	0.900
450 °F (232 °C)	0.867

For intermediate gas temperatures, the derating factor is determined by interpolation.

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

GUIDE MATERIAL

No guide material necessary.

§192.117
(Removed and reserved.)
[Effective Date: 03/08/89]

§192.119

(Removed and reserved.)

[Effective Date: 03/08/89]

§192.121

Design of plastic pipe.

[Effective Date: 03/12/21]

- (a) **Design pressure.** The design pressure for plastic pipe is determined in accordance with either of the following formulas:

$$P = 2S \frac{t}{(D-t)} (DF)$$

$$P = \frac{2S}{(SDR-1)} (DF)$$

- P*** = Design pressure, gauge, psig (kPa).
S = For thermoplastic pipe, the Hydrostatic Design Basis (HDB) is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2012, (incorporated by reference, see §192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kPa).
t = Specified wall thickness, inches (mm).
D = Specified outside diameter, inches (mm).
SDR = Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standards Institute (ANSI) preferred number series 10.
DF = Design Factor, a maximum of 0.32 unless otherwise specified for a particular material in this section

- (b) **General requirements for plastic pipe and components.**

(1) Except as provided in paragraphs (c) through (f) of this section, the design pressure for plastic pipe may not exceed a gauge pressure of 100 psig (689 kPa) for plastic pipe used in:

- (i) Distribution systems; or
- (ii) Transmission lines in Classes 3 and 4 locations.

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

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

(ii) Above the temperature at which the HDB used in the design formula under this section is determined.

(3) Unless specified for a particular material in this section, the wall thickness for thermoplastic pipe may not be less than 0.062 inches (1.57 millimeters).

(4) All plastic pipe must have a listed HDB in accordance with PPI TR-4/2012 (incorporated

by reference, see §192.7).

(c) *Polyethylene (PE) pipe requirements*

(1) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided:

(i) The material designation code is PE2406 or PE3408.

(ii) The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and

(iii) The wall thickness is not less than 0.062 inches (1.57 millimeters).

(2) For PE pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

(i) The design pressure does not exceed 125 psig;

(ii) The material designation code is PE2708 or PE4710;

(iii) The pipe has a nominal size (IPS or CTS) of 24 inches or less; and

(iv) The wall thickness for a given outside diameter is not less than that listed in table 1 to this paragraph (c)(2)(iv).

Table 1 to Paragraph (c)(2)(iv)
PE Pipe: Minimum Wall Thickness and SDR Values

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
1/2" CTS.....	0.090	7
1/2" IPS.....	0.090	9.3
3/4" CTS.....	0.090	9.7
3/4" IPS.....	0.095	11
1" CTS.....	0.099	11
1" IPS.....	0.119	11
1 1/4" IPS.....	0.151	11
1 1/2" IPS.....	0.173	11
2"	0.216	11
3"	0.259	13.5
4"	0.265	17
6"	0.315	21
8"	0.411	21
10"	0.512	21
12"	0.607	21
16"	0.762	21
18"	0.857	21
20"	0.952	21
22"	1.048	21
24"	1.143	21

(d) *Polyamide (PA-11) pipe requirements.*

(1) For PA-11 pipe produced after January 23, 2009, but before January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

(i) The design pressure does not exceed 200 psig;

(ii) The material designation code is PA32312 or PA32316;

(iii) The pipe has a nominal size (IPS or CTS) of 4 inches or less; and

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

(2) For PA–11 pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

- (i) The design pressure does not exceed 250 psig;
- (ii) The material designation code is PA32316;
- (iii) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and
- (iv) The minimum wall thickness for a given outside diameter is not less than that listed in table 2 to paragraph (d)(2)(iv):

Table 2 to Paragraph (d)(2)(iv)
PA-11: Pipe Minimum Wall Thickness and SDR Values

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½" CTS.....	0.090	7.0
½" IPS.....	0.090	9.3
¾" CTS.....	0.090	9.7
¾" IPS.....	0.095	11
1" CTS.....	0.099	11
1" IPS.....	0.119	11
1 ¼" IPS.....	0.151	11
1 ½" IPS.....	0.173	11
2" IPS	0.216	11
3" IPS	0.259	13.5
4" IPS	0.333	13.5
6" IPS.....	0.491	13.5

(e) *Polyamide (PA–12) pipe requirements.* For PA–12 pipe produced after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:

- (1) The design pressure does not exceed 250 psig;
- (2) The material designation code is PA42316;
- (3) The pipe has a nominal size (IPS or CTS) of 6 inches or less; and
- (4) The minimum wall thickness for a given outside diameter is not less than that listed in table 3 to paragraph (e)(4).

Table 3 to Paragraph (e)(4)
PA-12 Pipe Minimum Wall Thickness and SDR Values

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
½" CTS.....	0.090	7
½" IPS.....	0.090	9.3
¾" CTS.....	0.090	9.7
¾" IPS.....	0.095	11
1" CTS.....	0.099	11
1" IPS.....	0.119	11
1 ¼" IPS.....	0.151	11
1 ½" IPS.....	0.173	11
2" IPS.....	0.216	11
3" IPS.....	0.259	13.5
4" IPS.....	0.333	13.5
6" IPS.....	0.491	13.5

(f) Reinforced thermosetting plastic pipe requirements.

(1) Reinforced thermosetting plastic pipe may not be used at operating temperatures above 150 °F (66 °C).

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

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

[Amdt. 192-31, 43 FR 13880, Apr. 3, 1978 with Amdt. 192-31 Correction, 43 FR 43308, Sept. 25, 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. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE26, 73 FR 79002, Dec. 24, 2008; Amdt. 192-111, 74 FR 62503, Nov. 30, 2009; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

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

1 NATURAL GAS

- (a) Hydrostatic Design Basis (HDB) values are awarded by the Hydrostatic Stress Board (HSB) of the Plastics Pipe Institute (PPI) and are listed in PPI TR-4, which can be accessed at:
www.plasticpipe.org
- (b) ASTM D2513 (see §192.7 for IBR as listed specification) requires elevated temperature HDB listings for plastic piping materials used at temperatures above 73 °F. PPI publishes elevated temperature HDB values for PE and PA materials in TR-4.
- (c) Long-term hydrostatic strength (LTHS) for reinforced thermosetting plastic covered by ASTM D2517 (see §192.7 for IBR as listed specification) is 11,000 psi.
- (d) HDB values apply only to materials meeting all the requirements of ASTM D2513 and are based on engineering test data analyzed in accordance with ASTM D2837, "Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products."
- (e) HDB values at 73 °F for thermoplastic materials covered by ASTM D2513 are listed in Table 192.121i. The values used in the design formula for thermoplastic materials are actually HDB values that are a categorized value of the long-term hydrostatic strength.

Pipe Material	HDB @ 73 °F, psi
PA 32312 (PA 11)	2500
PE 2406/PE 2708 ¹	1250
PE 3408/PE 4710 ¹	1600
PVC Type I, Grade 1, Class 12454B (PVC 1120) ²	4000
PVC Type II, Grade 1, Class 1433D (PVC 2116) ²	3200
¹ Pipe material designation codes PE 2406 and PE 3408 are listed in the 1999 edition of ASTM D2513. Pipe material designation codes PE 2708 and PE 4710 are listed in the current edition of ASTM D2513. Until PHMSA-OPS references the more recent edition of ASTM D2513, PE pipe is dual marked as PE 2406/PE 2708 or PE 3408/PE 4710. ² Editions of ASTM D2513 issued after 2001 no longer permit use of PVC piping for new gas piping installations, but do specify that it may be used for repair and maintenance of existing PVC gas piping. The Regulations may continue to reference an edition of ASTM D2513 earlier than 2001. The operator is advised to check §192.7.	

TABLE 192.121i

2 PETROLEUM GASES

PE and PA materials listed in ASTM D2513 may be used for liquid petroleum gas (LPG) piping applications. NFPA 58 (see §192.7 for IBR for §192.11) prescribes the following:

- (a) PA may be used in liquid or vapor LPG systems up to the design pressure of the piping material. PPI recommends a chemical derating factor of 1.0 (no derating) for PA 11 piping.
- (b) PE, when recommended by the manufacturer, may be used in vapor-only LPG systems up to 30 psig pressure. PPI recommends a 0.5 chemical derating factor for the use of PE piping.
- (c) PVC is not permitted.

Some information on the strengths of polyethylenes with propane is given in PPI TR-22, "Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases." See guide material under §192.123.

3 MINIMUM REQUIRED WALL THICKNESS

The minimum wall thickness (t_m) for a given design pressure is determined from the formula below. Also, see §192.123(c) and (d) plus 3 of the guide material under §192.123.

$$t_m = \frac{PD}{(P + 0.64 S)}$$

Where:

- P = Design pressure, gauge, psi (kPa)
- D = Nominal (Specified) outside diameter, in. (mm) as shown in Table 192.121ii for commonly used tubing
- S = HDB, for thermoplastic pipe, psi (kPa) determined at 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C); for reinforced thermosetting pipe, 11,000 psi (75,800 kPa)

COMMONLY USED TUBING ¹	
Nominal Tubing Size (CTS) ²	Nominal (Specified) Outside Diameter (D) ² (inches)
¼	0.375
⅜	0.500
½	0.625
¾	0.875
1	1.125
1¼	1.375
1¾	1.875

¹ Values obtained from ASTM D2513, Table 2.
² Applies to copper and plastic tubing.

TABLE 192.121ii

4 INTERPOLATION OF HYDROSTATIC DESIGN BASIS (HDB) VALUES

- (a) For thermoplastic pipe that is to be installed at a service temperature greater than 73 °F and less than that at which the next HDB has been established, the HDB at the anticipated service temperature can be determined by interpolation. The pipe manufacturer should be consulted for assistance in determining an interpolated HDB.
- (b) The interpolation formula as prescribed in §192.121 is published in PPI TR-3 (see §192.7 for IBR) as follows.

$$S_T = S_L - \frac{(S_L - S_H)\left(\frac{1}{T_L} - \frac{1}{T_T}\right)}{\left(\frac{1}{T_L} - \frac{1}{T_H}\right)}$$

Where:

- S_T = Interpolated LTHS for the anticipated service temperature, psi
- S_L = LTHS established at a temperature below the anticipated service temperature, psi
- S_H = LTHS established at a temperature above the anticipated service temperature, psi
- T_L = Temperature at which the lower LTHS (S_L) was established, K
- T_T = Anticipated service temperature, K
- T_H = Temperature at which the higher LTHS (S_H) was established, K

- (c) Section 192.121 requires that the interpolation be made between the LTHS values at the lower and higher temperatures. The resulting interpolated LTHS is categorized into an HDB. This interpolated HDB is then used to determine the design pressure under §192.121.
- (d) Example:
An operator is installing SDR 11 PE pipe where the anticipated service temperature is 78 °F. HDB values are established and published in PPI TR-4 at 73 °F (296 K) and 140 °F (333 K). Thus, the operator has the option of establishing an interpolated HDB at the anticipated service temperature, 78 °F (299 K), or using the 140 °F HDB of 800 psi.
 - (1) In order to calculate the HDB for the anticipated service temperature, the operator must obtain the actual LTHS values established for the material at the nearest temperature above and below

the temperature for which the interpolated value is to be determined. These values are typically available from the pipe supplier. If these LTHS values are not available, the lowest LTHS for the HDB category in Table 192.121ii may be used as a conservative estimate.

- (2) Once the LTHS values are obtained, the interpolation calculation input is as follows.

$$\begin{aligned} S_{L(73\text{ }^{\circ}\text{F})} &= 1567 \text{ psi} \\ S_{H(140\text{ }^{\circ}\text{F})} &= 845 \text{ psi} \\ T_L &= 73\text{ }^{\circ}\text{F} (295.93 \text{ K}) \\ T_T &= 78\text{ }^{\circ}\text{F} (298.71 \text{ K}) \\ T_H &= 140\text{ }^{\circ}\text{F} (333.15 \text{ K}) \end{aligned}$$

Hence, the interpolation calculation determines that $S_T = 1506.86$ psi or 1507 psi.

- (3) To determine the HDB at 78 °F, the interpolated LTHS value is categorized using Table 1 from ASTM Standard D2837-04, a selection of which is shown in Table 192.121iii.

Range of Calculated LTHS Values		Hydrostatic Design Basis (HDB)	
Psi	(MPa)	Psi	(MPa)
600 to <760	(4.14 to <5.24)	630	(4.34)
760 to <960	(5.24 to <6.62)	800	(5.52)
960 to <1200	(6.62 to <8.27)	1000	(6.89)
1200 to <1530	(8.27 to <10.55)	1250	(8.62)
1530 to <1920	(10.55 to <13.24)	1600	(11.03)

TABLE 192.121iii

- (4) Based upon an interpolated LTHS value of 1510 psi, the HDB to be used in the design formula for this example is 1250 psi.

For this SDR 11 PE pipe with an anticipated service temperature of 78 °F, the design pressure is calculated in accordance with §192.121 using the interpolated HDB of 1250 psi as follows.

$$P = \frac{2S}{(SDR-1)} (.32) = \frac{2(1250\text{psi})}{(11-1)} (.32) = 80\text{psig}$$

5 REFERENCES

- PPI TR-4, "PPI Listing of Hydrostatic Design Basis (HDB), Hydrostatic Design Stress (HDS), Strength Design Basis (SDB), Pressure Design Basis (PDB) and Minimum Required Strength (MRS) Ratings for Thermoplastic Piping Materials or Pipe."
- PPI TR-22, "Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases."

§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.

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

Where:

$P_{de-rated}$ = De-rated design pressure, gauge, psig (kPa).

$P_{§192.121}$ = 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. Pizzi 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 PLASTIC PIPE MANUFACTURED BEFORE MAY 18, 1978

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

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

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

6 MECHANICAL FITTINGS

ASTM Subcommittee F17.60 publishes the following specifications to qualify mechanical fittings that connect plastic pipe for design temperatures from -20 °F to 140 °F.

- (a) ASTM F1924, "Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing."
- (b) ASTM F1948, "Standard Specification for Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing."
- (c) ASTM F1973, "Standard Specification for Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems."

7 INSTALLATION OF PA-11 PIPING FOR HIGHER PRESSURE APPLICATIONS

See 9 of the guide material under §192.321.

§192.125

Design of copper pipe.

[Effective Date: 07/13/98]

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

(b) Copper pipe used in service lines must have wall thickness not less than that indicated in the following table:

Standard size inch (millimeter)	Nominal O.D. inch (millimeter)	Wall thickness inch (millimeter)	
		Nominal	Tolerance
1/2 (13)	.625 (16)	.040 (1.06)	.0035 (.0889)
5/8 (16)	.750 (19)	.042 (1.07)	.0035 (.0889)
3/4 (19)	.875 (22)	.045 (1.14)	.0040 (.1020)
1 (25)	1.125 (29)	.050 (1.27)	.0040 (.1020)
1 1/4 (32)	1.375 (35)	.055 (1.40)	.0045 (.1143)
1 1/2 (38)	1.625 (41)	.060 (1.52)	.0045 (.1143)

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

(d) Copper pipe that does not have an internal corrosion resistant lining may not be used to carry gas that has an average hydrogen sulfide content of more than 0.3 grains/100 ft³ (6.9/m³) under standard conditions. Standard conditions refers to 60 °F and 14.7 psia (15.6 °C and one atmosphere) of gas.

[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

See §192.377 for additional requirement regarding copper service lines.

§192.127

Records: Pipe design.

[Effective Date: 07/01/20]

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

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

GUIDE MATERIAL

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

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SUBPART D DESIGN OF PIPELINE COMPONENTS

<p>§192.141 Scope.</p> <p style="text-align: right;"><i>[Effective Date: 11/12/70]</i></p>
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This subpart prescribes minimum requirements for the design and installation of pipeline components and facilities. In addition, it prescribes requirements relating to protection against accidental overpressuring.

GUIDE MATERIAL

Industry references for design and construction of auxiliary piping for compressor stations or other similar installations (other than gas piping) are listed in Table 192.141i. Federal, state, and local requirements may also apply.

Piping System	Fluid	Design Code
Power piping (boiler external piping)	Air, steam, water, oil, gas, steam condensate	ASME B31.1
Power piping (non-boiler external piping)	Air, steam, water, oil, gas, steam condensate	ASME B31.3
Utility, auxiliary, process, air injection	Air, steam, water, oil, steam condensate, glycol, natural gas liquids	ASME B31.3
Process	Hydrocarbons, chemicals	ASME B31.3
Refrigeration	Refrigerant (e.g., propane)	ASME B31.3 or B31.5
Fire protection	Water	NFPA 14 and 24
Drinking and domestic supply	Water	AWWA Standards; Uniform Plumbing Code
Plumbing and drains	Sanitary and waste water	Uniform Plumbing Code

TABLE 192.141i

<p>§192.143 General requirements.</p> <p style="text-align: right;"><i>[Effective Date: 01/22/19]</i></p>

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

pressure rating established by the manufacturer by pressure testing that component or a prototype of the component.

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

(c) Except for excess flow valves, each plastic pipeline component installed after January 22, 2019 must be able to withstand operating pressures and other anticipated loads in accordance with a listed specification.

[Amdt. 192-48, 49 FR 19823, May 10, 1984; RIN 2137-AE09, 72 FR 20055, April 23, 2007; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

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

1 GENERAL

The designer should select components that will withstand the field test pressure to which they will be subjected without failure or leakage and without impairment to their serviceability. Consideration should also be given to pulsation-induced vibrations that could produce excessive cyclic stresses.

See Guide Material Appendices G-192-9 and G-192-10.

2 CORROSION CONTROL

See guide material under §§192.453, 192.455, 192.461, 192.467, 192.469, 192.471, 192.473, 192.475, 192.476, 192.479, and 192.491.

§192.144

Qualifying Metallic Components.

[Effective Date: 07/14/04]

Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in §192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if —

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

(b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §192.7 or appendix B of this part:

- (1) Pressure testing;
- (2) Materials; and
- (3) Pressure and temperature ratings.

[Issued by Amdt. 192-45, 48 FR 30637, July 5, 1983; Amdt. 192-94, 69 FR 32886, June 14, 2004]

GUIDE MATERIAL

(a) See Guide Material Appendix G-192-1A for documents previously incorporated by reference in the

Regulations. Current documents incorporated by reference that were listed in Appendix A prior to Amendment 192-94, published June 14, 2004, are now found in §192.7.

- (b) If the edition of the document under which the component was manufactured was neither previously listed nor currently listed in §192.7, and was not previously listed in Appendix A, then requirements under §192.144(b) should be reviewed to determine if the metallic component is qualified for use under Part 192. Gas quality and composition should be considered for components used in gathering systems.

Note: See guide material under §192.51.

§192.145

Valves.

[Effective Date: 01/22/19]

- (a) Except for cast iron and plastic valves, each valve must meet the minimum requirements of ANSI/API Spec 6D (incorporated by reference, see §192.7), or to a national or international standard that provides an equivalent performance level. A valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.
- (b) Each cast iron and plastic valve must comply with the following:
- (1) The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.
 - (2) The valve must be tested as part of the manufacturing, as follows:
 - (i) With the valve in the fully open position, the shell must be tested with no leakage to a pressure at least 1.5 times the maximum service rating.
 - (ii) After the shell test, the seat must be tested to a pressure not less than 1.5 times the maximum service pressure rating. Except for swing check valves, test pressure during the seat test must be applied successively on each side of the closed valve with the opposite side open. No visible leakage is permitted.
 - (iii) After the last pressure test is completed, the valve must be operated through its full travel to demonstrate freedom from interference.
- (c) Each valve must be able to meet the anticipated operating conditions.
- (d) No valve having shell (body, bonnet, cover, and/or end flange) components made of ductile iron may be used at pressures exceeding 80 percent of the pressure ratings for comparable steel valves at their listed temperature. However, a valve having shell components made of ductile iron may be used at pressures up to 80 percent of the pressure ratings for comparable steel valves at their listed temperature, if —
- (1) The temperature-adjusted service pressure does not exceed 1,000 p.s.i (7 MPa) gage;
- and
- (2) Welding is not used on any ductile iron component in the fabrication of the valve shells or their assembly.
- (e) No valve having shell (body, bonnet, cover, and/or end flange) components made of cast iron, malleable iron, or ductile iron may be used in the gas pipe components of compressor stations.
- (f) Except for excess flow valves, plastic valves installed after January 22, 2019, must meet the minimum requirements of a listed specification. A valve may not be used under operating conditions that exceed the applicable pressure and temperature ratings contained in the listed specification.

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-22, 41 FR 13589, Mar. 31, 1976; Amdt. 192-37, 46

FR 10157, Feb. 2, 1981; Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; 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 FLANGED CAST IRON VALVES IN STEEL PIPELINES

Consideration should be given to the effect of secondary stresses (e.g., those resulting from earth movement, expansion and contraction, or other external forces) which could affect the structural integrity of flanged cast iron valves in steel pipelines. The operator should consider the following.

- (a) Adequate support, for the both the cast iron valve and the adjacent steel piping.
- (b) If compression couplings are used, the couplings should be designed to resist axial stresses from the adjacent steel piping.
- (c) Other means.

For joining considerations, see 1, 2, 3, and 6 of the guide material under §192.273.

2 EQUIVALENT STANDARDS FOR STEEL VALVES

2.1 Equivalent standards.

Valve standards API Spec 6A, API Std 600, ASME B16.33, ASME B16.34, and ASME B16.38 provide an equivalent performance level to API Spec 6D (see §192.7 for IBR) for gas application purposes.

2.2 Valves not listed in API Spec 6D.

Although all valve sizes (e.g., those smaller than 2 inches) are not listed in API Spec 6D, manufacturers may design, build, and test non-listed sizes in accordance with all applicable requirements of API Spec 6D and, thereby, meet the equivalency criteria. However, application of the API monogram to valve sizes not listed in the API Specification is not permitted.

3 PRESSURE-TEMPERATURE RATING

Any valve which cannot comply to the API Spec 6D standard pressure-temperature rating because of material(s) which require a reduced maximum temperature limit should be provided with markings on the nameplate showing the maximum pressure rating at that temperature and with the pressure rating at 100 °F.

4 GAS COMPOSITION

If the gas to be transported could contain constituents such as carbon dioxide, hydrogen sulfide, free water, brine, oxygen, or liquid hydrocarbons, the selection of valves should include evaluation for material compatibility. See additional guide material under §192.475.

5 PLASTIC VALVES

ASTM D2513 (see listing in §192.7, not IBR for §192.145) requires that plastic valves meet the requirements of ASME B16.40, "Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems." The manufacturing test requirements outlined in §192.145(b) for plastic valves are part of the testing requirements outlined in ASME B16.40.

6 COMPRESSOR STATION PIPING COMPONENTS

Steel valves with balls or plugs constructed from cast iron, malleable iron, or ductile iron may be installed in compressor station piping.

§192.147

Flanges and flange accessories.

[Effective Date: 03/06/15]

(a) Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5 and MSS SP-44 (incorporated by reference, see §192.7), or the equivalent.

(b) Each flange assembly must be able to withstand the maximum pressure at which the pipeline is to be operated and to maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.

(c) Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 (incorporated by reference, see §192.7) and be cast integrally with the pipe, valve, or fitting.

[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

1 FLANGES

1.1 Flange types.

(a) The dimensions and drilling for all line or end flanges should conform to one of the following standards.

ASME B16.1, ASME B16.5, ASME B16.36, ASME B16.47, ASME B16.48, AWWA C207, or MSS SP-44 as listed in either §192.7 or Guide Material Appendix G-192-1.

Flanges cast or forged integral with pipe, fittings or valves in sizes and for the maximum service rating covered by the standards listed above may be used subject to the facing, bolting and gasketing requirements of this paragraph and 1.2, 2.1 and 2.2 below.

(b) Threaded companion flanges that comply with either ASME B16.1 or ASME B16.5 (see §192.7 for IBR for both), in sizes and for maximum service ratings covered by these standards, may be used.

(c) Lapped flanges in sizes and pressure standards established by ASME B16.5 may be used.

(d) Slip-on welding flanges in sizes and pressure standards established in ASME B16.5 may be used. Slip-on flanges of rectangular section may be substituted for hubbed slip-on flanges provided the thickness is increased as required to produce equivalent strength as determined by calculations made in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII (see listing in §192.7, not IBR for §192.147).

(e) Welding neck flanges in sizes and pressure standards established in ASME B16.5 and MSS SP-44 (see §192.7 for IBR for both) and ASME B16.47 may be used. The bore of the flanges should correspond to the inside diameter of the pipe used. For acceptable welding end treatment, see Guide Material Appendix G-192-5, Figure 192.235B.

(f) Flanges made of ductile iron should conform to material and dimensional standards listed in §192.145(a) and should be subject to all service restrictions as outlined for valves in that paragraph. The bolting requirements for ductile-iron flanges should be the same as for carbon and low-alloy steel flanges as listed in 2.1 below.

1.2 Flange facings.

(a) Cast iron, ductile iron, and steel flanges should have contact faces finished in accordance with MSS SP-6, Finishes for Contact Faces of Pipe Flanges of Connecting-End Flanges of Valves and Fittings.

(b) Class 25 and Class 125 cast iron integral or threaded companion flanges may be used with a full-face gasket or with a flat ring gasket extending to the inner edge of the bolt holes. When using a full-face gasket, the bolting may be of alloy steel (ASTM A193). When using a ring gasket, the bolting

should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B.

- (c) When bolting together two Class 250 integral or threaded companion cast iron flanges, having 1/16 inch raised faces, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B.
- (d) Class 150 steel flanges may be bolted to Class 125 cast iron flanges. When such construction is used, the 1/16 inch raised face on the steel flange should be removed. When bolting such flanges together, using a flat ring gasket extending to the inner edge of the bolt holes, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B. When bolting such flanges together using a full-face gasket, the bolting may be alloy steel (ASTM A193).
- (e) Class 300 steel flanges may be bolted to Class 250 cast iron flanges. Where such construction is used, the bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B. It is recommended that the raised face on the steel flange be removed. When this is done, bolting should be of carbon steel, without heat treatment other than stress relief, equivalent to ASTM A307 Grade B.
- (f) Forged steel welding neck flanges with an outside diameter and drilling the same as ASME B16.1 (see §192.7 for IBR), but with modified flange thicknesses, hub dimensions, and special facing details, may be used to bolt against flat-faced cast iron flanges, and may operate at the pressure-temperature ratings given in ASME B16.1 Class 125 Cast Iron Pipe Flanges provided:
 - (1) The minimum flange thickness, T , of the steel flange is not less than that specified for 6-inch diameter and larger.
 - (2) Flanges are used with nonmetallic full-face gaskets extending to the periphery of the flange.
 - (3) The design joint has been proven by test to be suitable for the ratings.

2 FLANGE ACCESSORIES

2.1 Bolting.

- (a) For all flange joints other than described under 1.2(c), (d), (e) and (f), the bolting should be made of alloy steel conforming to ASTM A193, A320 or A354, or of heat-treated carbon steel conforming to ASTM A449. However, bolting for American National Standard Class 250 and 300 flanges to be used at temperatures between minus 20 °F and plus 450 °F may be made to ASTM A307, Grade B.
- (b) Alloy steel bolting material conforming to ASTM A193 or ASTM A354 should be used for insulating flanges if such bolting is made 1/8 inch undersized.
- (c) The materials used for nuts should conform to ASTM A194 and A307. A307 nuts may be used only with A307 bolting.
- (d) All carbon and alloy steel bolts, stud bolts, and their nuts should be threaded in accordance with the following thread series and dimension class as required by ASME B1.1.
 - (1) *Carbon Steel* - All carbon steel bolts and stud bolts should have coarse threads, Class 2A dimensions and their nuts, Class 2B dimensions.
 - (2) *Alloy Steel* - All alloy steel bolts and stud bolts of 1 inch and smaller nominal diameters should be of the coarse thread series; nominal diameters 1 1/8 inch and larger should be of the 8 thread series. Bolts and stud bolts should have a Class 2A dimension, and their nuts should have a Class 2B dimension.
- (e) Bolts should have American National Standard regular square heads or heavy hexagonal heads and should have American National Standard heavy hexagonal nuts conforming to the dimensions of ASME B18.2.1 and B18.2.2.
- (f) Nuts cut from bar stock in such a manner that the axis will be parallel to the direction of rolling of the bar may be used in all sizes for joints in which one or both flanges are cast iron, and for joints with steel flanges where the pressure does not exceed 250 psig. Such nuts should not be used for joints in which both flanges are steel and the pressure exceeds 250 psig except that, for nut sizes 1/2 inch and smaller, these limitations do not apply.
- (g) For all flange joints, the bolts or stud bolts used should extend completely through the nuts.

2.2 Gaskets.

- (a) Material for gaskets should be capable of withstanding the maximum pressure and maintaining its physical and chemical properties at any temperature to which it might reasonably be subjected in service.
- (b) Gaskets used under pressure and at temperatures above 250 °F should be of noncombustible material. Metallic gaskets should not be used with Class 150 standard or lower-rated flanges.
- (c) Full-face gaskets should be used with all bronze flanges, and may be used with Class 25 or Class 125 cast iron flanges. Flat ring gaskets with outside diameter extending to the inside of the bolt holes may be used with cast iron flanges, with raised face steel flanges, or with lapped steel flanges.
- (d) In order to secure higher unit compression on the gasket, metallic gaskets of a width less than the full male face of the flange may be used with raised face, lapped, or large male and female facings. The width of the gasket for small male and female or for tongue and groove joints should be equal to the width of the male face or tongue.
- (e) Rings for ring joints should be of dimensions established in ASME B16.20. The material for these rings should be suitable for the service conditions encountered and should be softer than the flanges.

2.3 *Insulating kits.*

- (a) Insulating kits are available to provide electrical isolation at flanged connections. Insulating kits typically contain a gasket, washers, and sleeves for the bolts.
- (b) Insulating kits should be specified to be compatible with both the gas stream and the external environment (e.g., temperature, pressure, gas quality or composition, moisture).
- (c) Assembly.
 - (1) Carefully inspect the insulating kit components for rough edges, cracks, delaminations, or other defects that could contribute to crushing, cracking, or loss of seal under load.
 - (2) Ensure proper flange alignment and follow the manufacturer's assembly instructions, including torque values that may vary from non-insulating flange assemblies.
 - (3) Prior to coating or painting flanged connections, verify that desired insulating properties have been attained.
 - (4) Coating or painting materials should be nonconductive.
- (d) Post assembly.
 - (1) Where possible, include the assembled insulating flange in pressure testing or perform an instrumented leak test prior to coating or painting.
 - (2) If the assembly is to be buried, consider providing a test station with test leads and bonding wires for future test capability. See §§192.469 and 192.471.
 - (3) Consider providing for ground fault, lightning protection, or temporary bonding. See §192.467.

3 FLANGE INSTALLATION AND MAINTENANCE

Proper installation and maintenance of flanged joints are critical for maintaining safe operation of pipeline facilities.

3.1 *Flange preparation.*

- (a) The sealing surfaces of the flanges should be clean and smooth.
- (b) To seal properly, the sealing faces should be installed parallel to each other.

3.2 *Bolting methods.*

Methods for tightening flange bolts may include the use of torque wrenches or the use of hydraulic stud tensioners.

- (a) Bolt torque values.
 - (1) The proper bolt torque values are based on gasket material, flange size, flange type, flange rating, bolt size, bolt material, and thread lubricant. When available, the gasket manufacturer's recommended torque values should be followed.
 - (2) The minimum torque value represents the amount of force required to provide proper compression of the gasket to prevent leakage.
 - (3) The maximum torque value represents a torque limit to prevent gasket crushing, bolt yielding,

- flange deformation, or flange cracking.
- (4) Thread lubrication significantly influences the amount of torque actually applied to the flange assembly. All flange bolts should be lubricated, and lubrication can be accomplished by using pre-coated bolts or by the field application of thread lubricants.
- (b) Bolt torque procedure.
Bolt torque should be applied evenly across the flange and is normally applied in several steps. Bolt torque should be applied using manual or hydraulic torque wrenches. The following method provides an example of applying torque. The number of steps may vary based on recommendations of the gasket manufacturer and operator requirements. Except for the final step, use a star or crisscross pattern to tighten the bolts.
- (1) Install and hand tighten all bolts and nuts.
 - (2) Tighten all bolts to 30% of the final torque value.
 - (3) Tighten all bolts to 60% of the final torque value.
 - (4) Tighten all bolts to 100% of the final torque value.
 - (5) Follow a circular pattern and ensure that all bolts are tightened to 100% of the final torque value.
- (c) Hydraulic tensioning.
Hydraulic tensioning involves stretching the bolt to achieve a desired elongation as the nut is tightened onto the flange bolt. Advantages of hydraulic tensioning include the elimination of friction factor errors and more uniform gasket loading. The disadvantages of hydraulic tensioning include the need for longer studs, specialized equipment, and additional workspace.

§192.149

Standard fittings.

[Effective Date: 01/22/18]

- (a) The minimum metal thickness of threaded fittings may not be less than specified for the pressures and temperatures in the applicable standards referenced in this part, or their equivalent.
- (b) Each steel butt-welding fitting must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.
- (c) Plastic fittings installed after January 22, 2019, must meet a listed specification.

GUIDE MATERIAL

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

- (a) Steel butt-welding fittings should comply with either ASME B16.9 or MSS SP-75 and should have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.
- (b) Steel induction bends should comply with ASME B16.49 and should have pressure and temperature ratings based on stresses for pipe of the same or equivalent material.
- (c) Threaded fittings should comply with ASME B16.3, ASME B16.4, ASME B16.11, ASME B16.14, ASME B16.15, ASTM A733, MSS SP-83, or equivalent as appropriate.
- (d) Socket welding fittings should comply with ASME B16.11, MSS SP-79, or MSS SP-83 or equivalent as appropriate.

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

§192.150

Passage of internal inspection devices.

[Effective Date: 07/01/2020]

- (a) Except as provided in paragraphs (b) and (c) of this section, each new transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, section 7 (incorporated by reference, see §192.7).
- (b) This section does not apply to:
- (1) Manifolds;
 - (2) Station piping such as at compressor stations, meter stations, or regulator stations;
 - (3) Piping associated with storage facilities, other than a continuous run of transmission line between a compressor station and storage facilities;
 - (4) Cross-overs;
 - (5) Sizes of pipe for which an instrumented internal inspection device is not commercially available;
 - (6) Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations;
 - (7) Offshore transmission lines, except transmission lines 10³/₄ inches (273 millimeters) or more in outside diameter on which construction begins after December 28, 2005, that run from platform to platform or platform to shore unless —
 - (i) Platform space or configuration is incompatible with launching or retrieving instrumented internal inspection devices; or
 - (ii) If the design includes taps for lateral connections, the operator can demonstrate, based on investigation or experience, that there is no reasonably practical alternative under the design circumstances to the use of a tap that will obstruct the passage of instrumented internal inspection devices;
 - (8) Gathering lines; and
 - (9) Other piping that, under §190.9 of this chapter, the Administrator finds in a particular case would be impracticable to design and construct to accommodate the passage of instrumented internal inspection devices.
- (c) An operator encountering emergencies, construction time constraints or other unforeseen construction problems need not construct a new or replacement segment of a transmission line to meet paragraph (a) of this section, if the operator determines and documents why and impracticability prohibits compliance with paragraph (a) of this section. Within 30 days after discovering the emergency or construction problem the operator must petition, under §190.9 of this chapter, for approval that design and construction to accommodate passage of instrumented internal inspection devices would be impracticable. If the petition is denied, within 1 year after the date of the notice of the denial, the operator must modify that segment to allow passage of instrumented internal inspection devices.

[Issued by Amdt. 192-72, 59 FR 17275, April 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. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-97, 69 FR 36024, June 28, 2004, Amdt. 192-125, Oct. 1, 2019; Amdt. 192-129, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

1 REFERENCES

See Guide Material Appendix G-192-14 for design and construction considerations.

2 GATHERING LINES

Type A gathering lines are exempt from this requirement (§192.9(c)). No exemption exists for Type B gathering lines (§192.9(d)).

§192.151

Tapping.

[Effective Date: 07/13/98]

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

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

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

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

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

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

GUIDE MATERIAL

1 DESIGN

1.1 *Proprietary fittings.*

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

(b) Pressure-temperature ratings. Published catalog or engineering data supplied by a reputable manufacturer or designer is usually sufficient. When the rating cannot be so established, it should be established by test in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code, Section VIII (see listing in §192.7, not IBR for §192.151).

1.2 *Other fittings.*

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

1.3 *Branch connection.*

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

Addendum 1, June 2022

Addendum 3, July 2023

Addendum 4, May 2024

2 PRESSURE LIMITATIONS

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

3 SIZE LIMITATIONS

3.1 *Large-diameter taps.*

Large-diameter taps using mechanical fittings can reduce the remaining circumferential area below that required to withstand anticipated longitudinal forces due to pressure, bending, and thermal effects. The operator should anticipate and design for complete circumferential cracking. The operator should confirm that the longitudinal pullout resistance of the fitting is adequate, or provide appropriate restraint, such as a mechanical harness, strapping, or girth (fillet) end welds. For welds, see guide material under §192.713.

3.2 *Oversize taps.*

When an oversize tap (i.e., greater than 25% of the nominal diameter) into cast iron or ductile-iron pipe is made through a band-type fitting, it is common practice to use a full-encirclement gasket for leak containment in the event of a circumferential crack.

4 SEPARATION

To resist longitudinal cracks between taps, taps into cast iron or ductile-iron pipe should be separated longitudinally by at least the circumference of the pipe being tapped.

5 OTHER

See guide material under §192.627 for personnel qualifications, identification of pipe to be tapped, and suitability for tapping. See §192.627 for tapping pipelines under pressure.

§192.153

Components fabricated by welding.

[Effective Date: 03/12/21]

(a) Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see §192.7).

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with the ASME BPVC (Rules for Construction of Pressure Vessels as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, see § 192.7), except for the following:

(1) Regularly manufactured butt welding fittings.

(2) Pipe that has been produced and tested under a specification listed in appendix B to this part.

(3) Partial assemblies such as split rings or collars.

(4) Prefabricated units that the manufacturer certifies have been tested to at least twice the

maximum pressure to which they will be subjected under the anticipated operating conditions.

(c) Orange-peel bull plugs and orange-peel swages may not be used in pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.

(d) Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2), flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage or more, or is more than 3 inches in (76 millimeters) nominal diameter.

(e) The test requirements for a prefabricated unit or pressure vessel, defined for this paragraph as components with a design pressure established in accordance with paragraph (a) or paragraph (b) of this section are as follows.

(1) A prefabricated unit or pressure vessel installed after July 14, 2004 is not subject to the strength testing requirements at § 192.505(b) provided the component has been tested in accordance with paragraph (a) or paragraph (b) of this section and with a test factor of at least 1.3 times MAOP.

(2) A prefabricated unit or pressure vessel must be tested for a duration specified as follows:

(i) A prefabricated unit or pressure vessel installed after July 14, 2004, but before October 1, 2021 is exempt from §§ 192.505(c) and (d) and 192.507(c) provided it has been tested for a duration consistent with the ASME BPVC requirements referenced in paragraph (a) or (b) of this section.

(ii) A prefabricated unit or pressure vessel installed on or after October 1, 2021 must be tested for the duration specified in either § 192.505(c) or (d), § 192.507(c), or § 192.509(a), whichever is applicable for the pipeline in which the component is being installed.

(3) For any prefabricated unit or pressure vessel permanently or temporarily installed on a pipeline facility, an operator must either:

(i) Test the prefabricated unit or pressure vessel in accordance with this section and Subpart J of this part after it has been placed on its support structure at its final installation location. The test may be performed before or after it has been tied-in to the pipeline. Test records that meet § 192.517(a) must be kept for the operational life of the prefabricated unit or pressure vessel; or

(ii) For a prefabricated unit or pressure vessel that is pressure tested prior to installation or where a manufacturer's pressure test is used in accordance with paragraph (e) of this section, inspect the prefabricated unit or pressure vessel after it has been placed on its support structure at its final installation location and confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection procedure and documented inspection must include visual inspection for vessel damage, including, at a minimum, inlets, outlets, and lifting locations. Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. This inspection must be performed prior to operation but may be performed either before or after it has been tied-in to the pipeline. If injurious defects that are an integrity threat are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with applicable part 192 requirements for a fabricated unit or with the applicable ASME BPVC requirements referenced in paragraphs (a) or (b) of this section. Test, inspection, and repair records for the fabricated unit or pressure vessel must be kept for the operational life of the component. Test records must meet the requirements in § 192.517(a).

(4) An initial pressure test from the prefabricated unit or pressure vessel manufacturer may be used to meet the requirements of this section with the following conditions:

(i) The prefabricated unit or pressure vessel is newly-manufactured and installed on or after October 1, 2021, except as provided in paragraph (e)(4)(ii) of this section.

(ii) An initial pressure test from the fabricated unit or pressure vessel manufacturer or other prior test of a new or existing prefabricated unit or pressure vessel may be used for a component that is temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. The temporary component must be promptly removed after that task is completed. If operational and environmental constraints require leaving a temporary prefabricated unit or pressure vessel under this paragraph in place for longer than 30 days, the operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with § 192.18.

(iii) The manufacturer's pressure test must meet the minimum requirements of this part;
and

(iv) The operator inspects and remediates the prefabricated unit or pressure vessel after installation in accordance with paragraph (e)(3)(ii) of this section.

(5) An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement, and then reinstalled at the same location must be inspected in accordance with paragraph (e)(3)(ii) of this section; however, a new pressure test is not required provided no damage or threats to the operational integrity of the prefabricated unit or pressure vessel were identified during the inspection and the MAOP of the pipeline is not increased.

(6) Except as provided in paragraphs (e)(4)(ii) and (5) of this section, on or after October 1, 2021, an existing prefabricated unit or pressure vessel relocated and operated at a different location must meet the requirements of this part and the following:

(i) The prefabricated unit or pressure vessel must be designed and constructed in accordance with the requirements of this part at the time the vessel is returned to operational service at the new location; and

(ii) The prefabricated unit or pressure vessel must be pressure tested by the operator in accordance with the testing and inspection requirements of this part applicable to newly installed prefabricated units and pressure vessels.

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993 with Amdt. 192-68 Correction, 58 FR 45268, Aug. 27, 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; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

This guide material is under review following Amendment 192-128.

Section 192.153(e) requires that certain components, subject to the strength testing requirements of §192.505(b), be tested to at least 1.5 times the MAOP. It is the operator's responsibility to ensure that a component is tested in accordance with §192.153(e) by communicating design, specification, and testing requirements to the manufacturer or fabricator of the component. For pipelines operating below 30% SMYS, the operator might consider adopting specifications requiring strength testing of all components to at least 1.5 times the MAOP.

§192.155

Welded branch connections.

[Effective Date: 11/12/70]

Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, must be designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.

GUIDE MATERIAL

REINFORCEMENT OF WELDED BRANCH CONNECTIONS

1 GENERAL CONSIDERATIONS

The following paragraphs provide design recommendations for the usual combinations of loads, exclusive of excessive external loads.

1.1 Reinforcement rule.

The reinforcement in the crotch section of a welded branch connection should be determined by the rule that the metal area available for reinforcement be equal to or greater than the recommended area defined in 1.2 below as well as in Guide Material Appendix G-192-4, Figure 192.155A.

1.2 Recommended cross-sectional area.

The recommended cross-sectional area A_R is defined as the product of d times t :

$$A_R = d \times t$$

Where:

- d = Length of the finished opening in the header wall measured parallel to the axis of the run.
- t = Nominal header wall thickness as specified in §192.105. When the pipe wall thickness includes an allowance for corrosion or erosion, all dimensions used should be those that will result after the anticipated corrosion or erosion has taken place.

1.3 Area available for reinforcement.

The area available for reinforcement should be the sum of:

- (a) The cross-sectional area resulting from any excess thickness available in the header thickness (over the minimum recommended for the header as defined in 1.2 above) and which lies within the reinforcement area as defined in 1.4 below.
- (b) The cross-sectional area resulting from any excess thickness available in the branch wall thickness (over the minimum thickness recommended for the branch and which lies within the reinforcement areas as defined in 1.4 below)
- (c) The cross-sectional area of all added reinforcing metal that lies within the reinforcement area, as defined in 1.4 below, including that of solid weld metal which is conventionally attached to the header or branch or both.

1.4 Area of reinforcement.

The area of reinforcement is shown in Guide Material Appendix G-192-4, Figure 192.155A and is defined as a rectangle whose length extends a distance (d) on each side of the transverse centerline of the finished opening and whose width extends a distance of $2\frac{1}{2}$ times the header wall thickness on each side of the surface of the header wall, except that in no case should it extend more than $2\frac{1}{2}$ times the thickness of the branch wall from the outside surface of the header or of the reinforcement, if any.

1.5 Stress correction factor for reinforcement area.

The material of any added reinforcement should have an allowable working stress at least equal to that of the header wall, except that material of lower allowable stress may be used if the area is increased in direct ratio of the allowable stresses for header and reinforcement material respectively.

1.6 Pad or saddle reinforcement material.

- (a) The material used for pad or saddle reinforcement may be of specifications differing from those of the pipe, provided the cross-sectional area is made in correct proportion to the relative strength of the pipe and reinforcement materials at the operating temperatures, and provided it has welding qualities comparable to those of the pipe. No credit should be taken for the additional strength of material having a higher strength than that of the part to be reinforced.
- (b) When pads or saddles are used which cover the weld between branch and header, a vent hole should be provided in the ring or saddle to reveal leakage in the weld between the branch and header and to provide venting during welding and heat treating operations. Vent holes should be plugged during service to prevent crevice corrosion between the pipe and reinforcing member, but no

- plugging material should be used that would be capable of sustaining pressure within the crevice.
- (c) Reinforcement pads and saddles should be accurately fitted to the parts to which they are attached. Some acceptable forms of reinforcement are illustrated in Guide Material Appendix G-192-4, Figures

192.155C and 192.155D.

1.7 *Ribs or gussets.*

The use of ribs or gussets should not be considered as contributing to reinforcement of the branch connection. Ribs or gussets may be used for purposes other than reinforcement, such as stiffening.

1.8 *Branch attachments.*

- (a) The branch should be attached by a weld for the full thickness of the branch or header wall plus a fillet weld W_1 as shown in Guide Material Appendix G-192-4, Figures 192.155B and 192.155C. The use of concave fillet welds is preferred to further minimize corner stress concentration. Pad or saddle reinforcement should be attached as shown in Guide Material Appendix G-192-4, Figure 192.155C. When a full fillet is not used, it is recommended that the edge of the reinforcement be relieved or chamfered at approximately 45 degrees to merge with the edge of the fillet.
- (b) Branch connections attached at an angle less than 85 degrees to the run become progressively weaker as the angle becomes less. Any such design should be given individual study, and sufficient reinforcement provided to compensate for the inherent weakness of such construction. The use of encircling ribs to support the flat or reentering surfaces is acceptable, and may be included in the strength calculations. The designer is cautioned that stress concentrations near the ends of partial ribs, straps, or gussets may defeat their reinforcing benefit.

2 REINFORCEMENT OF MULTIPLE OPENINGS

2.1 *General.*

When two or more adjacent branches are spaced at less than 2 times their average diameter (so that their effective areas of reinforcement overlap), the group of openings should be reinforced in accordance with the recommendations of 2.1, 2.2, and 2.3 of this guide material. The reinforcing metal should be added as a combined reinforcement, the strength of which should equal the combined strengths of the reinforcements determined for the separate openings. In no case should any portion of a cross section be considered to apply to more than one opening or be evaluated more than once in a combined area.

2.2 *Consideration of distance between centers.*

- (a) When more than two adjacent openings are to be provided with a combined reinforcement, the minimum distance between centers of any two of these openings should preferably be at least $1\frac{1}{2}$ times their average diameter, and the area of reinforcement between them should be at least equal to 50% of the total determined for these two openings on the cross section being considered.
- (b) When the distance between the centers of two adjacent openings, as considered under 2.2 above, is less than $1\frac{1}{3}$ times their average diameter, no credit for reinforcement should be given for any of the metal between these two openings.

2.3 *Treatment as one assumed opening.*

Any number of closely spaced adjacent openings, in any arrangement, may be reinforced as if the group was one opening of a diameter enclosing all the openings.

3 SPECIAL CONSIDERATIONS

In addition, branch connections should comply with the Special Considerations given in Table 192.155i.

REINFORCEMENT OF WELDED BRANCH CONNECTIONS: SPECIAL CONSIDERATIONS			
Ratio of Design Hoop Stress to Minimum Specified Yield Strength in Header (R_1)	Ratio of Nominal Branch Diameter to Nominal Header Diameter (R_2)		
	$R_2 \leq 25\%$	$25\% < R_2 \leq 50\%$	$50\% < R_2$
$R_1 \leq 20\%$	G	G	H
$20\% < R_1 \leq 50\%$	D,I	I	H,I
$50\% < R_1$	C,D,E	B,E	A,E,F

TABLE 192.155i

3.1 Special Consideration A.

Smoothly contoured, wrought-steel tees of proven design are preferred. When tees cannot be used, the reinforcing member should extend around the circumference of the header. Pads, partial saddles, or other types of localized reinforcement should not be used.

3.2 Special Consideration B.

Smoothly contoured tees of proven design are preferred. When tees are not used, the reinforcing member should be of the complete encirclement type, but may be of the pad type, saddle type, or a welding outlet fitting.

3.3 Special Consideration C.

The reinforcement member may be of the complete encirclement type, pad type, saddle type or welding outlet fitting type. The edges of reinforcement members should be tapered to the header thickness. It is recommended that legs of fillet welds joining the reinforcing members and header do not exceed the thickness of the header.

3.4 Special Consideration D.

Reinforcement calculations are not normally made for openings 2 inches and smaller in diameter. However, care should be taken to provide suitable protection against vibrations and other external forces to which these small openings are frequently subjected.

3.5 Special Consideration E.

All welds joining the header, branch and reinforcing members should be equivalent to those shown in Guide Material Appendix G-192-4, Figures 192.155B and 192.155C.

3.6 Special Consideration F.

The inside edges of the finished opening should, whenever possible, be rounded to a 1/8-inch radius. If the encircling member is thicker than the header and is welded to the header, the ends should be tapered down to the header thickness and continuous fillet welds should be made.

3.7 Special Consideration G.

Consideration should be given to reinforcement of openings in special cases, such as pressures over

100 psi, thin-wall pipe, or severe external loads.

3.8 Special Consideration H.

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

3.9 Special Consideration I.

The reinforcement may be of any type included in this guide material.

§192.157
Extruded outlets.

[Effective Date: 11/12/70]

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

GUIDE MATERIAL

1 GENERAL

1.1 Applicability.

- (a) The recommendations below apply to steel extruded outlets in which the reinforcement is integral. An extruded outlet is defined as an outlet in which the extruded lip at the outlet has a height above the surface of the run which is equal to or greater than the radius of curvature of the external contoured portion of the outlet: i.e., $h_0 \geq r_0$. For nomenclature, see Guide Material Appendix G-192-4, Figures 192.157A, B, C, and D.
- (b) These recommendations do not apply to any nozzles or branch connections in which additional non-integral material is applied in the form of rings, pads, or saddles.
- (c) These recommendations apply only to cases where the axis of the outlet intersects and is perpendicular to the axis of the run.
- (d) Pertinent dimensions and limiting conditions are defined in Guide Material Appendix G-192-4, Figures 192.157A, B, C, and D.

1.2 Marking.

In addition to the material contained herein, the manufacturer should be responsible for establishing, in accordance with Part 192, the design pressure and temperature. The manufacturer's name or trademark and the design pressure and temperature should be marked on the section.

2 CALCULATIONS

2.1 Recommended area.

The recommended area is defined as $A = K (t_r \times D_0)$ where K shall be taken as follows:

$$K = \begin{cases} 1.00 & 0.60 < \frac{d}{D} \\ 0.6 + 2 / 3x \frac{d}{D} & 0.15 < \frac{d}{D} \leq 0.60 \\ 0.70 & \frac{d}{D} \leq 0.15 \end{cases}$$

The design should meet the criteria that the reinforcement area defined in 2.2 below is not less than the recommended area.

2.2 Reinforcement area.

The reinforcement area should be the sum of areas $A_1 + A_2 + A_3$ as defined below:

- (a) *Area A_1* - The area lying within the reinforcement zone resulting from any excess thickness available in the run wall: i.e.,

$$A_1 = D_0 (T_r - t_r)$$

- (b) *Area A_2* - The area lying within the reinforcement zone resulting from excess thickness available in the branch pipe wall: i.e.,

$$A_2 = 2L (T_b - t_b)$$

- (c) *Area A_3* - The area lying within the reinforcement zone resulting from excess thickness available in the extruded outlet lip: i.e.,

$$A_3 = 2r_0 (T_0 - T_b)$$

2.3 Reinforcement of multiple openings.

The design recommendation in the guide material under §192.155 should be referred to except that the recommended area and reinforcement area should be as given in the guide material under §192.157.

3 OTHER

Extruded outlets manufactured in compliance with MSS SP-75 are in accord with 1 and 2 above.

§192.159

Flexibility.

[Effective Date: 11/12/70]

Each pipeline must be designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

GUIDE MATERIAL

1 STEEL

1.1 Applicability.

These recommendations are applicable only to above ground steel piping for temperatures through 450

°F.

1.2 *Amount of expansion.*

The thermal expansion of the more common materials used for piping should be determined from Table 192.159i of this guide material. The expansion to be considered is the difference between the expansion for the maximum expected operating temperature and that for the expected average erection temperature. For materials not included in this table, or for precise calculations, reference should be made to authoritative source data, such as publications of the National Bureau of Standards.

THERMAL EXPANSION OF CARBON AND LOW-ALLOY, HIGH-TENSILE STEEL AND WROUGHT-IRON PIPING	
Temperature Degree F	Total expansion in inches per 100 feet above 32 °F
32	0.0
60	0.2
100	0.5
125	0.7
150	0.9
175	1.1
200	1.3
225	1.5
250	1.7
300	2.2
350	2.6
400	3.0
450	3.5

TABLE 192.159i

1.3 *Flexibility requirements.*

- (a) Formal calculations should be required only where reasonable doubt exists as to the adequate flexibility of the system.
- (b) Flexibility should be provided by the use of bends, loops, or offsets, or provisions should be made to absorb thermal changes by the use of expansion joints or couplings of the slip joint type or expansion joints of the bellows type. If expansion joints are used, anchors or ties of sufficient strength and rigidity should be installed to provide for end forces due to fluid pressure and other causes.
- (c) In calculating the flexibility of a piping system, the system should be treated as a whole. The significance of all parts of the line and all restraints, such as solid supports or guides, should be considered.
- (d) Calculations should take into account stress intensification factors found to exist in components other than plain straight pipe. Credit may be taken for the extra flexibility of such components. In the absence of more directly applicable data, the flexibility factors and stress intensification factors shown in ASME B31.3, Appendix D may be used.
- (e) Properties of pipe and fittings for these calculations should be based on nominal dimensions, and the joint factor *E* should be taken as 1.00.
- (f) Whether piping is cold sprung or not, the total range in temperature should be used in all expansion

calculations. In addition to the expansion of the line itself, the linear and angular movements of the equipment to which it is attached should be considered.

1.4 Cold springing.

In order to modify the effect of expansion and contraction, runs of pipe may be cold sprung. Cold spring may be taken into account in the calculations of the reaction as shown in 1.5 (f) below, provided an effective method of obtaining the designed cold spring is specified and used.

Flexibility calculations should be based on the modulus of elasticity E_c at ambient temperature.

1.5 Combined stress calculations.

- (a) Using the above assumptions, the stresses and reactions due to expansion should be investigated at all significant points.
- (b) The expansion stresses should be combined in accordance with the following formula:

$$S_E = \sqrt{S_b^2 + 4S_t^2}$$

Where:

S_E = Maximum computed expansion stress, psi

$S_b = iM_b/Z$ = Resultant bending stress, psi

$S_t = M_t/2Z$ = Torsional stress, psi

i = Stress intensification factor (see ASME B31.3, Appendix D)

M_b = Resultant bending moment, pound inches

M_t = Torsional moment, pound inches

Z = Section modulus of pipe, inches³

- (c) Subject to the further limitation of 1.5 (d) and (e) below, the maximum computed expansion stress, S_E , should not exceed $0.72S$. (S is the specified minimum yield strength, psi.)
- (d) The total of the following should not exceed the specified minimum yield strength, S :
 - (1) The maximum computed expansion stress, S_E .
 - (2) The longitudinal pressure stress.
 - (3) The longitudinal bending stress due to external loads, such as weight of pipe and contents and the wind.
- (e) The sum of (d)(2) and (d)(3) should not exceed 75% of the allowable stress in the hot condition:

$$(S \times F \times T)$$

Where:

S = Specified minimum yield strength, psi

F = Design factor determined in accordance with §192.111

T = Temperature derating factor in accordance with §192.115

- (f) The reactions R' should be obtained as follows from the reactions R derived from the flexibility calculations and should not exceed limits which the attached equipment or anchorage is designed to sustain.

$$R' = \begin{cases} (1 - 2/3 C_s)R & 0 \leq C_s \leq 0.6 \\ C_s R & 0.6 \leq C_s \leq 1.0 \end{cases}$$

Where:

C_s = Cold spring factor varying from zero for no cold spring to 1.0 for 100% cold spring

R = Range of reactions corresponding to the full expansion range based on E_c

E_c = Modulus of elasticity in the cold condition

2 PLASTIC

See guide material under §§192.281 and 192.321.

3 OTHER MATERIALS

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

§192.161 Supports and anchors.

[Effective Date: 02/22/88]

- (a) Each pipeline and its associated equipment must have enough anchors or supports to—
 - (1) Prevent undue strain on connected equipment;
 - (2) Resist longitudinal forces caused by a bend or offset in the pipe; and
 - (3) Prevent or damp out excessive vibration.
- (b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents.
- (c) Each support or anchor on an exposed pipeline must be made of durable, non-combustible material and must be designed and installed as follows:
 - (1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted.
 - (2) Provision must be made for the service conditions involved.
 - (3) Movement of the pipeline may not cause disengagement of the support equipment.
- (d) Each support of an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following:
 - (1) A structural support may not be welded directly to the pipe.
 - (2) The support must be provided by a member that completely encircles the pipe.
 - (3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference.
- (e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline.
- (f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988]

GUIDE MATERIAL

1 COMPRESSION OR SLEEVE-TYPE COUPLINGS

Compression or sleeve-type couplings used in exposed piping should be designed and installed so that the joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping. If such provision is not made in the manufacture of the coupling, suitable bracing or strapping should be provided, but such design should not interfere with the normal performance of the coupling or with its proper maintenance.

2 WELDING SUPPORTS OR ANCHORS TO PIPE

Structural supports or anchors may be welded directly to the pipe that is designed to operate at a hoop stress of less than 50% of the specified minimum yield strength. Proportioning and welding strength requirements of such attachments should conform to standard structural practice.

3 NEED FOR ANCHORS AS A FUNCTION OF SOIL RESTRAINT FRICTION

Where there is doubt as to the adequacy of restraint friction of the soil in which piping is buried, anchors should be designed and installed at bends or offsets.

4 BEARING AT A BEND

If buried pipe is anchored by bearing at the bend, care should be taken to distribute the load on the soil so that the bearing pressure is within safe limits for the soil involved.

5 LONGITUDINAL PULLOUT FORCE

Buried pipe joints that are close to the points of thrust origin should be designed to sustain the longitudinal pullout force. If such provision is not made in the manufacture of the joints, suitable bracing or strappings should be provided.

6 CONNECTIONS IN A CONSOLIDATED BACKFILL

When openings are made in a consolidated backfill to connect new branches to an existing pipeline, care should be taken to provide firm foundation for both the header and the branch.

7 BLOWDOWN DISCHARGE SUPPORTS

The gas jetting out of a blowdown discharge can exert considerable forces on a piping system. Structural supports may be required to prevent vertical and lateral movement of the piping system. Soil mechanics should be considered in determining the support capability of the ground under the thrust supports.

§192.163

Compressor stations: Design and construction.

[Effective Date: 03/06/15]

(a) *Location of compressor building.* Except for a compressor building on a platform located offshore or in inland navigable waters, each main compressor building of a compressor station must be located on property under the control of the operator. It must be far enough away from adjacent property, not under control of the operator, to minimize the possibility of fire being communicated to the compressor building from structures on adjacent property. There must be enough open space around the main compressor building to allow the free movement of fire-fighting equipment.

(b) *Building construction.* Each building on a compressor station site must be made of noncombustible materials if it contains either —

(1) Pipe more than 2 inches (51 millimeters) in diameter that is carrying gas under pressure;

or

(2) Gas handling equipment other than gas utilization equipment used for domestic purposes.

(c) **Exits.** Each operating floor of a main compressor building must have at least two separated and unobstructed exits located so as to provide a convenient possibility of escape and an unobstructed passage to place of safety. Each door latch on an exit must be of a type that can be readily opened from the inside without a key. Each swinging door located in an exterior wall must be mounted to swing outward.

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

(e) **Electrical facilities.** Electrical equipment and wiring installed in compressor stations must conform to the NFPA-70, so far as that code is applicable.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; 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

1 BUILDING CONSTRUCTION (§192.163(e))

- (a) Noncombustible as applied to a building construction material means a material which, in the form in which it is used, falls in one of the following groups (a) through (c):
- (1) Materials no part of which will ignite when subjected to fire. Examples: asbestos fiber, brick, clay tile, concrete, glass, gypsum, iron, Portland cement, slate, steel, and stone. Any material that liberates flammable gas when heated to any temperature up to 1,380 °F, for five minutes is not considered noncombustible within the meaning of this paragraph.
 - (2) Materials having a structural base of noncombustible material, as defined in (a), with a surfacing not over 1/8 inch thick which has a flame spread rating not higher than 50. Examples: certain types of protected steel sheets, gypsum wallboard.
 - (3) Materials in the form and thickness used, other than as described in (a) or (b), having a flame spread not higher than 25 without evidence of continued progressive combustion and of such composition that surfaces that would be exposed by cutting through the material in any way would not have a flame spread rating higher than 25 without evidence of continued progressive combustion.
- (b) Any material that is subject to increase in combustibility or flame spread rating through the effects of age, moisture or other atmospheric condition, beyond the limits established above, is not classified as noncombustible. Flame spread rating as used herein refers to ratings obtained according to UL 723, "Test for Surface Burning Characteristics of Building Materials"; NFPA 224, "Homes and Camps in Forest Areas (Discontinued)"; and ASTM E84, "Test Method for Surface Burning Characteristics of Building Materials." The rating is an indication of the burning characteristics of a material and is derived in comparison with untreated red oak boards as 100.
- (c) Fire hazard classifications (including flame spreads, fuel contributed and smoke developed) for various building materials may be obtained from Building Materials Directory - Underwriters' Laboratories, Inc. Also, fire resistance ratings for many floors, roofs, beams, columns, and walls may be obtained from Fire Resistance Index - Underwriters' Laboratories, Inc.

2 CLASSIFICATION OF HAZARDOUS LOCATIONS FOR ELECTRICAL INSTALLATIONS (§192.163(e))

References for the definitions, or classification, of hazardous locations are as follows.

- (a) NFPA 70, "National Electrical Code," Article 500 (see §192.7 for IBR).

- (b) API RP 500, "Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Division 1 and Division 2," Paragraph 4.2.
- (c) AGA XL1001, "Classification of Locations for Electrical Installations in Gas Utility Areas.

§192.165

Compressor stations: Liquid removal.

[Effective Date: 10/01/15]

- (a) Where entrained vapors in gas may liquefy under the anticipated pressure and temperature conditions, the compressor must be protected against the introduction of those liquids in quantities that could cause damage.
- (b) Each liquid separator used to remove entrained liquids at a compressor station must —
 - (1) Have a manually operable means of removing these liquids.
 - (2) Where slugs of liquid could be carried into the compressors, have either automatic liquid removal facilities, an automatic compressor shutdown device, or a high liquid level alarm; and
 - (3) Be manufactured in accordance with section VIII ASME Boiler and Pressure Vessel Code (BPVC) (incorporated by reference, see §192.7) and the additional requirements of §192.153(e) except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

[Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

- (a) Liquid separators that are installed in compressor station piping to protect the compressor from the introduction of liquid in quantities that could cause damage should be designed in accordance with §192.165(b)(1), (2) and (3).
- (b) When liquid removal facilities (e.g., pigging receiver tanks, slug catchers, drips and sumps) are installed in the pipeline outside the compressor station piping, they should be designed as fabricated assemblies rather than as part of the station piping.

§192.167

Compressor stations: Emergency shutdown.

[Effective Date: 07/13/98]

- (a) Except for unattended field compressor stations of 1,000 horsepower (746 kilowatts) or less, each compressor station must have an emergency shutdown system that meets the following:
 - (1) It must be able to block gas out of the station and blow down the station piping.
 - (2) It must discharge gas from the blowdown piping at a location where the gas will not create a hazard.
 - (3) It must provide means for the shutdown of gas compression equipment, gas fires, and electrical facilities in the vicinity of gas headers and in the compressor building, except, that—
 - (i) Electrical circuits that supply emergency lighting required to assist station personnel in evacuating the compressor building and the area in the vicinity of the gas headers must remain energized; and
 - (ii) Electrical circuits needed to protect equipment from damage may remain energized.
 - (4) It must be operable from at least two locations, each of which is—

- (i) Outside the gas area of the station;
 - (ii) Near the exit gates, if the station is fenced, or near emergency exits, if not fenced;
- and

(iii) Not more than 500 feet (153 meters) from the limits of the station.

(b) If a compressor station supplies gas directly to a distribution system with no other adequate source of gas available, the emergency shutdown system must be designed so that it will not function at the wrong time and cause an unintended outage on the distribution system.

(c) On a platform located offshore or in inland navigable waters, the emergency shutdown system must be designed and installed to actuate automatically by each of the following events:

(1) In the case of an unattended compressor station—

(i) When the gas pressure equals the maximum allowable operating pressure plus 15 percent; or

(ii) When an uncontrolled fire occurs on the platform; and

(2) In the case of a compressor station in a building—

(i) When an uncontrolled fire occurs in the building; or

(ii) When the concentration of gas in air reaches 50 percent or more of the lower explosive limit in a building which has a source of ignition.

For the purpose of paragraph (c)(2)(ii) of this section, an electrical facility that conforms to Class 1, Group D of the National Electrical Code is not a source of ignition.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 EMERGENCY SHUTDOWN SYSTEMS

Gas pipeline facilities that are subject to the emergency shutdown (ESD) requirements are limited to those that are part of a compressor station. The purpose of an actuated ESD is to safely deactivate the compressor station if a hazardous condition (e.g., fire, gas leak) is detected. Safe deactivation should include:

- (a) Eliminating sources of ignition (except for electrical circuits required for emergency evacuation or for protecting equipment); and
- (b) Isolating compressor station piping from fuel sources, eliminating as much fuel as practicable in a time frame defined by the operator.

Using ESD systems for other than intended purposes could result in a malfunction or unintentional activation. If the compressor station is the primary supply of gas for a distribution system, the ESD must be designed to prevent an unintended outage to customers (§192.167(b)).

1.1 Compressor station boundaries.

- (a) The term *compressor station* is often associated with the fenced area or property that contains facilities associated with mechanically boosting the gas pressure in the pipeline. Facilities not associated with boosting gas pressure (e.g., regulation or meter stations, interconnecting facilities with another operator, pig launching/receiving facilities, warehousing) are not uncommon within the station area. However, for complying with the requirements in Part 192 related to compressor stations, the *compressor station* should include only those facilities installed for the purpose of increasing the pressure of gas as it flows down the pipeline or for reducing back-pressure on upstream gas facilities to enhance flow. It includes the equipment installed for this purpose and piping, components, and appurtenances used to connect and support the equipment in the process of increasing the pressure downstream.
- (b) The operator should consider ancillary equipment that could be impacted during an ESD event. Such equipment may include the following.
 - (1) High-pressure gas piping that interconnects equipment or piping systems.
 - (2) Fuel gas systems.

- (3) Lubrication systems.
 - (4) Air systems.
 - (5) Cooling systems.
 - (6) Hydraulic systems.
- (c) Gas used for service to buildings (e.g., office, storage, warehouse) should be isolated from the gas source during an ESD but may not be required to be blown down.
Note: Boundaries of a compressor station can change over time whenever piping or equipment modifications are made to the facility. Resulting changes in station boundaries should trigger consideration for updating the ESD system to incorporate any changes in the station piping boundary.

1.2 Isolation and blowdown valves.

- (a) Isolation valves are necessary to block gas from entering the compressor station piping when an ESD is activated.
- (b) Blowdown valves are necessary for venting gas from the compressor station piping when an ESD is activated. The blowdown valves and stacks should be sized, located, and designed to accomplish the following.
 - (1) Quickly evacuate gas from the station piping.
 - (2) Minimize the venting time.
 - (3) Discharge gas into the atmosphere without undue hazard.
 - (4) Prevent detrimental accumulation of water, ice, or snow in blowdown stacks.
- (c) Isolation and blowdown valves used in an ESD should be identified on station drawings to support ESD testing and facility modifications that may require changes to the ESD system.
- (d) Operators should physically mark ESD valves (e.g., by painting them red, signage, tags) to make them clearly identifiable.

1.3 ESD actuation.

- (a) An operator may use a combination of automated devices and manual switches.
- (b) The operator should evaluate the location and type of manual ESD switches to prevent accidental operation.
- (c) Any device (manual or automated) that can be used to activate an ESD must be tested per the requirements of §192.731.

§192.169

Compressor stations: Pressure limiting devices.

[Effective Date: 11/12/70]

- (a) Each compressor station must have pressure relief or other suitable protective devices of sufficient capacity and sensitivity to ensure that the maximum allowable operating pressure of the station piping and equipment is not exceeded by more than 10 percent.
- (b) Each vent line that exhausts gas from the pressure relief valves of a compressor station must extend to a location where the gas may be discharged without hazard.

GUIDE MATERIAL

Overpressure protection devices or automatic compressor shutdown devices (e.g., transducers, software) should be installed to protect the discharge line of each compressor between the gas compressor and the first discharge block valve. The total capacity of relief devices should be equal to or greater than the capacity of that compressor.

If using overpressure protection devices on the discharge side of a compressor to protect station piping or downstream pipelines, the allowable overpressure limit is governed by the following.

- (a) 10% above the MAOP (§192.169(a)).
- (b) 75% of the SMYS of the pipe (see §192.201(a)(2)(i)).
- (c) 4% above the MAOP for a steel pipeline where the MAOP is determined under §192.620 (see §192.620(e)(1)).
- (d) For a steel pipeline with an MAOP of 60 psig or higher and covered under §192.619(c) (see §192.739(b)):
 - (1) 4% above an MAOP that produces a hoop stress over 72% SMYS.
 - (2) If the percentage of SMYS is unknown, a safe pipeline pressure considering operating and maintenance history.

§192.171

Compressor stations: Additional safety equipment.

[Effective Date: 11/12/70]

- (a) Each compressor station must have adequate fire protection facilities. If fire pumps are a part of these facilities their operation may not be affected by the emergency shutdown system.
- (b) Each compressor station prime mover, other than an electrical induction or synchronous motor, must have an automatic device to shut down the unit before the speed of either the prime mover or the driven unit exceeds a maximum safe speed.
- (c) Each compressor unit in a compressor station must have a shutdown or alarm device that operates in the event of inadequate cooling or lubrication of the unit.
- (d) Each compressor station engine that operates with pressure gas injection must be equipped so that stoppage of the engine automatically shuts off the fuel and vents the engine distribution manifold.
- (e) Each muffler for a gas engine in a compressor station must have vent slots or holes in the baffles of each compartment to prevent gas from being trapped in the muffler.

GUIDE MATERIAL

1 FUEL LINES

Fuel gas lines within a compressor station should be equipped with at least one master shut-off valve. This valve should be located at a point outside of the area or areas served, and should not be located inside a building.

2 MUFFLERS

The external shell of mufflers for engines using gas as fuel should be designed in accordance with good engineering practice and should be constructed of ductile materials.

3 STARTING AIR SYSTEMS

Items for consideration when designing compressor starting air systems include:

- (a) Air pressure, storage volume, and size of connecting piping. Each system should be adequate to rotate the engine at the cranking speed and for the number of revolutions necessary to purge the fuel gas from the power cylinders and muffler. The recommendations of the engine manufacturer may be used as a guide in determining the factors.
- (b) Number of engines installed and starting requirements. The possibility of having to start multiple engines within a short time period should be considered.
- (c) Check valve in the starting air line near each engine to prevent a backflow of fuel from the engine into the air piping system.
- (d) Check valve in the main air line on the immediate outlet side of the air tank(s), or, as an alternate, fire resistant lubricant or non-lubricated air compressors.
- (e) Air cooling equipment between the starting air compressor and air storage tanks to remove moisture and entrained oil.

4 GAS DETECTION AND ALARM SYSTEMS

The design of a gas detection system, including the number of gas detectors and their placement, should be based on compressor building configuration, manufacturer's recommendations, and prudent engineering design.

- (a) Alarms should:
 - (1) Be uniquely and immediately recognizable to personnel inside and outside the alarmed structure.
 - (2) Consider background noise and lighting in their design.
 - (3) Not be connected to devices that are activated for non-emergency purposes, such as outside telephone ringers, unless the alarm has a separate and distinguishable sound.
- (b) Considerations should include:
 - (1) Monitoring for gas in areas isolated from the compressors in and near the compressor building, such as control rooms, auxiliary rooms, and basements.
 - (2) Multiple alarm levels in the gas detection system. In addition to §192.736 requirements, a second alarm may be set at a higher percentage of LEL to activate additional alarms or the emergency shutdown (ESD) system, or both.
 - (3) Other types of detectors tied into the alarm system, such as flame or smoke alarms.

§192.173

Compressor stations: Ventilation.

[Effective Date: 11/12/70]

Each compressor station building must be ventilated to ensure that employees are not endangered by the accumulation of gas in rooms, sumps, attics, pits, or other enclosed places.

GUIDE MATERIAL

These are guidelines for ventilating compressor station buildings from gas leakage during normal operating conditions or abnormal conditions, such as a blown gasket or leaking packing gland.

1 GENERAL

- (a) Building ventilation may be by natural convection or assisted by powered fans. If ventilation is

provided by electrically powered fans, the electrical supply should remain energized even under an emergency shutdown of the gas piping. See §§192.163(e) and 192.167 regarding electrical equipment and wiring.

- (b) Consideration should also be given to installing gas detection systems for flammable or toxic gases in compressor buildings designed to alarm at predetermined levels. Such systems may activate compressor shutdown / blowdown systems or the vent louver controls. See §192.736.

2 DESIGN CONSIDERATION

- (a) In designing a ventilation system, some considerations are:
 - (1) Quality of the gas being compressed ("sweet" or "sour").
 - (2) Desired number of air changes in the room per unit of time.
 - (3) The temperature differential between the floor and ridge ventilators.
 - (4) The use of manual or motorized louvers (intake and exhaust). (If motorized: Will the ventilation system controls be tied into a gas detection system, and, will the louvers "fail open" with loss of power?)
- (b) A ventilation system should be designed to keep the percentage of gas in the building atmosphere below the Lower Explosive Limit (LEL) by an acceptable margin. If the gas stream contains toxic contaminants, specific standards should be considered, such as the Threshold Limit Value (TLV), for such contaminants in the ventilation system design.
- (c) In order to design for adequate ventilation, it is suggested that properly sized fresh air vents be located as near to the building floor as possible, and the exhaust vents as high as possible. To help eliminate the possibility of unventilated areas, fresh air vent locations should be distributed as uniformly as possible around the building. Placement of exhaust ventilation outlets should be given careful consideration, such as full ridge ventilation when utilizing a natural air convection system. Avoid the re-entrance of exhausted air by discharging as high as possible and ensuring that no window, outside air intake, or other such opening is in the path of an exhaust ventilator discharge.
- (d) If the compressor building is not equipped with a gas detection system, consideration should be given to ensuring that the ventilation louver system remains open at all times when the compressors are pressurized. In a motorized louver system, this may be provided with an interlock between the lower controls and the pressurizing or manifold valves sequencing controls. With manually operated systems, operating procedures could be established requiring louvers to be opened any time the compressors are pressurized.
- (e) Buildings, other than office buildings, located in temperate or tropical climates that are properly ventilated for heat dissipation generally do not require additional venting for gas dilution.
- (f) Additional details on ventilation practices may be obtained from the American Society of Heating, Refrigeration and Air Conditioning Engineers, Inc. (ASHRAE), and the Committee on Industrial Ventilation of the American Conference of Governmental Industrial Hygienists.

§192.175

Pipe-type and bottle-type holders.

[Effective Date: 03/24/17]

(a) Each pipe-type and bottle-type holder must be designed so as to prevent the accumulation of liquids in the holder, in connecting pipe, or in auxiliary equipment, that might cause corrosion or interfere with the safe operation of the holder.

(b) Each pipe-type or bottle-type holder must have minimum clearance from other holders in accordance with the following formula:

$$C = \frac{(3D * P * F)}{1000} \text{ in inches} \quad \left(C = \frac{(3D * P * F)}{6,895} \right) \text{ in millimeters}$$

in which:

- C = Minimum clearance between pipe containers or bottles in inches (millimeters).**
- D = Outside diameter of pipe containers or bottles in inches (millimeters).**
- P = Maximum allowable operating pressure, p.s.i. (kPa) gauge.**
- F = Design factor as set forth in §192.111 of this part.**

[Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

GUIDE MATERIAL

- (a) The definition of pipe in §192.3 includes pipe-type holders. Therefore, all requirements applicable to pipe also apply to pipe-type holders.
- (b) The definition of pipeline in §192.3 includes holders. Therefore, all requirements applicable to pipelines also apply to pipe-type and bottle-type holders.
- (c) See guide material under §192.3 for the definition of bottle, bottle-type holder, pipe-container and pipe-type holder.

§192.177
Additional provisions for bottle-type holders.
[Effective Date: 03/06/15]

- (a) Each bottle-type holder must be —
 - (1) Located on a site entirely surrounded by fencing that prevents access by unauthorized persons and with minimum clearance from the fence as follows:

Maximum allowable operating pressure	Minimum clearance feet (meters)
Less than 1,000 p.s.i. (7 MPa) gage	25 (7.6)
1,000 p.s.i. (7 MPa) gage or more	100 (31)

- (2) Designed using the design factors set forth in §192.111; and
 - (3) Buried with a minimum cover in accordance with §192.327.
- (b) Each bottle-type holder manufactured from steel that is not weldable under field conditions must comply with the following:
 - (1) A bottle-type holder made from alloy steel must meet the chemical and tensile requirements for the various grades of steel in ASTM A372/372M (incorporated by reference, see §192.7).
 - (2) The actual yield-tensile ratio of the steel may not exceed 0.85.
 - (3) Welding may not be performed on the holder after it has been heat treated or stress relieved, except that copper wires may be attached to the small diameter portion of the bottle end closure for cathodic protection if a localized thermit welding process is used.
 - (4) The holder must be given a mill hydrostatic test at a pressure that produces a hoop stress at least equal to 85 percent of the SMYS.

(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 pipeline 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.

2 BLOWDOWN RECOMMENDATIONS

2.1 Blowdown duration and timing.

- (a) The operator should minimize blowdown time by properly sizing and placing blowdown discharges to:
 - (1) Reduce the time gas is venting through a rupture and susceptible to ignition.
 - (2) Reduce the duration of a gas fire, minimizing the impact on life and property.
 - (3) Reduce the impact on flow capacity while the pipeline is out of service.
- (b) The operator should consider the following when scheduling non-emergency blowdowns for pipeline maintenance or repairs.
 - (1) Blow down during daylight hours to minimize noise emission impact on the public.
 - (2) Blow down during favorable atmospheric conditions, so that vented gas is efficiently dispersed into the atmosphere and does not travel toward potential ignition sources or populated areas.
 - (3) Provide advance notification to local residents, law enforcement, fire officials, and other pipeline operators in the area.
 - (4) Coordinate blowdowns with the operator's personnel responsible for operation of the pipeline as well as customers whose service may be impacted by the blowdowns.

2.2 Blowdown location.

The following should be considered when locating blowdown discharges.

- (a) Discharges should be located a sufficient distance away from buildings such that:
 - (1) Should vented gas ignite, buildings will not be in danger of ignition or heat damage.
 - (2) Noise emissions from blowdowns will have minimal impact on the public.
 - (3) Methane emissions from blowdowns will have minimal public and environmental impact.
- (b) Discharges should be located a sufficient distance away from overhead electric lines, and other potential ignition sources, so that the explosive gas / air concentrations of the dispersed vented gas do not come in contact with an ignition source.

2.3 Blowdown emissions.

Where practicable, operators should consider the following emission reducing actions during non-emergency blowdowns.

- (a) Reduce methane emissions for environmental and economic reasons by:
 - (1) Using existing compressor or regulator stations to pull down the pipeline pressure before blowdown.
 - (2) Using a portable evacuation compressor to pull down the pipeline pressure by pumping the gas into another pipeline before blowdown.
 - (3) Flaring the blowdown gas.
- (b) Reduce entrained liquid emissions by:
 - (1) Using blowdown separators.
 - (2) Flaring the blowdown gas.
- (c) Reduce noise emissions by using blowdown silencers, particularly in populated areas.

3 PROTECTIONS FROM TAMPERING AND DAMAGE

The operator should consider minimizing the potential risks to the system from unauthorized operation of valves. The operator should consider deterrents where practicable such as the following.

- (a) Underground vaults.
- (b) Removal of operating wheels.
- (c) Chain and locking devices.
- (d) Remote controlled valves.
- (e) Protected SCADA design for remote controlled valves.
- (f) Warning signs stating the consequences or penalties of tampering with the facility. [Suggested in OPS Advisory Bulletin ADB-2016-06 (81 FR 89183, Dec. 9, 2016; reference Guide Material Appendix G 192-1, Section 2).]

Addendum 1, June 2022

Addendum 4, May 2024

§192.181

Distribution line valves.

[Effective Date: 11/12/70]

(a) Each high-pressure distribution system must have valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.

(b) Each regulator station controlling the flow or pressure of gas in a distribution system must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.

(c) Each valve on a main installed for operating or emergency purposes must comply with the following:

(1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

(2) The operating stem or mechanism must be readily accessible.

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

GUIDE MATERIAL

1 HIGH-PRESSURE DISTRIBUTION LINE VALVES (§192.181(a))

1.1 *Physical characteristics.*

The following physical characteristics should be considered when establishing high-pressure distribution system line valve locations.

- (a) Size of area to be isolated.
- (b) Topographic features, such as rivers, major highways and railroads.
- (c) Number of valves necessary to isolate the area.

1.2 *Operating characteristics.*

The following operating characteristics should be considered when establishing locations for high-pressure distribution system line valves.

- (a) Total number of customers and such customers as hospitals, schools, commercial, and industrial users that would be affected.
- (b) Time required for available personnel to carry out isolation procedures.
- (c) Time required for controlling the pressure in the isolated area by such means as venting and transferring gas to adjacent systems.
- (d) Time required for available personnel to restore service to the customer.

2 REGULATOR STATION ISOLATION

Section 192.181(b) details the requirement for a valve on the inlet piping. When a distribution system is supplied by more than one regulator station, or when the system may reasonably be expected to create a significant backfeed, consideration should be given to isolating the stations from backfeed during an emergency. This may be accomplished by one of the following:

- (a) Installing a valve on the station outlet piping.
- (b) Utilizing valving in the distribution system to prevent a backfeed into the station.
- (c) Developing a procedure to shut down all stations supplying the system.

§192.183

Vaults: Structural design requirements.

[Effective Date: 07/13/98]

(a) Each underground vault or pit for valves, pressure relieving, pressure limiting, or pressure regulating stations, must be able to meet the loads which may be imposed upon it, and to protect installed equipment.

(b) There must be enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.

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

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

GUIDE MATERIAL

1 SUPPORTS

Equipment and piping in vaults or pits should be suitably supported by metal, masonry, or concrete supports. Control piping should be placed and supported so that its exposure to injury or damage is reduced to a minimum.

2 OPENINGS

2.1 Location.

(a) Vault or pit openings should be located so as to minimize the hazards of tools or other objects falling upon the regulator, piping or other equipment. Control piping and the operating parts of the equipment installed should not be located under an opening unless such parts are suitably protected from workers stepping on them.

(b) In designing the vault or pit to protect installed equipment, consideration should be given to incidents that may cause portions of the roof or cover to fall into the vault.

2.2 Cover.

A circular cover should be installed, or other suitable precautions should be taken, if a vault or pit opening is to be located above equipment that could be damaged by a falling cover.

3 CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

See Guide Material Appendix G-192-13.

§192.185

Vaults: Accessibility.

[Effective Date: 11/12/70]

- Each vault must be located in an accessible location and, so far as practical, away from —
- (a) Street intersections or points where traffic is heavy or dense;
 - (b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
 - (c) Water, electric, steam, or other facilities.

GUIDE MATERIAL

No guide material necessary.

§192.187

Vaults: Sealing, venting, and ventilation.

[Effective Date: 07/13/98]

Each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, must be sealed, vented or ventilated, as follows:

- (a) When the internal volume exceeds 200 cubic feet (5.7 cubic meters) —
 - (1) The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches (102 millimeters) in diameter;
 - (2) The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and
 - (3) The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.
- (b) When the internal volume is more than 75 cubic feet (2.1 cubic meters) but less than 200 cubic feet (5.7 cubic meters) —
 - (1) If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;
 - (2) If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or
 - (3) If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.
- (c) If a vault or pit covered by paragraph (b) of this section is ventilated by openings in the covers or gratings and the ratio of the internal volume, in cubic feet, to the effective ventilating area of the cover or grating, in square feet, is less than 20 to 1, no additional ventilation is required.

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

GUIDE MATERIAL

DUCTING

Where ducts are used, the outside end of the ducts should be equipped with a suitable weatherproof fitting or vent-head designed to prevent foreign matter from entering or obstructing the duct. The effective area of the openings in such fittings or vent-heads should be at least equal to the cross-sectional area of a 4 inch duct. The horizontal section of the ducts should be as short as practical and pitched to prevent the accumulation of liquids. The number of bends and offsets should be reduced to a minimum and provisions

should be incorporated to facilitate periodic cleaning. Where two ducts are employed, it may be desirable to locate one internal vent at a higher elevation than the other for improved ventilation.

§192.189

Vaults: Drainage and waterproofing.

[Effective Date: 03/06/15]

- (a) Each vault must be designed so as to minimize the entrance of water,
- (b) A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.
- (c) Electrical equipment in vaults must conform to the applicable requirements of Class 1, Group D, of the National Electrical Code, NFPA-70 (incorporated by reference, see §192.7).

[Amdt. 192-76, 61 FR 26121, May 24, 1996 with Amdt. 192-76 Correction, 61 FR 36825, July 15, 1996; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

Equipment installed in vaults should be designed to continue to operate safely if submerged.

§192.191

[Reserved]

[Effective Date: 01/22/19]

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; 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]

§192.193

Valve installation in plastic pipe.

[Effective Date: 11/12/70]

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

GUIDE MATERIAL

1 LOADING IMPOSED BY VALVE OPERATION

Common methods to prevent excessive strains in plastic pipe at valve installations include the following.

- (a) Using a valve having a low operating torque.

- (b) Anchoring the valve body to resist twisting.
- (c) Making the transition from plastic-to-metal some distance from the valve. Transition pieces approximately 2 feet long will usually provide sufficient stabilization. However, each installation should be designed to prevent excessive strain on the plastic pipe.
- (d) Installing protective sleeves, designed to mitigate the stresses imposed on the plastic pipe in the transition area between the valve and the plastic piping, should be considered if undue stresses at this joint are anticipated, or if recommended by the manufacturer. The installation of protective sleeves, in addition to providing adequate backfill and compaction around the transition area, reduces excessive bending and shear stresses. For protective sleeves, see guide material under §192.367.

2 SECONDARY STRESSES

2.1 Transitions.

The transition from plastic pipe to metal or to a more rigid section of plastic pipe should be supported by undisturbed or well-compacted soil, by bridging, or by sleeve encasement. In addition to providing adequate backfill and compaction around the transition area, the installation of protective sleeves or bridging should be considered to reduce excessive bending and shear stresses. These stresses have been known to cause premature brittle-like failures in some pre-1982 PE piping materials. For protective sleeves, see guide material under §192.367.

2.2 Valve enclosures.

Where curb boxes or other enclosures are used, they should not be supported by the plastic pipe and should not in any way impose secondary stresses on the plastic pipe.

2.3 Coiled pipe.

Valves installed in thermoplastic piping that has been coiled should be suitably restrained to prevent the rotation that may occur.

§192.195

Protection against accidental overpressuring.

[Effective Date: 11/12/70]

(a) **General requirements.** Except as provided in §192.197, each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, must have pressure relieving or pressure limiting devices that meet the requirements of §§192.199 and 192.201.

(b) **Additional requirements for distribution systems.** Each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system must—

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

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

GUIDE MATERIAL

1 GENERAL

1.1 Inlet and outlet pressure rating considerations.

Selection of inlet and outlet pressure ratings of control equipment, such as regulators and control valves, should include consideration of the following.

- (a) The maximum inlet pressure at which the regulator will perform in accordance with the manufacturer's specifications.
- (b) The maximum pressure to which the inlet may be subjected, under abnormal conditions, without causing damage to the regulator.
- (c) The maximum outlet pressure at which the regulator will perform in accordance with the manufacturer's specifications.
- (d) The maximum pressure to which the outlet may be subjected under abnormal conditions without causing damage to the internal parts of the regulator.
- (e) The maximum outlet pressure which can be safely contained by the pressure-carrying components, such as diaphragm cases, actuators, pilots and control lines.
- (f) Springs, orifices, or other parts should not be changed or modified without reevaluation of the above factors.

1.2 *Prevention of overpressuring downstream pressure-carrying components.*

Recognized methods of preventing overpressuring the downstream pressure-carrying components of control equipment include the following.

- (a) Selecting equipment rated to withstand inlet pressure on the downstream side. This is particularly important if the equipment employs internal sensing and the adjacent downstream piping is not otherwise protected.
- (b) Connecting the control or sensing line to the downstream pressure system where overpressure protection has been provided.
- (c) Protecting the downstream pressure-carrying components by installing a relief valve, regulator, back-pressure valve, or other suitable device in the control or sensing line.

1.3 Flow reversals.

Flow reversals might alter operating pressures along a transmission line from their historical norms and patterns. A review of control equipment and set points should be conducted to confirm the adequacy of existing equipment under the new operating parameters.

1.4 *Reference.*

See guide material under §192.739.

2 OVERPRESSURE PROTECTION

2.1 *Facilities that might at times be bottle-tight.*

Suitable protective devices to prevent overpressuring of facilities that might at times be bottle-tight include the following.

- (a) Spring-loaded relief valves meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 (see listing in §192.7, not IBR for §192.195).
- (b) Pilot-operated back-pressure regulators used as relief valves which are designed so that failure of the control lines will cause the regulator to open.
- (c) Rupture disks of the type meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.
- (d) Devices used to shut in natural gas wells feeding into gathering lines (e.g., well-pressure trip switches, slam shuts, Murphy switches).

2.2 *High-pressure distribution systems.*

Suitable devices to prevent overpressuring of high-pressure distribution systems include the following.

- (a) Spring-loaded relief valves meeting the provisions of the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1.
- (b) Weight-loaded relief valves.
- (c) A monitoring regulator installed in series with the primary regulator.
- (d) A series regulator set to continuously limit the pressure on the inlet of the primary regulator to not

more than the maximum allowable operating pressure of the distribution system.

- (e) An automatic shut-off device installed in series with the primary pressure regulator. The automatic shut-off device should be set to shut off when the pressure on the distribution system reaches a specified limit that does not exceed the maximum allowable operating pressure. Since this device remains closed until manually reset, it should not be used where it might cause an interruption in service to a large number of customers.
- (f) Pilot-operated back-pressure regulators used as relief valves and designed so that failure of the control lines will cause the regulator to open.
- (g) Spring-loaded diaphragm relief valves.

2.3 *Low-pressure distribution systems.*

- (a) Suitable protective devices to prevent overpressuring of low-pressure distribution systems including the following.
 - (1) A liquid-seal relief device that can be set to open accurately and consistently at the desired pressure.
 - (2) See 2.2(b) through 2.2(f) above.
- (b) There are several ways that operators can protect low-pressure distribution systems from overpressurization events. Some examples are listed in OPS Advisory Bulletin ADB-2020-02 (85 FR 61097, September 29, 2020; see Guide Material Appendix G-192-1, Section 2).
- (c) Low-pressure distribution systems that use only control lines and regulators as the means to detect and prevent overpressurization are not optimal to prevent overpressurization events. Operators should consider overpressure protection that cannot be defeated by a single operator error or equipment failure.
- (d) Operators should consider eliminating direct connections between systems operating at different pressures.
- (e) Valves connecting a higher-pressure system to a lower-pressure system should be labeled, locked closed, and clearly identified on drawings to prevent erroneous operation. The operator might consider adding the following.
 - (1) Double valves or blind plates or both to prevent leak through.
 - (2) Pressure gauge connections or sensing points on both sides of these valves.
 - (3) Relief valve downstream of the valve setting.

2.4 *Transmission lines.*

In addition to the devices listed in 2.2 above, transmission lines may incorporate other suitable means, such as the following.

- (a) Compressor overpressure protection (see guide material under §192.169).
- (b) Automatic shut off valves or other similar devices that fail closed and require a manual reset.
- (c) Rupture discs.

2.5 *Gathering lines.*

Gathering lines must use overpressure protection devices (§192.195(a)), such as those listed in 2.1, 2.2, 2.3, and 2.4 above. Overpressure protection devices could be located outside of the regulated segment.

2.6 *Other considerations.*

When bypass piping is included in the station design to facilitate maintenance or inspection of automatic overpressure protection devices, consideration should be given to the following.

- (a) Providing a regulator on the bypass piping.
- (b) Arranging the bypass piping for series regulators so that only one regulator at a time is bypassed.
- (c) When only a manually operated bypass valve is installed:
 - (1) Providing upstream and downstream pressure gauges within sight of a person operating the manual valve, and
 - (2) Specifying a manual valve that is marked with the flow direction and the operating direction to

close it.

§192.197

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

[Effective Date: 10/15/03]

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

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

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

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

(4) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.

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

(6) A self-contained service regulator with no external static or control lines

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

(c) If the maximum actual operating pressure of the distribution system exceeds 60 p.s.i. (414 kPa) gage, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

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

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

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

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

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-93,

Addendum 1, June 2022

Addendum 4, May 2024

68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

- (a) Suitable protective devices to prevent overpressuring of a customer's appliances — as a result of service regulator failure — with the conditions described in §192.197(b) include the following.
 - (1) Monitoring regulator.
 - (2) Relief valve.
 - (3) Automatic shut-off device.
- (b) The protective devices may be installed as an integral part of the service regulator or as a separate unit.

§192.199

Requirements for design of pressure relief and limiting devices.

[Effective Date: 11/12/70]

Except for rupture discs, each pressure relief or pressure limiting device must—

- (a) Be constructed of materials such that the operation of the device will not be impaired by corrosion;
- (b) Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;
- (c) Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate, and can be tested for leakage when in the closed position;
- (d) Have support made of noncombustible material;
- (e) Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, located where gas can be discharged into the atmosphere without undue hazard;
- (f) Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;
- (g) Where installed at a district regulator station to protect a pipeline system from overpressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and
- (h) Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970]

GUIDE MATERIAL

1 RUPTURE DISKS

Rupture disks should meet the requirements for design as described in the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 (see listing in §192.7, not IBR for §192.199).

2 CONTROL LINES

All control lines should be protected from falling objects, excavation, or other foreseeable causes of damage. They should be designed and installed so that damage to any one control line cannot render

both the district regulator and overpressure protective device inoperative.

3 SINGLE INCIDENT (§192.199(g))

3.1 General.

In complying with §192.199(g), the operator should evaluate each district regulating station as to the type and extent of risks that may be expected. Different locations may suggest the need for individual station design, installation considerations and the ability to perform maintenance, inspection and testing activities.

3.2 Examples.

Among the incidents that should be considered in the design of a district regulator station are the following.

- (a) Explosions or fire in vault.
- (b) Damage by vehicles.
- (c) Damage by earthmoving equipment.
- (d) Weather and environmental effects.
- (e) Others that might result from site selection with respect to airport and railroad operations.

3.3 Protection.

Design and installation considerations include the following.

- (a) General.
 - (1) Protection for relief valve stacks.
 - (2) Selection of the type of overpressure protection.
 - (3) Evaluation of the need for redundant protection.
 - (4) Inspection or maintenance activities that could compromise the integrity of normal overpressure protection. See guide material under §192.739.
- (b) Vaults.
 - (1) Use of a single vault, a double chamber vault, or vaults separated by an appropriate distance.
 - (2) Structural design. See guide material under §192.183.
- (c) Above ground installations.
 - (1) Location on property under control of the operator.
 - (2) Space around building(s) for free movement of firefighting equipment.
 - (3) Use of a single-room building, a double-room building or buildings separated by an appropriate distance.
 - (4) Use of ventilated buildings made of noncombustible materials. The roof and sidewalls should be designed to relieve the force of an explosion.
 - (5) Use of posts, guardrails, or barricades.

4 SECURITY (§192.199(h))

Recommended methods for complying with §192.199(h) include the following.

- (a) Securing the proper position of any valve under a relief valve that could make the relief valve inoperative or valves that could make the pressure regulating or limiting device ineffective, such as a bypass valve or a control line valve.
- (b) Installing duplicate relief valves, each having adequate capacity to protect the system. Isolating valves or a three-way valve should be installed so that it is mechanically impossible to render more than one safety device inoperative at a time.

5 OTHER CONSIDERATIONS TO MINIMIZE DAMAGE BY OUTSIDE FORCES

See Guide Material Appendix G-192-13.

§192.201

Required capacity of pressure relieving and limiting stations.

[Effective Date: 07/13/98]

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:

(1) In a low pressure distribution system, the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

(2) In pipelines other than a low pressure distribution system—

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

(ii) If the maximum allowable operating pressure is 12 p.s.i. (83 kPa) gage or more, but less than 60 p.s.i. (414 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 6 p.s.i. (41 kPa) gage; or

(iii) If the maximum allowable operating pressure is less than 12 p.s.i. (83 kPa) gage, the pressure may not exceed the maximum allowable operating pressure plus 50 percent.

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

(c) Relief valves or other pressure limiting devices must be installed at or near each regulator station in a low-pressure distribution system, with a capacity to limit the maximum pressure in the main to a pressure that will not exceed the safe operating pressure for any connected and properly adjusted gas utilization equipment.

[Amdt. 192-9, 37 FR 20826, Oct. 4, 1972; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL

- (a) The regulator capacity against which the relief device should protect is the maximum capacity under any single failure mode. The regulator capacity shown in the manufacturer's literature can be used, provided it is known to be the capacity of the regulator in a failed wide-open position. The capacity of the relief device should be based on the maximum capacity of the regulator at the highest pressure in the pipeline that supplies gas to the regulator. This supply pressure may be the maximum operating pressure or the maximum allowable operating pressure defined in §192.3.
- (b) The minimum demand on a system may be considered when sizing the relief device provided there is assurance that this minimum flow will always be present.
- (c) When there is parallel regulation at a station, the relief capacity for the station should be based on the assumption that the largest capacity regulator fails wide open.
- (d) Consideration should also be given to the capacity of the pipeline system supplying the station. If the pipeline is not capable of supplying the failed wide-open capacity of the largest capacity regulator, the relief capacity may be based on the maximum capacity of the pipeline system supplying the station.

2 DETERMINATION OF RELIEF DEVICE CAPACITY

- (a) When installed in accordance with the provisions of §192.199(f):
 - (1) Relief devices stamped by the manufacturer with a capacity certified under the rules of the ASME Boiler and Pressure Vessel Code, Section VIII (see listing in §192.7, not IBR for 192.201), including recertification stampings, may be considered capable of relieving the capacity stamped. An adjustment should be made to determine the capacity at actual operating conditions.
 - (2) Capacities listed in information published by the manufacturer may be used to identify the capacity of the relief device under the stated conditions.
 - (3) The use of published data or data otherwise obtained from the manufacturer, and data calculated using recognized formulas, is acceptable.
- (b) Relief device capacities as set out above are normally based on the pressure measured at the inlet to the relief device with discharge to atmosphere without vent stack piping. Therefore, when the installation is not in accordance with the provisions of §192.199(f), consideration should be given to the pressure loss in the inlet piping to the relief device, the control piping location and back pressure on the discharge side caused by vent stack piping.
- (c) References include the following:
 - (1) For the calculations in 2(a)(3) above, UG-131 of the ASME Boiler and Pressure Vessel Code, Section VIII. It is not the intent herein that the capacity be limited to 90% of the actual capacity as set out in Section VIII rules, but only that this information is useful in calculating the actual capacity of a relief device.
 - (2) For data on relief devices which have been certified by the NBB, "Relieving Capacities of Safety Valves and Relief Valves Approved by the National Board" (Discontinued).
 - (3) For the effect of backpressure on relief device discharge, Figure D-1 of API RP 520 P2, "Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part 2 Installation."

§192.203

Instrument, control, and sampling pipe and components.

[Effective Date: 07/13/98]

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

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

(1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

(2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary.

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

(4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing.

(5) Pipe or components in which liquids may accumulate must have drains or drips.

(6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning.

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

(8) Each joint between sections of pipe, and between pipe and valves or fittings, must be

made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself.

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

[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

Instrument, control, and sampling pipe and components which extend to a remote location (adjacent room or building) should be identified by color code, signs, diagrams, or other appropriate means so that proper valves can be located and operated in an emergency. At locations where the identification of such piping is obvious, color coding, marking, diagrams, etc., may not be necessary. Also, see Guide Material Appendix G-192-13 and guide material under §192.199 and 192.739.

§192.204

Risers installed after January 22, 2019.

[Effective Date: 01/22/19]

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

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

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

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

No guide material necessary.

§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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SUBPART E WELDING OF STEEL IN PIPELINES

§192.221

Scope.

[Effective Date: 11/12/70]

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

GUIDE MATERIAL

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

§192.223

(Removed.)

[Effective Date: 07/07/86]

§192.225

Welding procedures.

[Effective Date: 03/24/17]

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

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

[Amdt. 192-18, 40 FR 10181, Mar. 5, 1975; Amdt. 192-22, 41 FR 13589, Mar. 31, 1976; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-52, 51 FR 20294, June 4, 1986; Amdt. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015, Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

GUIDE MATERIAL

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

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

§192.227

Qualification of welders.

[Effective Date: 07/01/2020]

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

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

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

[Amdt. 192-18, 40 FR 10181, Mar. 5, 1975 with Amdt. 192-18A, 40 FR 27222, June 27, 1975; Amdt. 192-22, 41 FR 13589, Mar. 31, 1976; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-52, 51 FR 20294, June 4, 1986; 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. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015; Amdt. 192-123, 82 FR 7997, Jan. 23, 2017; Amdt. 192-125, Oct. 1, 2019]

GUIDE MATERIAL

- (1) It is the operator's responsibility to ensure that all welding is performed by qualified welders and welding operators.
- (2) The ability of welders and welding operators to make sound welds should be determined by test welds using previously qualified welding procedures. The evaluation of test welds may be conducted by qualified operator personnel or testing laboratories.
- (3) For steel transmission, offshore and onshore Type A gathering pipe installed after July 1, 2021, records of the qualification of each individual welder should include the following.
 - (a) Welder's identity.
 - (b) Welding procedure to which the welder is qualified.
- (4) The operator should consider identifying the specific welds produced by each individual welder and the locations of those welds in the construction records using methods such as the following.

- (a) Measurements from known landmarks.
- (b) GPS coordinates.
- (c) Station number.
- (d) Other methods.

§192.229

Limitations on welders and welding operators.

[Effective Date: 03/12/21]

(a) No welder or welding operator whose qualification is based on nondestructive testing may weld compressor station pipe and components.

(b) A welder or welding operator may not weld with a particular welding process unless, within the preceding 6 calendar months, the welder or welding operator was engaged in welding with that process. Alternatively, welders or welding operators may demonstrate they have engaged in a specific welding process if they have performed a weld with that process that was tested and found acceptable under section 6, 9, 12, or Appendix A of API Std 1104 (incorporated by reference, see § 192.7) within the preceding 7 1/2 months.

(c) A welder or welding operator qualified under §192.227(a)—

(1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder or welding operator has had one weld tested and found acceptable under either section 6, section 9, section 12 or Appendix A of API Std 1104 (incorporated by reference, see §192.7). Alternatively, welders or welding operators may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7 1/2 months. A welder or welding operator qualified under an earlier edition of a standard listed in §192.7 of this part may weld, but may not re-qualify under that earlier edition; and,

(2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder or welding operator is tested in accordance with paragraph (c)(1) of this section or re-qualifies under paragraph (d)(1) or (d)(2) of this section.

(d) A welder or welding operator qualified under §192.227(b) may not weld unless—

(1) Within the preceding 15 calendar months, but at least once each calendar year, the welder or welding operator has re-qualified under §192.227(b); or

(2) Within the preceding 7 1/2 calendar months, but at least twice each calendar year, the welder or welding operator has had—

(i) A production weld cut out, tested, and found acceptable in accordance with the qualifying test; or

(ii) For a welder who works only on service lines 2 inches (51 millimeters) or smaller in diameter, the welder has had two sample welds tested and found acceptable in accordance with the test in section III of Appendix C of this part.

[Amdt. 192-18, 40 FR 10181, Mar. 5, 1975 with Amdt. 192-18A, 40 FR 27222, June 27, 1975; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; 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. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

A welding "process" is one element of a welding "procedure." Processes commonly used in pipeline welding procedures include the following:

- (a) Shielded metal arc.
- (b) Submerged arc.
- (c) Gas tungsten arc

- (d) Gas metal arc.
- (e) Flux-cored arc.
- (f) Oxyacetylene.

<p>§192.231 Protection from weather.</p> <p style="text-align: right;"><i>[Effective Date: 11/12/70]</i></p>
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The welding operation must be protected from weather conditions that would impair the quality of the completed weld.

GUIDE MATERIAL

No guide material necessary.

<p>§192.233 Miter joints.</p> <p style="text-align: right;"><i>[Effective Date: 11/12/70]</i></p>

(a) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS may not deflect the pipe more than 3 degrees.

(b) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent, of SMYS may not deflect the pipe more than 12½ degrees and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

(c) A miter joint on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS may not deflect the pipe more than 90 degrees.

GUIDE MATERIAL

No guide material necessary.

<p>§192.235 Preparation for welding.</p> <p style="text-align: right;"><i>[Effective Date: 11/12/70]</i></p>
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Before beginning any welding, the welding surfaces must be clean and free of any material that may be detrimental to the weld, and the pipe or component must be aligned to provide the most favorable condition for depositing the root bead. This alignment must be preserved while the root bead is being deposited.

GUIDE MATERIAL

1 BUTT WELDS

- (a) Proper alignment of pipe ends must be achieved prior to and maintained during position or roll welding. (§192.235)
- (b) Spacing between abutting pipe ends should not exceed the limits specified in the welding procedure used to make the weld.
- (c) Alignment of pipe ends should minimize the offset between their surfaces. Any offsets should be uniformly distributed around the circumference of the pipe ends and be within the permissible tolerances for those pipe segments.
- (d) Proper care should be exercised during alignment to ensure that pipe joints are not placed under stress. Hammering of pipe ends to achieve alignment should be minimized.
- (e) The following may be used singularly or in combination, if needed, to ensure proper pipe alignment while the root bead is being deposited.
 - (1) Internal or external alignment clamps.
 - (2) Jack stands.
 - (3) Spirit levels and squares.
 - (4) Jigs.
 - (5) Spacers (e.g., backing rings / "chill rings").
 - (6) Cranes, hoists, or skids.
 - (7) Tack welds.
- (f) The following problems may be caused by failure to achieve and maintain proper pipe alignment during welding.
 - (1) Excessive width of the root opening.
 - (2) High-low misalignment.
 - (3) Inadequate joint penetration of the root bead.
- (g) Some acceptable end preparations are shown in Guide Material Appendix G-192-5, Figures 192.235A and 192.235B.

2 FILLET WELDS

Minimum dimensions for fillet welds used in the attachment of slip-on flanges and for socket-welded joints are shown in Guide Material Appendix G-192-5, Figure 192.235C. Similar minimum dimensions for fillet welds used in branch connections are shown in Guide Material Appendix G-192-4, Figures 192.155B and 192.155C.

3 SEAL WELDS

Where threaded joints are seal-welded, the weld should not be considered as contributing to the strength of the joint.

4 MITER WELDS

In making mitered joints, care should be taken to ensure proper groove spacing, alignment, and full penetration. In cutting miter joints, the cutting torch should be held so that the entire cut surface is in the same plane. The miter cut should be followed by a beveling cut, leaving 1/32 inch to 1/16 inch of shoulder at the inner wall. The included angle of the resultant welding groove should be at least 60 degrees.

§192.237
(Removed.)

[Effective Date: 07/07/86]

§192.239

(Removed.)

[Effective Date: 07/07/86]

§192.241

Inspection and test of welds.

[Effective Date: 10/01/15]

(a) Visual inspection of welding must be conducted by an individual qualified by appropriate training and experience to ensure that:

- (1) The welding is performed in accordance with the welding procedure; and
- (2) The weld is acceptable under paragraph (c) of this section.

(b) The welds on a pipeline to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS must be nondestructively tested in accordance with §192.243, except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if —

- (1) The pipe has a nominal diameter of less than 6 inches (152 millimeters); or
- (2) The pipeline is to be operated at a pressure that produces a hoop stress of less than 40 percent of SMYS and the welds are so limited in number that nondestructive testing is impractical.

(c) The acceptability of a weld that is nondestructively tested or visually inspected is determined according to the standards in section 9 or Appendix A of API Std 1104 (incorporated by reference, see §192.7). Appendix A of API Std 1104 may not be used to accept cracks.

[Amdt. 192-18, 40 FR 10181, Mar. 5, 1975 with Amdt. 192-18A, 40 FR 27222, June 27, 1975; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; 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. 192-94, 69 FR 32886, June 14, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-119, 80 FR 168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

1 VISUAL WELDING INSPECTION

The inspection measures listed below should be performed as applicable before, during, and after the welding process to ensure good quality workmanship for every weld made. Consideration should be given to nondestructively testing, repairing, or cutting out any weld with questionable acceptability under Section 9 of API Std 1104 (see §192.7 for IBR).

(a) Before welding:

- (1) Inspect the weld joint geometry and verify the fit-up for proper alignment.
- (2) Inspect surfaces to be welded for cleanliness.
- (3) Verify any temperature requirements for pre-heat, interpass, and post-heat treatments.
- (4) If applicable, ensure that pre-heat treatment has been properly applied.

(b) During welding:

- (1) Visually inspect the stringer (initial or root pass) bead before subsequent beads are applied. Each bead inspected should be examined for defects that may make the weld unacceptable, such as the following.

- (i) Incomplete fusion.
- (ii) Slag inclusion.
- (iii) Porosity.
- (iv) Cracks.
- (v) Undercutting.
- (vi) Bead concavity.
- (2) Verify the following.
 - (i) Interpass cleanliness.
 - (ii) Temperature requirements.
 - (iii) Weld speed.
 - (iv) Time limits between passes.
- (c) After welding:
 - (1) Inspect the configuration and dimensions of the completed weld for acceptability under the welding specification.
 - (2) If applicable, ensure that post-heat treatment has been properly applied.

2 INSPECTOR QUALIFICATIONS

- (a) An operator's welding procedures should specify the personnel who may perform visual inspection of welding, as well as the level of training and experience needed. Visual inspection may be performed by one or more of the following.
 - (1) The qualified person making the weld.
 - (2) An additional qualified welder.
 - (3) A Certified Welding Inspector (CWI).
 - (4) A qualified person who is neither a welder nor a CWI.
- (b) Visual inspection may be performed by either qualified operator personnel or qualified contract personnel.
- (c) In determining whether an individual has appropriate training and experience, consideration should be given to the following.
 - (1) Welding education or an individual's qualification examination results, if any.
 - (2) Knowledge of applicable welding processes.
- (d) The documentation of inspector qualifications should be retained.

§192.243

Nondestructive testing.

[Effective Date: 10/01/15]

- (a) **Nondestructive testing of welds must be performed by any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld.**
- (b) **Nondestructive testing of welds must be performed —**
 - (1) **In accordance with written procedures; and**
 - (2) **By persons who have been trained and qualified in the established procedures and with the equipment employed in testing.**
- (c) **Procedures must be established for the proper interpretation of each nondestructive test of a weld to ensure the acceptability of the weld under §192.241(c).**
- (d) **When nondestructive testing is required under §192.241(b), the following percentages of each day's field butt welds, selected at random by the operator, must be nondestructively tested over their entire circumference:**
 - (1) **In Class 1 locations, except offshore, at least 10 percent.**
 - (2) **In Class 2 locations, at least 15 percent.**

(3) In Class 3 and Class 4 locations, at crossing of major or navigable rivers, offshore, and within railroad or public highway rights-of way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.

(4) At pipeline tie-ins, including tie-ins of replacement sections, 100 percent.

(e) Except for a welder or welding operator whose work is isolated from the principal welding activity, a sample of each welder or welding operator's work for each day must be nondestructively tested, when nondestructive testing is required under §192.241(b).

(f) When nondestructive testing is required under §192.241(b), each operator must retain, for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-50, 50 FR 37192, Sept. 12, 1985; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

1 METHODS (§192.243(a))

The prevalent methods for through-the-wall inspection are radiographic and ultrasonic testing. For surface examination, dye penetrant or magnetic particle inspections can be used.

2 RECORDS (§192.243(f))

The required written records that are to be retained for the life of any pipeline may be in any form that documents all the required information. It is recognized that the process of obtaining and storing permanent visual records of nondestructive testing results is impractical, not feasible, or both.

§192.245

Repair or removal of defects.

[Effective Date: 11/21/83]

(a) Each weld that is unacceptable under §192.241(c) must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipeline vessel, a weld must be removed if it has a crack that is more than 8 percent of the weld length.

(b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely effect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

(c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under §192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.

[Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-46, 48 FR 48669, Oct. 20, 1983]

GUIDE MATERIAL

References for repair include the following sections of API Std 1104, "Welding of Pipelines and Related Facilities" (see listing in §192.7, not IBR for 192.245).

- (a) Section 10, "Repair and Removal of Defects."
- (b) Section B.7, "Repair and Removal of Defects" in Appendix B, "In-Service Welding."

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SUBPART F JOINING OF MATERIALS OTHER THAN BY WELDING

§192.271

Scope.

[Effective Date: 11/12/70]

(a) This subpart prescribes minimum requirements for joining materials in pipelines, other than by welding.

(b) This subpart does not apply to joining during the manufacture of pipe or pipeline components.

GUIDE MATERIAL

No guide material necessary.

§192.273

General.

[Effective Date: 11/12/70]

(a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading.

(b) Each joint must be made in accordance with written procedures that have been proven by test or experience to produce strong gastight joints.

(c) Each joint must be inspected to insure compliance with this subpart.

GUIDE MATERIAL

1 JOINT CAPABILITY

(a) The capability of a joining method should be established by test or experience. Certification by the manufacturer is acceptable in lieu of testing.

(b) All mechanical joints should be designed and installed to effectively sustain the longitudinal pull-out forces caused by contraction of the piping and by maximum anticipated external loading. For mechanical joints in plastic pipe, see 3.5 of the guide material under §192.281.

2 JOINT CLASSIFICATION

A joining method can be qualified as either equivalent to the pipe being joined or as limiting the service conditions of the pipeline.

3 WRITTEN PROCEDURES FOR JOINING

- (a) Written procedures for a joining method should include the following.
 - (1) Instruction to review the "printline" on plastic pipe to ensure that the pipe and fittings are correctly sized.
 - (2) Preparation requirements (e.g., cleaning, surface conditioning, priming, lubricating, caulking, heating) that have an impact on the capability of the joint.
 - (3) Assembly instructions, such as sequence of operations, positioning of parts, and clearances required.
 - (4) Completion limits, such as tools required, torque, hydraulic pressure, and engagement.
- (b) The procedures should be included in the installation specifications, operating procedures, and employee training materials as appropriate.

4 BOLTING

See 2 and 3 of the guide material under §192.147.

5 THREADED JOINTS

5.1 *Written procedures.*

Section 192.273(b) requires each joint to be made in accordance with written procedures (see 3 above) that have been proven by test or experience to produce strong gastight joints. In developing written procedures for threaded connections, the following should be considered.

- (a) Threaded connections other than those provided by the manufacturer should be used only on metallic pipe and fittings.
- (b) Threads should be clean before being connected.
- (c) Before re-using previously used threads, the threaded surfaces should be cleaned and inspected for wear and tear. In some cases, a thread gauge may be used to observe the fit at several points on the circumference along the thread length.
- (d) Threads exhibiting excessive wear and tear should not be re-used. Some examples of excessive wear and tear include deformation, tearing, or gouging that can interfere with the continuity or strength of the threads.
- (e) Joint compound or tape should be used in accordance with the manufacturer's directions.
- (f) The two ends should be properly aligned.
- (g) The joint should be tightened using appropriate tools to produce a gastight joint. Care should be used to protect the adjacent piping from damage while tightening.
- (h) The joint should be leak tested after completion to ensure a gastight joint.
- (i) Subpart I requires that new threaded connections on buried metallic pipe be coated and cathodically protected.

5.2 *External loading.*

- (a) Before installing metallic pipe with threaded joints, consideration should be given to the following in locations where external loading, such as frost-induced movement, can be reasonably expected.
 - (1) Using heavier-wall pipe.
 - (2) Supporting the threaded joint.
 - (3) Installing a welded joint rather than installing a threaded joint.
- (b) Stress concentration from the threads should be considered if an analysis of external loading is performed.

5.3 *Pipe size.*

Threaded metallic joints on pipe over 4 inches in diameter are difficult to assemble without leakage at these joints. Therefore, welded steel joints should be considered on pipe larger than 4 inches.

5.4 Reference.

ASME B1.20.1, "Pipe Threads, General Purpose, Inch," which includes guidance on the minimum number of threads for proper engagement.

6 MECHANICAL JOINTS IN METALLIC PIPELINES

6.1 Joint design.

Each pipeline joint employing a compression fitting should be designed and installed to accommodate potential stresses that could lead to pullout. For plastic-to-plastic and plastic-to-metal mechanical joints, see 3.5 of the guide material under §192.281.

When designing a pipeline joint using a compression fitting (e.g., coupling), an operator should consider the following.

- (a) The type of fitting, whether restrained against pullout forces up to the manufacturer's recommendation, or non-restrained.
- (b) The location of the pipeline joint relative to other pipeline components (e.g., bends, tees, end caps, other mechanical joints).
- (c) Contraction or expansion due to temperature effects, especially near a transition to aboveground piping (e.g., at a bridge crossing).
- (d) Fluctuations in internal operating pressures.
- (e) External loading, such as compaction, ground settlement, buoyancy in water, or frost heaving.
- (f) The use of pipeline anchors to resist pullout forces.
- (g) Expected tensile load (due to internal pressure and external loading) compared to the following.
 - (1) Resistance-to-pullout data for the fitting as manufactured, and
 - (2) Resistance provided by anchors, if used.
- (h) Manufacturer's pressure rating of the fitting compared to MAOP and possible future upratings.

6.2 Written procedures.

Section 192.273(b) requires that each joint be made in accordance with written procedures. Operators should ensure that the written procedures for joints using a mechanical coupling or fitting meet the manufacturer's recommendations.

7 Inspection of Joints

In accordance with §192.273(c), each joint must be inspected to ensure that the requirement to make gas-tight joints are met. Consider providing visual references such as photos, examples, or diagrams of the joint types (pipe-to-pipe and pipe-to-fitting) to the person inspecting the joint. If the joint does not appear similar to acceptable visual references, it should be removed.

§192.275

Cast iron pipe.

[Effective Date: 03/08/89]

- (a) Each caulked bell and spigot joint in cast iron pipe must be sealed with mechanical leak clamps.
- (b) Each mechanical joint in cast iron pipe must have a gasket made of a resilient material as the sealing medium. Each gasket must be suitably confined and retained under compression by a separate gland or follower ring.
- (c) Cast iron pipe may not be joined by threaded joints.
- (d) Cast iron pipe may not be joined by brazing.

[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989]

GUIDE MATERIAL

No guide material necessary.

§192.277
Ductile iron pipe.

[Effective Date: 03/08/89]

- (a) Ductile iron pipe may not be joined by threaded joints.
- (b) Ductile iron pipe may not be joined by brazing.

[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989]

GUIDE MATERIAL

No guide material necessary.

§192.279
Copper pipe.

[Effective Date: 04/19/93]

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1 of ASME/ANSI B16.5.

[Amdt. 192-62, 54 FR 5625, Feb. 6, 1989; Amdt. 192-68, 58 FR 14519, Mar. 18, 1993]

GUIDE MATERIAL

Note: Table C1 has been deleted from the 2003 edition of ASME B16.5 (see §192.7 for IBR). The same information about wall thickness and size can be found in ASME B36.10M. Reference ASME B36.10M to determine the equivalent minimum wall thickness for threading of copper pipe.

- (a) Copper pipe may be joined by a mechanical joint or a brazed or soldered lap joint. The filler material used for brazing should be a copper-phosphorous or a silver base alloy.
- (b) Butt welds should not be used for joining copper pipe or copper tubing.

§192.281
Plastic pipe.

[Effective Date: 03/12/21]

(a) **General.** A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) **Solvent cement joints.** Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM Designation D 2513-99, (incorporated by reference, see §192.7).

(3) The joint may not be heated to accelerate the setting of the cement.

(c) **Heat-fusion joints.** Each heat fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620 (incorporated by reference in § 192.7), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints, and the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature.

(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) **Adhesive joints.** Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM D 2517 (incorporated by reference, see §192.7).

(2) The materials and adhesive must be compatible with each other.

(e) **Mechanical joints.** Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

[Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Correction, 44 FR 50841, Aug. 30, 1979 and Amdt. 192-34 Correction, 44 FR 57100, Oct. 4, 1979; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-61, 53 FR 36793, Sept. 22, 1988; 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. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

1 INTRODUCTION (Plastic-to-plastic and plastic-to-metal)

To achieve sound joints in plastic piping requires skillful application of qualified procedures and the use of proper materials and equipment in good condition. Joints should be made by personnel who are qualified in the written procedures required for the type of joint involved.

2 GENERAL (Plastic-to-plastic)

Plastic piping is joined by several material-specific joining methods including solvent cement, heat fusion, and adhesives as described below. All plastic piping materials may be joined by mechanical methods. The Regulations require that the joining procedures be qualified and that joining personnel and inspectors be trained and qualified. (See §§192.281, 192.283, 192.285, and 192.287.)

3 FIELD JOINING (Plastic-to-plastic and plastic-to-metal)

3.1 Solvent cement for repairing PVC piping only. (Plastic-to-plastic)

Note: Editions of ASTM D2513 issued after 2001 no longer permit use of PVC piping for new installations, but do specify that it may be used for repair and maintenance of existing PVC gas piping. The Regulations may continue to reference an edition of ASTM D2513 earlier than 2001. The operator is advised to check §192.7 for IBR.

- (a) The solvent cement and piping components may be conditioned prior to assembly by warming, provided that it is done in accordance with the manufacturer's recommendations. Special precautions are required when the surface temperature of the material is below 50 °F or above 100 °F.
- (b) Square cut ends, free of burrs, are required for a proper socket joint. Beveling of the leading edge of the spigot end will provide for ease of insertion and better distribution of the cement.
- (c) Proper fit between the pipe or tubing and the mating socket or sleeve is essential to a good joint. Before application of cement, the pipe or tubing should freely enter the fitting but should not bottom against the internal shoulder. Sound joints cannot normally be made between components that have a loose or very tight fit.
- (d) A uniform coating of the solvent cement is required on both mating surfaces. A light coating should be applied to the socket and a heavier coating applied to the pipe or tubing. The pipe should be inserted immediately into the socket and bottomed in the socket.

For sizes greater than NPS 2, additional measures may be necessary to bottom the pipe. The completed joint should be held together for sufficient time to prevent the pipe from backing out of the fitting. After the joint is made, excess cement should be removed from the outside of the joint.

- (e) The joint should not be subject to a pressure test until it has developed a high percentage of its ultimate strength. The time required for this to occur varies with the type of cement, humidity, and temperature.
- (f) Other recommendations for making joints may be found in ASTM D2855 (for PVC), the Appendix of ASTM D2235 (for ABS), and the Appendix of ASTM D2560 (for CAB, but withdrawn 1986).

3.2 Heat fusion for PA-to-PA and PE-to-PE only by externally applied heat. (Plastic-to-plastic)

- (a) PA and PE cannot be fused to each other.
- (b) General training programs that include both printed material and slides are available from the Plastics Pipe Institute (see Guide Material Appendix G-192-1) and many manufacturers of plastic pipe.
- (c) Care should be used in the heating operation. The material should be sufficiently heated to produce a sound joint but not overheated to the extent that the material is damaged.
- (d) Square cut ends, free of burrs, are required for a proper joint.
- (e) The mating surfaces should be clean, dry, and free of material which might be detrimental to the joint.
- (f) The potential effect of drag force (the force required to initiate pipe movement) during butt fusion should be considered to ensure proper fusion pressure.
- (g) Other recommendations for making heat-fusion joints may be found in ASTM F2620, "Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings".
- (h) References for joining PA-11 or PA-12 piping are PPI TR-45, "Butt Fusion Joining Procedure for Field Joining of Polyamide-11 (PA-11) Pipe" and PPI TR-50, "Generic Butt Fusion Joining Procedure for Field Joining of Polyamide-12 (PA12) Pipe."
- (i) PE piping of different compounds or grades can be heat fused to each other. Such joining should not be undertaken indiscriminately, and should be undertaken only when qualified procedures for joining the specific compounds are used. Suggested references are as follows.
 - (1) PPI TN-13, "General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings."
 - (2) PPI TR-33, "Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe."
 - (3) PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."
- (j) Rain, cold, and windy weather conditions can influence fusion quality. Modification of the recommended heating time in the procedure should be given consideration during such conditions.

- (k) For hot taps on PE, see guide material under §192.123.
- (l) The condition of equipment for heat fusing PE must conform to the equipment manufacturer's recommended tolerances for acceptable wear of critical components. The use of damaged or worn equipment may result in fusion joints that are weak or out of alignment. The frequency of inspection should be determined by the operator based on equipment usage, equipment age and condition, and manufacturer's recommendation. See Guide Material Appendix G-192-20 for a sample inspection form.
- (m) If an operator sees bubbles in the PE pipe melt pattern during the hot-plate heat fusion process (butt fusion, socket fusion, saddle fusion) or the fusion bead has a rough, pockmarked surface appearance, this is an indication that liquid hydrocarbons might have permeated the pipe wall— see 3.2(n) below for possible moisture exception. These bubbles are formed when the liquid hydrocarbons vaporize into the melt zone during the heating process. Heat fusion joining of pipes with liquid hydrocarbon might result in voids within the joint that could adversely affect joint strength. Regardless of whether suspected liquid hydrocarbons is a result of surrounding soil environment or contents of the pipe, mechanical couplings should be considered instead of heat fusion. Further, the operator should assess the pipeline's operating conditions and determine whether an adjustment to the design pressure is necessary per the guide material under §192.121. The identification of pipe compromised by liquid hydrocarbons should be included in the abnormal operating conditions identified for the task of joining plastic pipe.
- (n) Driscopipe® 7000 and 8000 HDPE pipe high-density PE pipes on occasion are known to have moisture absorbed into the pipe wall which would form bubbles when heat is applied for heat fusion. If the operator suspects that these pipes contain moisture, the operator should contact the pipe manufacturer. An adjustment to the design pressure is not necessary per the guide material under §192.121 if moisture is present. See 3.2(m) above if there is suspicion of liquid hydrocarbon permeation.

3.3 Heat fusion by electrofusion. (Plastic-to-plastic)

- (a) Sections 192.273 and 192.283 require that procedures for making joints other than by welding be written and qualified. Each electrofusion equipment manufacturer is a source of appropriate procedures for their respective system. The operator should check state requirements on the use of electrofusion. Generally each procedure should contain some or all of the following elements:
 - (1) *Couplings.*
 - (i) The pipe should be cut at a square angle.
 - (ii) The pipe should be marked with the proper stab depth for the fitting.
 - (iii) The mating surfaces should be clean, dry, and free of material that might be detrimental to the joint.
 - (iv) Surface oxidation should be removed from the area of the pipe to be fused, up to the stab-depth marks, using the tool specified in the qualified procedure.
 - (v) One end of the pipe should be secured in an appropriate clamping device, the fitting slid onto pipe, the second piece of pipe placed into clamp, and the fitting slid to final position onto each pipe so it is properly aligned. Insertion up to the stab-depth marks should be ensured.
 - (vi) The control box should be tested for proper function.
 - (vii) The fitting should be connected to the fusion control box and the cycle activated. The fitting should be left in the clamp until cooling has been completed.
 - (viii) The joint should be inspected in accordance with §192.273.
 - (2) *Saddle fittings.*
 - (i) Determine the pipe area where the fitting is to be fused.
 - (ii) The mating surfaces should be clean, dry, and free of material that might be detrimental to the joint.
 - (iii) All surface oxidation should be removed from the pipe in the area to be fused using the tool specified in the qualified procedure.
 - (iv) The fitting should be positioned and clamped in the cleaned area.

- (v) The control box should be tested for proper function.
 - (vi) The fitting should be connected to the fusion control box and the cycle activated. The fitting should be left in the clamp until cooling has been completed.
 - (vii) The joint should be inspected in accordance with §192.273.
- (b) ASTM F1055 (see §192.7 for IBR as listed specification) and ASTM F1290, "Standard Practice for Electrofusion Joining Polyolefin Pipe and Fittings" are references for joining plastic pipe by electrofusion.
- (c) The electrofusion joining process does not allow visual examination of the pipe during the heating process to determine the presence of bubbles. If an operator suspects that liquid hydrocarbons or moisture might be present in the PE pipe, see 3.2(m) or 3.2(n) above.

3.4 Adhesive for thermosetting pipe only. (Plastic-to-plastic)

- (a) The mating surfaces should be suitably prepared and should be dry and free of material that might be detrimental to the joint.
- (b) Adhesive should be properly mixed and liberally applied on both mating surfaces. The assembled joint should be held together in alignment for sufficient time to prevent the pipe or tubing from backing out of the fitting.
- (c) The assembled joint should not be disturbed until the adhesive has properly set. The joint should not be subjected to a pressure test until it has developed a high percentage of its ultimate strength. The time required for this to occur varies with the adhesive, humidity, and ambient temperature.
- (d) To accelerate curing, an adhesive bonded joint may be heated in accordance with the manufacturer's recommendation.

3.5 Mechanical joints for all plastic piping. (Plastic-to-plastic and plastic-to-metal)

- (a) When compression type mechanical joints are used, the elastomeric gasket material in the fitting should be compatible with the plastic; that is, neither the plastic nor the elastomer should cause deterioration in chemical or mechanical properties to the other over a long period.
- (b) A stiffener is required for thermoplastic piping. The tubular stiffener required to reinforce the end of the pipe or tubing should extend at least under that section of the pipe compressed by the gasket or gripping material. The stiffener should be free of rough or sharp edges that could damage the piping. Stiffeners that fit the pipe or tube too tightly or too loosely may cause defective joining. The operator should check with the manufacturer for recommendations.
- (c) The pull-out resistance of compression-type fittings varies with the type and size of the fitting and the wall thickness of the pipe being joined. ASTM D2513 (see §192.7 for IBR as listed specification) describes requirements for three categories of mechanical fittings.
 - (1) Category 1 - full seal, full restraint. These types of mechanical fittings, when properly installed, are designed to provide a joint that is stronger than the piping being connected.
 - (2) Category 2 - full seal, no restraint.
 - (3) Category 3 - full seal, partial restraint.
- (d) For each mechanical joint, it is required that the joining procedure be qualified by the tests in §192.283(b).
- (e) Section 192.283(b)(4) requires that joints on pipe sizes less than NPS 4 must be able to withstand greater tensile forces than required to yield the plastic pipe (i.e., the pipe will yield before the mechanical joint). Joints for pipe sizes NPS 4 and greater must be able to sustain the tensile stresses as required by §192.283(b)(5). One of the methods for meeting these requirements is the use of Category 1 fittings.
- (f) In addition to using qualified joining procedures for mechanical joints as discussed in 3(d) and (e) above, the operator should consider minimizing the longitudinal pull-out forces caused by contraction of the piping and the maximum anticipated external loading. To minimize these forces, practices such as the following should be used.
 - (1) With direct burial, snaking the pipe in the ditch when the pipe is sufficiently flexible.
 - (2) With insertion in a casing, pushing the pipe into place so that it is in compression rather than tension.
 - (3) Allowing for the effect of thermal expansion and contraction of installed pipe due to seasonal

changes in temperature. The importance of this allowance increases with the length of the installation. This allowance may be accomplished by the following.

- (i) Offsets.
- (ii) Anchoring.
- (iii) Strapping the joint.
- (iv) Expansion-contraction devices.
- (v) Fittings designed to prevent pull-out (ASTM D2513, Category 1).
- (vi) Combinations of the above.

This allowance is important when the plastic pipe is used for insertion inside another pipe because it is not restrained. Coefficients of thermal expansion for thermoplastic materials determined using ASTM D696 are listed in Table 192.281i.

- (g) Some plastic pipe mechanical joints, especially those made with older metal mechanical / compression fittings, have been known to leak or pull out due to not being of a full restraint design, or due to installation errors as pointed out in OPS Advisory Bulletin ADB-08-02 (73 FR 11695, March 4, 2008; see Guide Material Appendix G-192-1, Section 2). For this reason, consider using ASTM D2513-defined Category 1 (also known as Cat 1) fittings which, by design, provide for joints in plastic gas piping that are both full restraint and full seal. Such fittings are readily available for plastic gas piping in sizes through NPS 2 and some manufacturers supply Category 1 fittings in larger sizes. If Category 1 fittings are not used, another type of qualified joining procedure is required to be used as discussed in 3.5(d) and (e) above.
- (h) When liquid hydrocarbons or moisture have permeated the PE pipe wall, see 3.2(m) or 3.2(n) above.

COEFFICIENTS OF THERMAL EXPANSION		
Pipe Material	Nominal Coefficients of Thermal Expansion ¹ (x 10 ⁻⁵ in./in.)/(°F)	Expansion (in./100 ft. pipe)/(°F increase)
PA 32312 (PA 11)	9.0	0.108
PE 2406/PE 2708	9.0	0.108
PE 3408/PE 4710	9.0	0.108
PVC 1120	3.0	0.036
PVC 2116	4.0	0.048

¹ Individual compounds may differ from the values in this table by as much as ±10%. More exact values for specific commercial products may be obtained from the manufacturer.

PA = polyamide
PE = polyethylene
PVC = poly (vinyl chloride)

TABLE 192.281i

§192.283
Plastic pipe: Qualifying joining procedures.
[Effective Date: 03/12/21]

(a) *Heat fusion, solvent cement, and adhesive joints.* Before any written procedure established under §192.273(b) is used for making plastic pipe joints by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints made according to the procedure to the following tests:

(1) The burst test requirements of —

(i) In the case of thermoplastic pipe, paragraph 6.6 (Sustained Pressure Test) or paragraph 6.7 (Minimum Hydrostatic Burst Test) of ASTM D2513–99 for plastic materials other than polyethylene or ASTM D2513–09a (incorporated by reference, see § 192.7) for polyethylene plastic materials;

(ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517 (incorporated by reference, see §192.7);

or

(iii) In the case of electrofusion fittings for polyethylene pipe (PE) and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055 (incorporated by reference, see §192.7).

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

(3) For procedures intended for nonlateral pipe connections, perform tensile testing in accordance with a listed specification. If the test specimen elongates no less than 25% or failure initiates outside the joint area, the procedure qualifies for use.

(b) *Mechanical joints.* Before any written procedure established under §192.273(b) is used for making mechanical plastic pipe joints that are designed to withstand tensile forces, the procedure must be qualified by subjecting 5 specimen joints made according to the procedure to the following tensile test:

(1) Use an apparatus for the test as specified in ASTM D638 (except for conditioning), (incorporated by reference, see §192.7).

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

(3) The speed of testing is 0.20 in (5.0 mm) per minute, plus or minus 25 percent.

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

(5) Pipe specimens 4 inches (102 mm) and larger in diameter shall be pulled until the pipe is subjected to a tensile stress equal to or greater than the maximum thermal stress that would be produced by a temperature change of 100 °F (38 °C) or until the pipe is pulled from the fitting. If the pipe pulls from the fitting, the lowest value of the five test results or the manufacturer's rating, whichever is lower must be used in the design calculations for stress.

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

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

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

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

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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. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

1 WRITTEN PROCEDURES

- (a) An operator may elect to develop joining procedures or may adopt the joining procedures developed by groups such as the Plastics Pipe Institute, ASTM, gas association, or manufacturers. The operator is responsible for ensuring that the joining procedure used is qualified in accordance with the requirements of §192.283.
- (b) Qualified joining procedures should, include images demonstrating the appearance of satisfactory joints. Written procedures for fitting installation are often packaged with each fitting.
- (c) Qualified procedures should be in the operator's installation manuals and may be printed on wallet or shirt pocket cards, or made available by other means.

2 PROCEDURE QUALIFICATION (Plastic-to-plastic and plastic-to-metal)

2.1 Procedure and qualification for joints and permanent repairs. (Plastic-to-plastic and plastic-to-metal)

- (a) Solvent cement, heat fusion, and adhesive. (Plastic-to-plastic)
 - (1) *Procedure.* A separate procedure should be established for each plastic compound and for each method of joining. The procedure specification should include the following as applicable.
 - (i) Plastic compound(s).
 - (ii) Joint design.
 - (iii) Size and thickness range.
 - (iv) Method of joining.
 - (v) Pipe and fitting preparation (e.g., scraping, peeling, facing, abrading).
 - (vi) Cleaning requirements.
 - (vii) Curing or set-up time.
 - (viii) Ambient temperature limits.
 - (ix) Temperature of the heating tool.
 - (x) Heating time.
 - (xi) Pressure.
 - (xii) Cooling time.
 - (xiii) Tools and equipment.
 - (xiv) Joining or repair technique. See 3 of the guide material under §192.281.
 - (2) *Qualification.* The procedure specification should be considered qualified if test assemblies of joints or repairs made in accordance with the procedure specification meet the requirements of 2.2 below. The test assemblies should be cured, set, or hardened in accordance with the manufacturer's recommendations.
- (b) Mechanical. (Plastic-to-plastic and plastic-to-metal)
 - (1) *Procedure.* A separate procedure should be established for each kind and type of mechanical fitting to be used for making a joint or repair. It should include at least the following.
 - (i) Kind and type of plastic material(s).
 - (ii) Other piping elements to be joined to the plastic.
 - (iii) Joint design.
 - (iv) Size and thickness range.
 - (v) Type of mechanical fitting.
 - (vi) Tools and equipment.
 - (vii) Joining and repair procedure.
 - (2) *Qualification.* To qualify the procedure specification, test assemblies of joints or repairs should be made in accordance with the procedure specifications and tested in accordance with 2.2

below. The test assemblies may be restrained to the same extent that they would be in service. These assemblies should be sectioned or dismantled to inspect for damage to the plastic pipe. The procedure should be rejected if there is evidence of damage that would reduce the service life of an installed joint or repair.

- (3) *Other considerations.* See 3.5 of the guide material under §192.281.

2.2 Test requirements. (*Plastic-to-plastic and plastic-to-metal*)

Test assemblies should successfully meet the following requirements.

- (a) Leak test. An assembly should not leak when subjected to a stand-up pressure test with air or gas.
- (b) Short-term burst test. An assembly should meet the minimum burst requirements of ASTM D2513 or ASTM D2517, whichever is applicable (see listing in §192.7, not IBR for §192.283), for the specific kind and size of plastic pipe used in the assembly.
- (c) Sustained-pressure test. An assembly should not fail when subjected to a sustained pressure test, such as the 1000 hr test described in ASTM D2513 or ASTM D2517 (whichever is applicable), for the specific kind and size of plastic pipe used in the assembly.
- (d) Tensile test. An assembly should elongate no less than 25% or failure should initiate outside the joint area when subjected to ASTM D638 testing.
- (e) Inspection. An assembly should be subjected to suitable nondestructive or destructive inspection to determine if the bonded area is substantially equivalent to the intended bond area.

3 UNLIKE PE COMPONENT QUALIFICATION

PE components made of different compounds and different grades of materials may be heat-fused, provided that properly qualified procedures for joining the specific compounds are used. Any combination of PE 2306, PE 2406/PE 2708, PE 3306, PE 3406, and PE 3408/PE 4710 may be joined by heat fusion using qualified procedures for specific materials. Operators attempting to qualify such procedures may be able to obtain qualified procedures from pipe manufacturers. (See guide material under §192.281 for PE heat fusion.) Additionally, the following references may be of assistance.

- (a) PPI TN-13, "General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings."
- (b) PPI TR-33, "Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe."
- (c) PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."

§192.285

Plastic pipe: Qualifying persons to make joints.

[Effective Date: 03/12/21]

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by —

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

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

(b) The specimen joint must be:

(1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and

(2) In the case of a heat fusion, solvent cement, or adhesive joint:

(i) Tested under any one of the test methods listed under § 192.283(a), and for PE heat fusion joints (except for electrofusion joints) visually inspected in accordance with ASTM F2620 (incorporated by reference, see § 192.7), or a written procedure that has been demonstrated to provide an equivalent or superior level of safety, applicable to the type of joint and material being tested;

(ii) Examined by ultrasonic inspection and found not to contain flaws that would cause

failure; or

(iii) Cut into at least 3 longitudinal straps, each of which is:

(A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and

(B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.

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

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

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GUIDE MATERIAL

1 OBSERVATION AND CERTIFICATION OF JOINER

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

2 CERTIFICATION RECORDS

For distribution line construction or repairs: records or qualification cards or both, which show the extent of the individual's qualifications, should be maintained for the qualification interval.

3 ULTRASONIC INSPECTION OF FUSION JOINTS

Ultrasonic inspection equipment should be capable of inspecting the internal bead for proper formation as well as detecting flaws in the fusion zone. Each manufacturer is a source of procedures for its equipment. The criteria for establishing an acceptable fusion joint must be verified by a destructive test and be repeatable. Each procedure should include the following.

- (a) Cleaning the inspection area on both sides of the fusion joint.
- (b) Using an appropriate manufacturer-approved couplant to couple the transducer to the pipe.
- (c) Inspecting the entire pipe circumference on both sides of the fusion joint.

§192.287

Plastic pipe: Inspection of joints.

[Effective Date: 07/14/04]

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

[Issued by Amdt. 192-34, 44 FR 42968, July 23, 1979 with Amdt. 192-34 Time Ext., 44 FR 50841, Aug. 30, 1979, and Amdt. 192-34 Time Ext., 44 FR 57100, Oct. 4, 1979; Amdt. 192-94, 69 FR 32886, June 14,

2004]

GUIDE MATERIAL

No guide material available at present.

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SUBPART G

**GENERAL CONSTRUCTION REQUIREMENTS
FOR TRANSMISSION LINES AND MAINS**

§192.301

Scope.

[Effective Date: 11/12/70]

This subpart prescribes minimum requirements for constructing transmission lines and mains.

GUIDE MATERIAL

No guide material necessary.

§192.303

Compliance with specifications or standards.

[Effective Date: 11/12/70]

Each transmission line or main must be constructed in accordance with comprehensive written specifications or standards that are consistent with this part.

GUIDE MATERIAL

1 GENERAL

- (a) Comprehensive written specifications or standards for constructing transmission lines, Type A, B, and C gathering lines, or mains may consist of general procedural manual and other documents (e.g., drawings, information related to contracting information) that the operator may apply generally to all construction or apply to only specific projects.
- (b) The manual for construction specifications or standards should include a written statement, procedure, or other document addressing the applicable construction requirements of Part 192 (see 2 below).
- (c) The manual can consist of multiple binders or documents with relevant sections kept at appropriate locations. Applicable sections of other documents may be referenced instead of being included, but the referenced documents should be present or available electronically at the construction location.
- (d) The length and complexity of a manual can vary depending upon the individual operator's size, locale, policies, types of construction projects, and the amount of material included in its entirety or cross-referenced, including manufacturers' instructions where appropriate.
- (e) Periodic reviews of the manual should be conducted to ensure the specifications and standards reflect current regulations and construction practices.

2 RELEVANT REQUIREMENTS

An operator should confirm that its construction specifications or standards are consistent with the specific

requirements of the applicable subparts in Part 192 including associated guide material under the following subparts:

- (a) Subpart B – Materials.
- (b) Subpart C – Pipe Design.
- (c) Subpart D – Design of Pipeline Components.
- (d) Subpart E – Welding of Steel Pipelines.
- (e) Subpart F – Joining of Materials Other than by Welding.
- (f) Subpart G – Construction Requirements for Transmission Lines and Mains.
- (g) Subpart I – Requirements for Corrosion Control.
- (h) Subpart J – Test Requirements.

3 TRAINING

Personnel performing construction operations should have a basic understanding of the elements of the construction manual that are relevant to the tasks assigned. This might include the need to establish a training program.

4 LOCATION OF SUBSTRUCTURES

For guidance on one-call and locating substructures, see guide material under §192.614.

5 EXCAVATIONS

- (a) Construction specifications or standards should address the following:
 - (1) Excavations, pavement cuts, and bores should be no larger than necessary for proper pipe installation.
 - (2) Excavations are shored or sloped as required by the operator's procedures. Osha may be helpful.
 - (3) Excavations are performed in a manner to support the pipe in direct burial excavations on undisturbed or well-compacted soil, which is rock and debris free, to provide firm support under the pipe, and to prevent excess stress during backfill.
 - (4) Proper clearance of substructures is provided to enable future maintenance and reduce the potential for damage by other facility operators.
 - (5) Caution is exercised during excavating to avoid personal injuries that could be caused by contact with other buried facilities.
 - (6) Excavation must be performed in accordance with permits. Additional transmission construction requirements may be addressed with individual permits provided by various agencies such as US Forest Service or Coast Guard.
 - (7) Transmission excavation is substantially different than distribution excavation. It is often cross-country in defined rights-of-way, with specific widths.
 - (8) FERC-approved transmission construction may have some specific requirements for placement of spoil piles.
- (b) For additional information on excavations, see guide material under §192.614.

6 BORING AND DIRECTIONAL DRILLING

See Guide Material Appendices G-192-15A and G-192-15B.

7 STRINGING AND STOCK PILING

Construction specifications or standards should address the following:

- (a) Materials laid out along the route of the pipeline should be placed in such a manner that streets, roads, sidewalks, and driveways are left open whenever practicable.
- (b) The pipe may be laid on the ground or the spoil bank, provided there is nothing in the soil on the ground or in the spoil bank that might damage the coating or plastic pipe. If the soil, ground, or spoil bank is not suitable:

- (1) Coated steel pipe should be supported clear of the spoil by skids located at the bare ends of the pipe or by devices placed under the pipe that will not damage the coating, or
- (2) Plastic pipe should be separated from the ground or spoil bank by appropriate means to minimize damage to the pipe.

8 JOINING (SUBPARTS E AND F)

Construction specifications or standards should include procedures that address joining of pipe and components.

8.1 *Welding.*

- (a) For establishing qualified welding procedures and weld preparation, see guide material under §§192.225 and 192.235.
- (b) For welding inspection, testing, and repair or removal of defects, see guide material under §§192.241, 192.243, and 192.281.

8.2 *Fusion and Mechanical Joining.*

For establishing qualified mechanical joining and fusion procedures, see guide material under §§192.273 and 192.281.

9 GENERAL CONSTRUCTION (SUBPART G)

The specifications or standards for constructing transmission lines or mains should include procedures address the following:

9.1 *Inspection of Materials.*

- (a) Section 192.307 requires that each length of pipe and each other component must be visually inspected at the job site to ensure that it has not sustained any visually detrimental damage that could impair its serviceability. The inspection should be performed by a knowledgeable representative of the operator.
- (b) Persons performing visual inspections should be alert for damages, including the following:
 - (1) Dents.
 - (2) Gouges.
 - (3) Pitting.
 - (4) Kinks.
 - (5) Out of roundness.
 - (6) Material defects.
 - (7) Lacerations of the protective coating.
- (c) The pipe and fitting markings should be reviewed to ensure that items match those specified in the construction drawings or other documents.
- (d) Repairs and replacements should be inspected before being shaded and backfilled. Shading is the rock-free backfill that is placed around the sides and top of pipe to prevent damage from rocky, surrounding backfill.
- (e) Field inspections for damage should be done during the lowering, shading, and backfill operations.
 - (1) Pipe lowered into trenches should be handled with fabric slings or other approved techniques at proper angles to prevent damage to protective coating and to prevent kinks in the pipe.
 - (2) Damage sustained by lowering operations should be repaired and reinspected before shading and backfilling the pipeline.
 - (3) Inspection of welds should be made by qualified personnel using visual and nondestructive methods approved by the operator's authorized representative.
 - (4) Coating material for steel pipelines must be visually inspected prior to lowering the pipeline into the trench and backfilling, and any damage detrimental to effective corrosion control must be repaired (§192.461(c)). A holiday detector should be used, and each holiday found should be repaired using approved materials and procedures.

9.2 *Repair of steel pipe.*

For estimating dent depth and assessing the repair of arc burns, see guide material under §192.309.

9.3 *Repair of plastic pipe.*

For the repair of plastic pipe, see guide material under §192.311.

9.4 *Bends and elbows.*

- (a) Changes of pipe direction may be made using the following methods:
- (1) Damage sustained by lowering operations should be repaired and reinspected before shading and backfilling the pipeline. Laying the pipe along the contour of the trench (i.e., roping) if the bending radius is greater than the minimum elastic bending radius allowed. Roping of PE pipe may be limited by the manufacturer's recommendations.
 - (2) Bending plastic pipe, but an operator shall not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed. (§192.313(d)).
 - (3) Approved machine bending if the minimum bending requirements are met.
 - (4) Installing weld fittings or portions of weld fittings if the requirements for welding are met.
 - (5) Installing other fittings, where appropriate.
- (b) Bends and elbows on steel transmission pipe must be signed to accommodate inline inspection (ILI) tools. (§192.150). This requirement does not apply to gathering lines. See Guide Material Appendix G-192-14.
- (c) Bends on steel pipe should be coated prior to backfilling using protective coatings approved by the operator.
- (d) Field bends in steel pipe must have a smooth contour and be free from buckling, cracks, or other mechanical damage (§192.313(a)(2)). On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend, unless the bend is made with an internal bending mandrel or the pipe is 12 inches or less in outside diameter or has a diameter to wall thickness ratio less than 70. (§192.313(a)(3)).
- (e) Each circumferential weld of steel pipe located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. (§192.313(b)).
- (f) See §192.313(c) for limitations on changes of directions using wrought-steel welding elbows and transverse segments of these elbows.
- (g) Field bends on steel pipe should be inspected and coating damage should be repaired.

9.5 *Wrinkle bends in steel pipe.*

The use of wrinkle bends in constructing new steel pipelines may be prohibited (see §192.315) and should be avoided.

9.6 *Protection from hazards.*

The operator's authorized representative should be contacted if, during construction, any of the following conditions are found along a new pipeline's alignment:

- (a) Existing parallel pipelines that have been exposed due to erosion.
- (b) The pipeline will cross areas that are normally under water or vulnerable to flooding (such as lakes, bays, swamps, and river crossings) and might require anchorage to prevent flotation.
- (c) The pipeline is being installed in an unstable bank or bed location.
- (d) An aboveground pipeline that might be vulnerable to accidental damage by vehicular traffic or other hazards.
- (e) A pipeline or pipe riser on a platform located offshore or in inland navigable waters that might be vulnerable to accidental damage by vessels.
- (f) Other unique conditions that could reasonably pose a hazard to the pipeline.

For protection from hazards, see guide material under §192.317.

9.7 *Installation of pipe in a ditch.*

For installation of pipe in a ditch or trench and trenchless installation methods such as horizontal directional drilling, see guide material under §192.319.

9.8 *Installation of plastic pipe*

For installation of plastic pipe, see guide material under §192.321.

9.9 Casing.

For the use of casing, see guide material under §192.323.

9.10 Underground clearance.

For clearance between underground transmission lines or mains and other objects, see guide material under §192.325.

9.11 Covering.

For considerations when additional cover above §192.327 minimums should be provided, see Guide Material Appendix G-192-13.

9.12 Construction requirements for steel pipe using alternative maximum allowable operating pressure.

For additional construction requirements to be eligible to operate at the alternative maximum allowable operating pressure calculated under §192.620, see guide material under §192.328.

9.13 Miter joints.

Miter joints are not recommended for steel pipelines (see §192.233 for requirements). Deflections caused by misalignment up to three degrees are generally not considered to be miters.

9.14 Dead ends.

End closures for transmission pipelines should be made using weld caps or blind flanges. See §192.153 for additional limitations on end closures.

9.15 Blasting operations near pipelines.

Pipelines should be protected from nearby blasting operations. (see Guide Material Appendix G-192-16). If blasting is required near gas pipelines, the operator's authorized representative should be contacted.

10 CORROSION CONTROL (SUBPART I)

The specifications or standards for construction of steel pipelines should include written procedures for the installation of corrosion control materials and equipment. See guide material under Subpart I for establishing corrosion control procedures. Personnel responsible for directing installation of an operator's corrosion control systems should have knowledge of and practical experience in the following, as appropriate:

- (a) Pipeline coatings.
- (b) Galvanic and impressed current cathodic protection (CP) systems.
- (c) Stray current interference.
- (d) Electrical isolation.
- (e) Survey methods and evaluation techniques.

11 PRESSURE TESTING AND PURGING (SUBPART J)

The specifications or standards for construction should include instructions for pressure testing and purging of new pipelines. See guide material under Subpart J for guidance on pressure testing and purging procedures.

12 DEVIATIONS

Deviations from the operator's written construction standards and specifications should be approved in advance by the operator's authorized representative.

13 RECORDS

- (a) Construction specifications or standards should include recordkeeping requirements for newly installed pipelines. Those requirements might relate to construction specifications, drawings, logs, charts, tracking and traceability information, and other data pertinent to the newly constructed pipeline.
- (b) Additional guidance on record keeping is provided in the guide material under §§192.243, 192.305, 192.321, 192.328, 192.476, 192.517 and Guide Material Appendix G-192-17. If construction is performed as part of a maintenance project, records must be maintained in accordance with §192.807(b)

14 REFERENCES

Additional references might be used in developing construction standards and specifications, including the following:

- (a) APWA – American Public Works Association.
- (b) CSI – Construction Specifications Institute.
- (c) ASTM Construction Standards (includes both building and roadway).
- (d) National Highway Specifications.
- (e) OSHA Standards for Trenching and Excavation.
- (f) NACE – National Association of Corrosion Engineers.
- (g) ASCE – American Society of Civil Engineers.
- (h) Manufacturer specifications or instructions.

§192.305

Inspection: General.

[Effective Date: 09/30/15]

Each transmission line or main must be inspected to ensure that it is constructed in accordance with this part.

Note: *The effective date of the amendment to 49 CFR 192.305 (as shown below), published within 80 FR 12762, March 11, 2015, is delayed indefinitely following multiple petitions for reconsideration. PHMSA will publish a document in the FEDERAL REGISTER announcing a new effective date.*

Each transmission line and main must be inspected to ensure that it is constructed in accordance with this subpart. An operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

[Amdt. 192-120, 80 FR 12762, Mar. 11, 2015 with Response to Petitions for Reconsideration, 80 FR 58633, Sept. 30, 2015]

GUIDE MATERIAL

(a) Each operator should provide inspection by personnel who are knowledgeable by training, experience, or qualification. An operator should specify requirements for the level of knowledge required for construction inspection of transmission lines, mains, or regulated gathering lines. Factors to consider in establishing these requirements include the following:

- (1) Prior experience in constructing transmission lines, mains, and regulated gathering lines.
- (2) Demonstrated knowledge of the person performing the inspection.
- (3) Training taken.
- (4) Written examination.
- (5) Qualified to the operator's Operator Qualification (OQ) program, a recognized industry OQ program, or a state-required OQ program.
- (6) Other qualifications or certifications that may be needed (e.g., NACE certification for coating inspection, API 1169 Pipeline Construction Inspector, AWS Certified Welding Inspector).

(b) Personnel performing inspection should understand of the operator's written procedures and specifications for the specific function they are assigned to inspect. Examples of operator's written procedures and specifications include the following.

- (1) Scope of the project (e.g., pipe diameter, components to be installed, length, right-of-way).
- (2) Work zone safety (e.g., traffic control, shoring, hazardous atmospheres, personal protective equipment, rigging and lifting, blasting).
- (3) Inspections of materials. See guide material under §192.307.
- (4) Repairs to steel pipe and plastic pipe during construction. See guide material under §§192.309 and 192.311.
- (5) Field modifications to pipe (e.g., bends). See guide material under §§192.313 and 192.315.
- (6) Protection from hazards. See guide material under §192.317.
- (7) Method(s) of installation (e.g., open cut, trenchless technology, insertion into casing). See guide material under §§192.319 and 192.321.
- (8) Casing installation. See guide material under §192.323.
- (9) Underground clearance and minimum cover. See guide material under §§192.325, 192.327, and Guide Material Appendix G-192-13.
- (10) Manufacturer's installation instructions for materials.
- (11) Manufacturer's tool and equipment inspection, operating and maintenance instructions (e.g., drilling, tapping, coating holiday detection).
- (12) Required work permits (e.g., federal, state, local)
- (13) One-call notification, locating, marking, and other damage prevention methods.
- (14) Environmental controls (e.g., erosion, sediment)
- (15) Verification of construction personnel qualification(s) (e.g., welding, tapping).
- (16) Excavation for correct pipeline alignment, depth, width, slope, spoil placement, and crossings (e.g., road, water).
- (17) Welding and non-destructive testing.
- (18) Corrosion control (e.g., holiday detection, coating repair, cathodic protection).
- (19) Backfilling and backfill materials. See guide material under §192.319.
- (20) Pressure testing. See guide material under §192.503.
- (21) Tie-in(s).
- (22) Additional construction requirements for steel pipelines intended to operate at an alternative MAOP. See guide material under §192.328.

(c) Inspection should ensure that work conforms to the operator's written procedures and specifications and to applicable federal, state, and local requirements.

(d) The inspector should have the authority to order the repair or the removal and replacement of any component that fails to meet the above requirements.

(e) Inspectors should report deficiencies to the operator's appropriate supervisor team in a timely manner.

(f) The operator should assemble and retain all necessary inspection records.

(g) References include the following.

- (1) "A Practical Guide for Pipeline Construction Inspectors"
www.ingaa.org/File.aspx?id=29692&v=ca234b81.

- (2) "Building Interstate Natural Gas Transmission Pipelines: A Primer"
www.ingaa.org/File.aspx?id=19618&q=Building%20Interstate%20Natural%20Gas%20Transmission%20Pipelines%20A.
- (3) "Training Guidance for Welding & Coating Workers & Inspectors"
www.ingaa.org/File.aspx?id=19350&v=3581ea0d.
- (4) API 1169, Pipeline Construction Inspection.

§192.307

Inspection of materials.

[Effective Date: 11/12/70]

Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability.

GUIDE MATERIAL

- (a) Pipe and other components used in the construction of transmission lines and mains may be exposed to possible damage during the handling and transportation required to reach the installation location. Those performing the visual inspection at the installation site should be alert for such damage. Also, care should be exercised to prevent handling damage during installation.
- (b) Field inspections for gouged or grooved pipe should be performed just ahead of the coating operation and during the lowering-in and backfill operations.
- (c) Inspection should be made to determine that the coating machine does not cause harmful gouges or grooves.
- (d) Lacerations of the protective coating should be carefully examined prior to the repair of the coating to see if the pipe surface has been damaged.
- (e) All repairs, replacements, or changes should be inspected before they are covered.
- (f) Since plastic piping and other components are susceptible to mishandling damage, special attention should be given during the installation site inspection to detect cuts, gouges, scratches, kinks, and similar imperfections

§192.309

Repair of steel pipe.

[Effective Date: 01/13/00]

(a) Each imperfection or damage that impairs the serviceability of a length of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must at least be equal to either:

(1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or

(2) The nominal wall thickness required for the design pressure of the pipeline.

(b) Each of the following dents must be removed from steel pipe to be operated at a pressure

that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe:

- (1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn.
- (2) A dent that affects the longitudinal weld or a circumferential weld.
- (3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of —
 - (i) More than 1/4 inch (6.4 millimeters) in pipe 12-3/4 inches (324 millimeters) or less in outer diameter; or
 - (ii) More than 2 percent of the nominal pipe diameter in pipe over 12-3/4 inches (324 millimeters) in outer diameter.

For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.

(c) Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent, or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either:

- (1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or
- (2) The nominal wall thickness required for the design pressure of the pipeline.

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

(e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]

GUIDE MATERIAL

1 RELIABLE ENGINEERING TESTS AND ANALYSES (§192.309(b))

See guide material under §192.485.

2 DEPTH OF A DENT (§192.309(b))

The original contour of the pipe can be estimated by placing a straight edge of sufficient length to span the dent in the longitudinal direction of the pipe. The depth is then measured at the maximum perpendicular distance between the dent and the straight edge. Examples of tools to measure the deflection include contour gauge, pit depth gauge, and calipers.

3 ARC BURNS (§192.309(c))

When the visible evidence of the arc burn has been removed by grinding, swab the ground area with 20% solution of ammonium persulfate. A blackened spot indicates that additional grinding is necessary. The complete removal of the metallurgical notch created by the arc burn has been accomplished when the swabbing does not result in a blackened spot.

§192.311

Repair of plastic pipe.

[Effective Date: 10/15/03]

Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired

or removed.

[Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

1 GENERAL

1.1 Personnel qualification.

Repairs should be made by personnel who have demonstrated the ability to make satisfactory repairs. For thermoplastic piping repairs that involve making a joint, see guide material under §192.285.

1.2 Procedure qualification.

Repairs should be made in accordance with procedures that have been qualified by making sample repairs and destructively testing those samples in accordance with established test methods. Examples of such test methods are contained in ASTM D2513 (see listing in §192.7, not IBR for §192.311). For thermoplastic piping repairs that involve making a joint, see guide material under §192.283.

1.3 Manufacturer's recommendations.

- (a) Consider the recommendations of the plastic pipe manufacturer when determining the type of repair to be made.
- (b) Give special consideration to the extent of fiber damage in the case of thermosetting plastic pipe.
- (c) Consult with the fitting manufacturer when developing the qualified repair procedure.
- (d) Ensure that the repair being made is consistent with recommendations by the fitting manufacturer.

1.4 Installation practices.

For general precautions, backfilling, and squeeze-off (including reopening), see guide material under §192.321.

2 SLEEVES AND PATCHES

2.1 Material.

- (a) The wall thickness of the patch or sleeve should be at least equal to that of the pipe.
- (b) If the repair is made by heat fusion, the patch or sleeve should preferably be the same type and grade.
- (c) If the repair is made by solvent cement, the patch or sleeve should be essentially the same type and grade.

2.2 Special considerations.

- (a) If a patch or full-encirclement sleeve is used, it should extend far enough beyond the damaged area to ensure structural integrity.
- (b) If a full-encirclement split sleeve is used, the longitudinal join line should be as far as possible from the defects, but should in no case be closer than one-half inch.

2.3 In-service piping.

For repairs to in-service piping, see guide material under §192.703.

§192.313

Bends and elbows.

[Effective Date: 01/22/19]

- (a) Each field bend in steel pipe, other than a wrinkle bend made in accordance with §192.315,

must comply with the following:

- (1) A bend must not impair the serviceability of the pipe.
- (2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage.
- (3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless —
 - (i) The bend is made with an internal bending mandrel; or
 - (ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall thickness ratio less than 70.
- (b) Each circumferential weld of steel pipe which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process.
- (c) Wrought-steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters).
- (d) An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.

[Amdt. 192-26, 41 FR 26016, June 24, 1976; Amdt. 192-29, 42 FR 42865, Aug. 25, 1977 with Amdt. 192-29 Correction, 42 FR 60148, Nov. 25, 1977; Amdt. 192-49, 50 FR 13224, Apr. 3, 1985; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

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

- (a) Hot bends made on cold-worked or heat-treated pipe should be designed in accordance with §192.105(b).
- (b) Cold field bends of high-strength line pipe are prone to forming cosmetic ripples. These ripples can appear more pronounced when viewed on thin-film coated (high gloss) pipe. Although not perfectly smooth, these ripples generally do not impair the serviceability of the pipe. However, the operator should ensure that the bending procedures used will not produce ripples that will impair the serviceability of the pipe. A reference for evaluating whether ripples produced in the bending process have impaired the serviceability is PRCI L51740, "Evaluation of the Structural Integrity of Cold Field-Bent Pipe."

§192.315

Wrinkle bends in steel pipe.

[Effective Date: 07/13/98]

- (a) A wrinkle bend may not be made on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent, or more, of SMYS.
- (b) Each wrinkle bend on steel pipe must comply with the following:
 - (1) The bend must not have any sharp kinks.
 - (2) When measured along the crotch of the bend, the wrinkles must be a distance of at least one pipe diameter.
 - (3) On pipe 16 inches (406 millimeters) or larger in diameter, the bend may not have a deflection of more than 1½ degrees for each wrinkle.

(4) On pipe containing a longitudinal weld the longitudinal seam must be as near as practicable to the neutral axis of the bend.

GUIDE MATERIAL

No guide material necessary.

§192.317

Protection from hazards.

[Effective Date: 07/08/96]

(a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations.

(b) Each aboveground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

(c) Pipelines, including pipe risers, on each platform located offshore or in inland navigable waters must be protected from accidental damage by vessels.

[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]

GUIDE MATERIAL

1 NATURAL HAZARDS (§192.317(a))

- (a) Reasonable precautions (e.g., increasing the wall thickness, constructing revetments, preventing erosion, installing anchors, and providing flexibility) should be taken to protect the transmission line or main.
- (b) Where transmission lines or mains cross areas that are normally under water or subject to flooding (e.g., lakes, bays, swamps, and river crossings), sufficient weight or anchorage should be applied to the line to prevent flotation. This may include areas behind protected levees and areas seaward of floodgates.
- (c) For underwater crossings that may be subject to washout due to the natural hazards of bed changes, high water velocities, deepening of the channel, or changing of the channel location in the bed, attention should be given to designing protection for the transmission line or main. Considerations include the following:
 - (1) The crossing should be located in the more stable bank and bed locations.
 - (2) The depth of the line, location of the bends installed in the banks, and the wall thickness of the pipe should be selected based on the characteristics of the crossing.

Note: Locations where these design considerations apply include five areas identified by the Federal Emergency Management Agency (FEMA) as containing significant pipeline systems that are threatened by flooding (San Jacinto/Houston Ship Channel; Southern Louisiana Area; Ventura

County, CA; Cushing, OK; San Francisco Bay Area).

- (3) Pipe installation using horizontal directional drilling to help place pipelines below elevations of 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 dB μ V 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

This guide material is under review following Amendment 192-132.

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

Addendum 2, February 2023

Addendum 4, May 2024

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

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.
- (d) A means of locating inserted plastic pipe should be provided (see 2.4 and 2.5 above).

3.2 *Special considerations.*

- (a) That portion of the plastic pipe which spans disturbed earth should be protected by bridging, by

compaction of the soil under the plastic pipe, or by other means to prevent the settling of the backfill from shearing the plastic pipe.

- (b) The portion of the plastic pipe exposed due to the removal of a section of casing pipe or abandoned pipeline should have sufficient strength or be protected with bridging or other means, so as to withstand the anticipated external soil loadings.
- (c) Protective sleeve installations that are designed to mitigate the stresses imposed onto the plastic pipe in the transition area should be considered if undue stresses are anticipated, or if recommended by the manufacturer. The installation of protective sleeves, in addition to providing adequate backfill and compaction around the transition area, reduces excessive bending and shear stresses. For protective sleeves, see guide material under 192.367.
- (d) Cased plastic pipe can contract due to cold gas or low ambient temperature. See 3.5(f) of the guide material under §192.281.
- (e) Where a gas leak migrating through the annular space between the plastic pipe and the casing or abandoned pipeline could result in a hazardous condition, consideration should be given to plugging the annular space at one or both ends. Plugs may also be provided at intermediate points, such as where the casing or abandoned pipeline is cut, to permit the installation of a service tee or a lateral main. Care should be used in the selection of the plugging material to avoid damage to the plastic pipe. Both urethane foam and grout have been found to be effective for this purpose.
- (f) If water that has accumulated between the casing or abandoned pipeline and the carrier pipe freezes, the carrier pipe can be constricted (affecting the capacity) or damaged causing a leak. One or more of the following steps can be taken to minimize this possibility.
 - (1) Sizing the pipe so that the formation of ice between the carrier and the casing or abandoned pipeline will not constrict the carrier pipe to the extent that service is affected.
 - (2) Providing for drainage at the lower points in the casing or abandoned pipeline.
 - (3) Inserting a filler, such as a closed cell foam material, in the annular space.

3.3 Reference.

See 8 below for plastic pipe encased on bridges.

4 PROVISIONS FOR BENDS

4.1 General considerations.

The bends should be free of buckles, cracks, or other evidence of damage.

4.2 Bending radius.

Plastic pipe may not be deflected to a radius smaller than the minimum recommended by the manufacturer for the kind, type, grade, wall thickness, and diameter of the particular plastic pipe used.

5 SQUEEZE-OFF AND REOPENING THERMOPLASTIC PIPE FOR PRESSURE CONTROL PURPOSES

5.1 Preliminary investigation.

Before thermoplastic pipe is squeezed-off and reopened, investigations and tests should be made to determine that the particular type, grade, size, and wall thickness of pipe of the same manufacture can be squeezed-off and reopened without causing failure under the conditions which will prevail at the time of the squeeze-off and reopening. References for squeeze-off procedures, tools, and precautions are included in the following.

- (a) AGA XR0603, "Plastic Pipe Manual for Gas Service."
- (b) GRI-92/0147.1, "Users' Guide on Squeeze-Off of Polyethylene Gas Pipes."
- (c) GRI-94/0205, "Guidelines and Technical Reference on Gas Flow Shut-Off in Polyethylene Pipes Using Squeeze Tools."
- (d) ASTM F1041, "Standard Guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing."
- (e) ASTM F1563, "Standard Specification for Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing."

5.2 Field consideration.

- (a) The work should be done using equipment and procedures that have been established and proven by test to be capable of performing the operation safely and effectively.

- (b) If it has been determined by investigation and testing that squeeze-off and reopening affects the long-term properties of the pipe, the squeezed-off and reopened area of the pipe should be reinforced or the pipe segment replaced.
- (c) To prevent squeeze-off at the same point, a permanent mark or clamp should be put on the plastic pipe at the location of the squeeze point.

6 DAMAGE PREVENTION

- (a) For temporary markings, see 4 of the guide material under §192.319.
- (b) For damage prevention considerations while performing directional drilling or using other trenchless technologies, see Guide Material Appendix G-192-6.

7 PLASTIC PIPE TEMPORARILY INSTALLED ABOVE GROUND

7.1 *Aboveground exposure to sunlight.*

Before using plastic pipe above ground, the operator should obtain the recommended maximum exposure time from the manufacturer and determine the date of manufacture from the Pipe Production Code marked on the pipe. If the operator cannot accurately document the actual time that pipe was stored outdoors, the entire time since the date of manufacture should be considered as aboveground exposure.

7.2 *Protection from external forces.*

Means to protect the pipe may include:

- (a) Barricades.
- (b) Fencing.
- (c) Elevation support. To prevent strain on the plastic pipe due to sagging or wind forces, elevation support should be provided. A reference for determining support spacing is PPI Handbook of Polyethylene Pipe, Chapter 8, "Above-Ground Applications for Polyethylene Pipe."
- (d) Signs and markers.
- (e) Physical barriers, such as planks or sleeves.

7.3 *Temperature exposure.*

Aboveground pipe is exposed to greater variations in temperature than pipe installed below ground. During installation, consideration should be given to pipe elongation and contraction as the temperature changes during the day or seasonally.

7.4 *Valves.*

Valves installed in aboveground plastic pipe should be braced or anchored, or the adjacent pipe stiffened or reinforced, to decrease torque forces being transferred to the pipe during operation of the valve.

8 PLASTIC PIPE INSTALLED ON BRIDGES

8.1 *Design considerations.*

The following information for temperature, ultraviolet radiation, external damage, and chemical resistance should be considered when designing plastic pipe systems for installation on bridges.

- (a) Temperature.
 - (1) Ensure that the hydrostatic design basis (HDB) of the plastic material for the highest temperature anticipated is sufficient to meet the design pressure required by §192.121. Consider heavier-wall plastic pipe or a plastic pipe material with a higher HDB at the anticipated use temperature.
 - (2) If the existing HDB is insufficient for the anticipated temperature, consider the potential of both temperature increase and decrease to ensure that the pipeline and joints are adequate for the longitudinal stresses imposed by temperature variations.
 - (3) Where the pipeline is installed in a casing, consider installing the pipe in a manner that minimizes thermal effects of heat transfer from the casing to the pipeline and prevents abrasion of the pipe due to thermal expansion and contraction of the plastic pipe. Methods to minimize thermal forces include the following.

- (i) Installation of spacers. The spacers should be placed sufficiently close together to prevent excessive deflection (sag) between the spacers for anchored and guided pipe. Consideration should be given to significant longitudinal stresses when deflection is minimized. Alternatively, the spacers may be placed at a sufficient distance to allow deflection between the spacers to reduce the longitudinal stress. In either case, the amount of deflection should not allow the pipe to contact the casing between spacers. It may be necessary to consider the thermal conductivity of the spacers if they are metallic.
 - (ii) Filling the annular space between the pipe and its casing with a tight-fitting insulating material.
- (b) Ultraviolet radiation.
Methods to protect plastic pipe from ultraviolet radiation include the following.
- (1) Installation of pipe within a casing.
 - (2) Use of compatible external coating on the pipe.
- (c) External damage.
- (1) Position the pipeline to protect it from external damage. Consider providing additional protection, such as installation in a casing or utility tunnel.
 - (2) Where installed in a casing, the pipeline should be protected from shear forces imposed by soil or other loading at the ends of the casing.
- (d) Chemical resistance.
Consider the installation environment (e.g., salts used on roads during winter, vehicle oils), and ensure that the plastic pipe is adequate for the exposure.

8.2 *Other considerations.*

- (a) Other regulations. The agency having jurisdiction over the bridge should be consulted to determine if there are additional requirements.
- (b) Casing end seals. Consider the installation of casing end seals to prevent water from entering the annular space between a casing and the pipeline.
- (c) Valves. Consider installing valves to isolate the pipe on the bridge in case of a leak or failure.
- (d) Seismic. Consider the effects of abnormal movement in areas of seismic activity.
- (e) Joints. Butt fusion, electrofusion, or ASTM D2513 (see §192.7) Category 1 mechanical fittings should be used. However, Category 2 or Category 3 mechanical fittings may be used provided their joining procedure includes additional restraint as needed to meet the pullout requirements of §192.283(b).

8.3 *References.*

- (a) ASME I00353, "Installation of Plastic Gas Pipeline in Steel Conduits Across Bridges."
- (b) PPI Handbook of Polyethylene Pipe, Chapter 8, "Above-Ground Applications for Polyethylene Pipe."

9 INSTALLATION OF PA-11 or PA-12 PIPING FOR HIGHER PRESSURE APPLICATIONS

If PA-11 or PA-12 piping is installed for operating pressures up to and including 125 psig, standard installation procedures may be used. If pressures exceed 125 psig, the following guidance should be considered.

9.1 *Installation.*

In addition to a method of locating (see 2.4 above), consider using a highly visible yellow warning tape (see 2.5 above) with a legend, such as "WARNING: Buried High Pressure Plastic Gas Pipeline."

9.2 *Pressure tests.*

Safety precautions similar to those used during other higher pressure pipeline tests should be employed

due to the higher operating and test pressures for PA-11 or PA-12 piping. For example, PA-11 pipelines with an intended MAOP of 200 psig are required to be tested at 300 psig per §192.619(a)(2)(i).

9.3 Hot taps.

Currently, only mechanical or electrofusion hot-tapping tees are recommended for use on PA-11 or PA-12 piping. To avoid a blow-out when making hot taps using fusion fittings, the pressurized pipeline should not be heated above the manufacturer's recommendations. Consult the manufacturer for the appropriate hot-tapping joining method recommendations. See 3 of the guide material under §192.123.

§192.323

Casing.

[Effective Date: 11/12/70]

Each casing used on a transmission line or main under a railroad or highway must comply with the following:

- (a) The casing must be designed to withstand the superimposed loads.
- (b) If there is a possibility of water entering the casing, the ends must be sealed.
- (c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.
- (d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.

GUIDE MATERIAL

- (a) Where plastic piping must be cased or bridged, suitable precautions should be taken to prevent crushing or shearing the piping. See guide material under §192.321.
- (b) A reference for the design, installation, maintenance, repair, and monitoring of steel-cased pipelines is NACE SP0200, "Steel-Cased Pipeline Practice."

§192.325

Underground clearance.

[Effective Date: 07/13/98]

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

(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

(c) In addition to meeting the requirements of paragraph (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.

(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in §192.175(b).

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

GUIDE MATERIAL

1 CLEARANCE

1.1 *Transmission lines (§192.325(a)).*

If a minimum of 12 inches of clearance cannot be attained at the time of installation, less clearance may be allowed provided:

- (a) Adequate measures are undertaken to prevent contact between the pipeline and the underground structure, such as encasement of the pipeline with concrete, polyethylene or vulcanized elastomer, or the installation of sand-cement bags, concrete pads or open-cell polyurethane pads in the space between the pipeline and the underground structure.
- (b) Adequate measures are taken to prevent mechanical damage to the pipe and coating of multiple pipeline bundles installed by directional boring. Adequate measures should be employed to provide separation between the individual pipelines in the bundle in order to minimize damage to the pipe and coating. This may be accomplished by employing dielectric spacing devices (e.g., dense rubber spacers) or vulcanized elastomer spacers between the individual pipelines in the bundle. See §192.461(e).

1.2 *Mains (§192.325(b)).*

The following possible activities should be considered when determining the clearance to be attained between the main being installed and other underground structures.

- (a) Installation and operation of maintenance and emergency control devices, such as leak clamps, pressure control fittings, and squeeze-off equipment.
- (b) Connection of service laterals to both the main and other underground structures.
- (c) For additional methods of protection in lieu of sufficient clearance, see 1.1(a) above.

1.3 *Clearance between plastic main or transmission line and any source of heat (§192.325(c)).*

The operator should consider the degree of the hazard presented by the heat source when determining the clearance, insulation, or protective material. For installations near electric or steam lines, the operator should also consider the following.

- (a) A minimum radial separation of 12 inches is recommended by the Common Ground Alliance's "Best Practices" Guide, Practice Statement 2.12, available at <https://commongroundalliance.com/best-practices-guide>. See 5.3(d) of the guide material under §192.361.
- (b) For installations near electric lines, see 5.3(e) of the guide material under §192.361.

2 ADJACENT UNDERGROUND STRUCTURES

When installing new mains or replacing existing mains, the proximity and condition of existing conduits, ducts, sewer lines, and similar structures, including abandoned structures, should be considered since they have the potential to provide a path for the migration of leaking gas.

§192.327

Cover.

[Effective Date: 09/09/04]

(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:

Location	Normal soil Inches (Millimeters)	Consolidated rock Inches (Millimeters)
Class 1 locations	30 (762)	18 (457)
Class 2,3, and 4 locations	36 (914)	24 (610)
Drainage ditches of public roads and railroad crossings	36 (914)	24 (610)

(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.

(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.

(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality —

- (1) Establishes a minimum cover of less than 24 inches (610 millimeters);
- (2) Requires that mains be installed in a common trench with other utility lines; and
- (3) Provides adequately for prevention of damage to the pipe by external forces.

(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).

(f) All pipe installed offshore, except in the Gulf of Mexico and its inlets, under water not more than 200 feet (60 meters) deep, as measured from the mean low tide, must be installed as follows:

(1) Except as provided in paragraph (c) of this section, pipe under water less than 12 feet (3.66 meters) deep, must be installed with a minimum cover of 36 inches (914 millimeters) in soil or 18 inches (457 millimeters) in consolidated rock between the top of the pipe and the natural bottom.

(2) Pipe under water at least 12 feet (3.66 meters) deep 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.

(g) All pipelines installed under water in the Gulf of Mexico and its inlets, as defined in §192.3, must be installed in accordance with §192.612(b)(3).

[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. 192-98, 69 FR 48400, Aug. 10, 2004]

GUIDE MATERIAL

See Guide Material Appendix G-192-13.

§192.328

**Additional construction requirements for steel pipe using
alternative maximum allowable operating pressure.**

[Effective Date: 12/22/08]

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure calculated under §192.620, a segment must meet the following additional construction requirements. Records must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this construction issue:	The pipeline segment must meet this additional requirement:
(a) Quality assurance	<p>(1) The construction of the pipeline segment must be done under a quality assurance plan addressing pipe inspection, hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing.</p> <p>(2) The quality assurance plan for applying and testing field applied coating to girth welds must be:</p> <ul style="list-style-type: none"> (i) Equivalent to that required under §192.112(f)(3) for pipe; and (ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating application.
(b) Girth welds	(1) All girth welds on a new pipeline segment must be non-destructively examined in accordance with §192.243(b) and (c).
(c) Depth of cover	<p>(1) Notwithstanding any lesser depth of cover otherwise allowed in §192.327, there must be at least 36 inches (914 millimeters) of cover or equivalent means to protect the pipeline from outside force damage.</p> <p>(2) In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.</p>
(d) Initial strength testing	(1) The pipeline segment must not have experienced failures indicative of systemic material defects during strength testing, including initial hydrostatic testing. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipe is in service at least 60 days prior to operating at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
(e) Interference currents	(1) For a new pipeline segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.

[Issued by RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008]

Guide Material

1 GENERAL REQUIREMENTS

- (a) If a new or existing steel pipeline meets the additional construction requirements of §192.328, it may be eligible for operation at an alternative maximum allowable operating pressure (MAOP) as determined under §192.620.
- (b) A greater level of quality assurance is required for additional construction requirements if an alternative MAOP is to be permitted (§192.328(a)). Each additional construction requirement should be addressed in a quality assurance plan.

2 QUALITY ASSURANCE

- (a) For this guide material, quality assurance is an overall process to ensure and document that the pipeline construction elements identified in §192.328(a)(1) are done in a manner that will not compromise future integrity.
- (b) Quality assurance for pipeline construction might consist of the following core elements.
 - (1) Identifying the needed processes, which must include those elements listed in §192.328(a)(1).
 - (2) Determining the process sequence and interaction.
 - (3) Determining the criteria which will be measured or tracked and a methodology that will be used to ensure that process acceptance is within tolerance limits.
 - (4) Identifying the necessary resources for the operation and monitoring of the processes, including a skill and knowledge assessment for the personnel.
 - (5) Monitoring, measuring, and analyzing processes during pipeline construction and reviewing the effectiveness of those processes.
 - (6) Implementing actions to achieve required project results and to have continuing improvement in the individual processes.
 - (7) Identifying and maintaining records and support documentation that should be retained. These records might be part of the ongoing evaluations in the operator's Integrity Management Program or be associated with the conditions of a special permit (waiver) required by PHMSA-OPS under §190.341(d)(2).
Note: A "special permit" was previously referred to as a "waiver" by PHMSA-OPS. State terminology may differ (e.g., wavier, variance).
- (c) Quality assurance processes can use new procedures or existing procedures as modified, and should be measurable to determine performance.

3 FIELD-APPLIED COATINGS

3.1 General.

Fusion-bonded, two-part epoxy coatings, or three-layer coatings may be used to coat girth welds during the construction of new transmission pipelines with an alternative MAOP. Coating defects with these field-applied coatings may be caused by the following.

- (a) Failing to follow manufacturer's instructions or operator's procedures.
- (b) Improper cleaning (e.g., coating over mud, debris, condensation, rust).
- (c) Inadequate surface preparation.
- (d) Abrasive blast technique – lack of correct bevel or no overlap at factory coating.
- (e) Inadequate mixing of the epoxy.
- (f) Application temperature too hot or cold.
- (g) Heat damage to the factory fusion bonded epoxy (FBE) coating.
- (h) Water in the pipe during heating, which prevents uniform heating.
- (i) Coating in high wind with blowing dirt.
- (j) Girth weld coating not fully bonded to pipe.
- (k) Inadequate skills or technique.

3.2 *Pipe surface preparation standards.*

Pipe surface preparation is required to get the needed pipe surface profile for a field-applied coating. This includes abrasive blasting, achieving the required coating cutback, and, if required, pre-heating the girth weld area to get the required surface temperature in accordance with the coating manufacturer's specifications. In addition to the manufacturer's installation instructions, standards from the following organizations may be used as guidelines for preparing the pipe surface for field-applied coatings.

- (a) The Society for Protective Coatings (SSPC).
- (b) National Association of Corrosion Engineers (NACE).

3.3 *Application method.*

- (a) Spray.
- (b) Brush.
- (c) Roller.

3.4 *Environmental considerations.*

- (a) Air and pipe surface temperatures.
- (b) Relative humidity and dew point.
- (c) Presence of precipitation or condensation.
- (d) Other factors, such as wind.

3.5 *Coating application considerations.*

- (a) Adherence to coating thickness requirements and verification measurements.
- (b) Minimum cure times for liquid and dry powder applications.
- (c) Adherence to manufacturers' application instructions, especially with liquid coatings.
- (d) Visual coating inspection before lowering pipe into ditch to identify the following.
 - (1) Runs.
 - (2) Drips.
 - (3) Blisters.
 - (4) Foreign inclusions.
 - (5) Insufficient overlap on tape and shrink sleeve applications.
 - (6) Insufficient dry-film thickness.

4 COATING INSPECTION AND HOLIDAY TESTING

Prior to backfilling, the coating of the entire pipeline should be visually inspected by trained inspectors. This visual examination might be supported with the use of a holiday detector (jeep) to detect coating anomalies or imperfections. Coating integrity could be compromised if the following procedural errors occur when jeeping.

- (a) Failing to adequately clean the pipe before jeeping.
- (b) Using personnel and inspectors without adequate training.
- (c) Failing to follow manufacturer's instructions for holiday detector.
- (d) Using a detector that was not calibrated per manufacturer's specifications.
- (e) Using damaged (bent) or dirty detector springs.
- (f) Using incorrect voltage setting on detector.
- (g) Jeeping too fast.
- (h) Jeeping with high resistance in electrical circuit.
- (i) Jeeping over debris (e.g., tape, fiberboard) stuck to the pipe.
- (j) Jeeping over coating repairs before they are dry.

5 NONDESTRUCTIVE TESTING OF GIRTH WELDS

- (a) All girth welds of a new pipe segment operating at an alternative MAOP must be nondestructively tested (§192.328(b)).
- (b) Defects at girth welds could be caused by the following procedural errors during the welding process.

- (1) Incorrect welding procedure used.
 - (2) Incomplete weld procedure qualification.
 - (3) Lack of inspector oversight.
 - (4) Improper joint fit-up.
 - (5) High-low pipe alignment issues.
 - (6) Improper storage of low hydrogen rods.
 - (7) Improper welding electrode selection.
 - (8) Incorrect pre-heat or interpass temperature.
 - (9) Premature alignment clamp release.
 - (10) Arc burns due to poor welding practices.
 - (11) Inadequate visual weld inspection.
 - (12) Improper diffusion of hydrogen during welding process.
 - (13) Rapid cooling of weld.
- (c) For additional guidance, see guide material under §§192.243 and 192.620.

6 DEPTH OF COVER

- (a) A minimum depth of 36 inches or equivalent means to protect the pipeline from outside force damage is required for pipeline segments operating at an alternative MAOP (§192.328(c)).
- (b) For additional guidance on depth of cover and equivalent means to provide protection from outside forces, see Guide Material Appendix G-192-13.
- (c) Depth of cover should be noted in construction records.

7 INITIAL STRENGTH TESTING

- (a) A root-cause analysis is required for any initial strength testing failure on a pipeline that is being constructed to operate at an alternative MAOP to determine whether systemic material defects are present (§192.328(d)).
- (b) A root-cause analysis could have the following core elements.
 - (1) Definition and scope of material issue.
 - (2) Data gathering.
 - (3) Threat assessments.
 - (4) Supporting investigations.
 - (5) Root-cause determination.
 - (6) Recommendations and their implementation.
 - (7) Monitoring.
- (c) For additional guidance on strength testing, see guide material under §§192.503, 192.505, and 192.620, and Guide Material Appendix G-192-9.

8 INTERFERENCE CURRENTS

See guide material under §§192.455 and 192.473.

9 RECORDS

- (a) Records demonstrating compliance with the additional construction requirements for an alternative MAOP must be maintained for the useful life of the pipeline (§192.328). These records might include the following.
 - (1) Material specifications.
 - (2) Construction specifications.
 - (3) Welding specifications and procedures.
 - (4) Bills of lading or shipping manifests.
 - (5) Daily construction inspection reports and documentation.
 - (6) Photographs of construction activities.

- (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.

- (d) When selecting a meter or service regulator location, consideration should be given to the potential damage by outside forces, such as those from vehicles, construction equipment, tools, materials that might be placed on the meter, and falling objects (e.g., packed snow or ice from a roof). Where such potential is evident, the meter or service regulator should be protected or an alternate location selected. See 2 below and Guide Material Appendix G-192-13.
- (e) Meters and service regulators should not be installed in contact with the soil or other potentially corrosive materials. The potential for shorting out the insulating fitting should also be considered.
- (f) See guide material under §192.479 for the following relative to atmospheric corrosion.
 - (1) General considerations.
 - (2) Specific considerations regarding the meter and service regulator location and the regulator vent lines and tubing.
- (g) Section 192.353(a) requires that each meter and service regulator be installed in a readily accessible location. Each location should accommodate access for reading, inspection, repairs, testing, changing, and operation of the gas shut-off valve.
- (h) The meter location should normally permit the installation of the service line in a straight line perpendicular to the main.
- (i) Meters and service regulators should not be installed in the following locations.
 - (1) Under or in front of windows or other building openings which may be used as emergency fire exits or under interior or exterior stairways.
 - (2) A crawl space with limited clearance.
 - (3) Near building air intakes.

2 OUTSIDE METER OR SERVICE REGULATOR LOCATIONS

- (a) Outside meters or service regulators should be installed in the following locations.
 - (1) Preferably, above ground in a protected location, adjacent to the building served.
 - (2) In a properly designed buried vault or meter box.
 - (i) The vault or meter box should be located on the customer's property, either adjacent to the building served or near the gas main.
 - (ii) Vaults may be located in a public right-of-way. Consent of local jurisdictions may be required.
 - (iii) Proper design and location considerations should include ventilation, vehicular traffic (see §192.355(c)), potential for soil accumulation, surface water runoff, high water table, and proximity to building air intakes or openings.
 - (iv) Piping installed through vault walls should be properly coated to protect from corrosion.
 - (v) Note §192.189(b) that states:
 - A vault containing gas piping may not be connected by means of a drain connection to any other underground structure.**
 - (vi) When outside a paved surface, consideration should be given to the potential for fill, topsoil, or sod being placed over the vault.
 - (vii) See guide material under §192.355 for considerations involving service regulator and relief vents in vaults.
- (b) At locations where vehicular damage is reasonably anticipated, some means of providing protection to the meter set assembly include the following.
 - (1) Distance from roadways or driveways.
 - (2) Installation of posts, parking bumpers, or barricades.
 - (3) Location behind existing protective structures.
 - (4) Installation in a buried vault or meter box.

3 INSIDE METER OR SERVICE REGULATOR LOCATIONS

- (a) Inside meter locations should be considered under the following conditions.
 - (1) An acceptable outside location is not available or practical.
 - (2) Protection from ambient temperatures is necessary to avoid meter freeze-ups. (This condition is most often encountered in low-pressure systems that pick up moisture from water-sealed gas holders or other sources.)
- (b) Where practical, meters and service regulators should not be located in confined engine, boiler, heater, or electrical equipment rooms, nor should they be located in living quarters, closets, restrooms, bathrooms, or similar locations.
- (c) Each service regulator installed within a building should be located as near as practical to the service line entry point. When selecting the service regulator location, venting requirements and the vent piping location and length should be considered. See §§192.355 and 192.357.
- (d) Where a meter or service regulator is located inside a building, §192.365 requires a readily accessible shut-off valve that, if feasible, is located outside the building.
- (e) Meters and service regulators in certain inside locations (e.g., parking garages) may require protection from vehicular damage. See 2(b) above.
- (f) For additional considerations regarding plastic service lines, see guide material under §192.375.

4 OTHER METER OR SERVICE REGULATOR LOCATIONS

An alternate consideration is a specially constructed cabinet recessed in the building wall, sealed from inside the building and vented to and accessible from outside the building.

§192.355

Customer meters and regulators: Protection from damage.

[Effective Date: 02/22/88]

- (a) **Protection from vacuum or back pressure.** If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system.
- (b) **Service regulator vents and relief vents.** Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must —
 - (1) Be rain and insect resistant;
 - (2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and
 - (3) Be protected from damage caused by submergence in areas where flooding may occur.
- (c) **Pits and vaults.** Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated must be able to support that traffic.

[Amdt. 192-58, 53 FR 1633, Jan. 21, 1988]

GUIDE MATERIAL

1 PROTECTIVE DEVICE

A suitable protective device should be installed downstream of the meter and regulator under the following conditions.

- (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.

2 COATED STEEL SERVICE LINES IN BORES

2.1 General.

When coated steel pipe is to be installed in a bore, care should be taken to prevent damage to the coating during installation.

2.2 Boring or driving.

- (a) When a coated steel pipeline is to be installed by boring or driving, the pipe should not be used as the bore pipe or drive pipe unless the coating is sufficiently durable to withstand the operation. If considering retaining the bored or driven pipe as the carrier pipe, it should be demonstrable that the coating is sufficiently durable for the anticipated soil conditions and installation forces. Where significant damage to the coating may result from boring or driving, the coated pipeline should be installed in an oversize bore or in casing pipe of sufficient diameter to accommodate the pipe.
- (b) See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies.
- (c) See Guide Material Appendices G-192-15A and G-192-15B for additional considerations for horizontal directional drilling to install steel pipelines and plastic pipelines, respectively.

2.3 Special consideration.

In exceptionally rocky soil, and if significant damage to the coating is likely, coated pipe should not be inserted through an open bore.

3 PLASTIC SERVICE LINES

3.1 Main connection.

The excavation below the piping at the main connection should be tamped using compactable material. Where non-compactable material is present, such as very wet mud, it may be necessary to replace it with compactable material.

The connection between a PE service line and the main is particularly susceptible to excessive shear stresses due to the design of the joint. Consideration should be made in the joint design to determine if a protective sleeve is necessary, in addition to providing adequate backfill and compaction around the transition area, to reduce excessive bending and shear stresses. Protective sleeves that are designed to mitigate the stresses imposed onto the plastic pipe in the transition areas should be considered if undue stresses at this joint are anticipated, or if recommended by the manufacturer. For protective sleeves, see guide material under §192.367. For guide material specific to protective bridging sleeves, see Figures 192.361A and 192.361B.

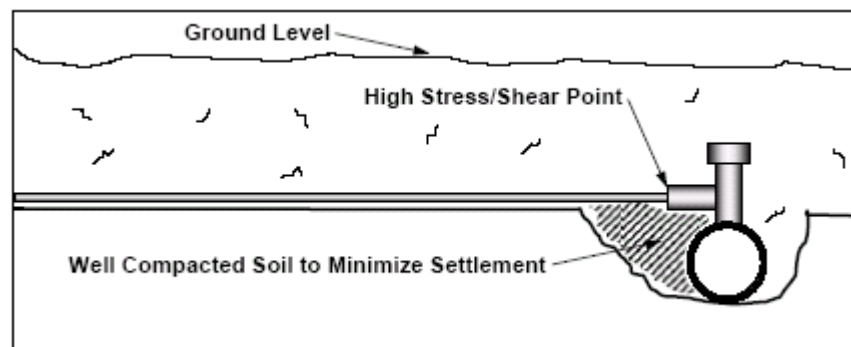


FIGURE 192.361A
Tapping Tee Installation with Compaction of Soil

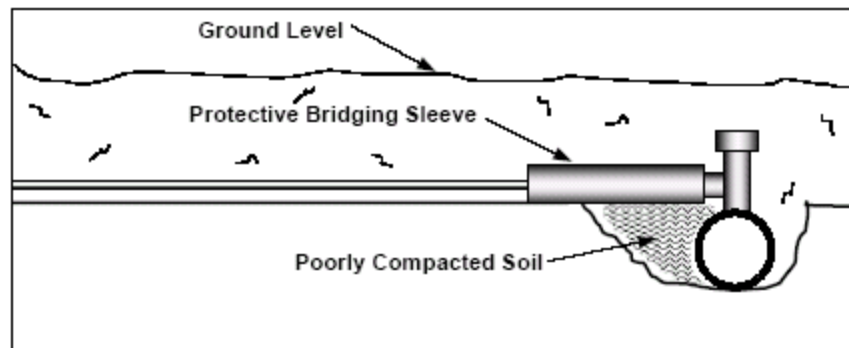


FIGURE 192.361B
Tapping Tee Installation Using Protective Bridging Sleeve
Across Poorly Compacted Soil

3.2 Building wall or meter set assembly.

The transition from plastic pipe to more rigid piping should be protected from shear and bending as at the main connection. The considerations in 3.1 above should be applied to joints in PE piping in the transition area to the meter riser and the through-the-wall fitting at the building wall or meter set assembly. If there is neither a basement excavation nor a footing excavation, the trench bottom should be compacted and smoothed.

If there is either a basement excavation or a footing excavation, compaction may not be feasible because of possible damage to the building wall. Where compaction is not feasible, some other method of continuous support for the service line should be provided over the disturbed soil.

3.3 Boring.

See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies.

3.4 Locating underground service lines.

See 2.4 of the guide material under §192.321 for providing a means of locating nonmetallic service lines.

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 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.

5 ADJACENT UNDERGROUND STRUCTURES

5.1 Existing structures.

When installing a new service line or replacing an existing service line, the proximity and condition of existing conduits, ducts, sewer lines and similar structures, including abandoned structures, should be considered since they have the potential to provide a path for the migration of leaking gas.

5.2 Trees and shrubs.

Consideration should be given to not installing service lines in close proximity to specific types of trees or shrubs which have extensive root growth, particularly the younger ones. Such growth could exert forces on the pipe and nearby joints.

5.3 Underground clearance and heat sources.

(a) Each gas service line should be installed with sufficient clearance from, or insulated from, any

known heat source (e.g., an underground electric or steam line), which could impair the serviceability of the gas service line.

- (b) The operator should consider the degree of the hazard presented by the heat source when determining the clearance, insulation, or protective material.
- (c) If possible, the operator should install the gas service line with sufficient clearance from adjacent facilities in order to access it for any necessary repairs or inspections.
- (d) The Common Ground Alliance's "Best Practices" Guide includes Practice Statement 2.12 titled "Supply Line Separation" and is available at <https://commongroundalliance.com/best-practices-guide>. Practice Statement 2.12 recommends a minimum of 12-inch radial separation between supply facilities, such as steam lines, plastic gas lines, other fuel lines, and direct buried electrical supply lines, when installing new direct buried supply facilities in a common trench. If 12-inch separation cannot be feasibly attained at the time of installation, the Practice Statement recommends taking mitigating measures, including the use of insulators, casing, abrasion protection material (e.g., rock shield), or spacers.
- (e) Some low-voltage and high-voltage electric lines may increase the average annual ground temperature of the earth near plastic gas service lines. In such cases, the temperature profile should be established based on the construction, material, and operating conditions. For information on the impact of average annual and maximum ground temperatures and how and when to obtain a temperature profile, refer to "Effect of Elevated Ground Temperature (from Electric Cables) on the Pressure Rating of PE Pipe in Gas Piping Applications," AGA Operations Conference, April 2007, available at www.aga/gptc. The effect of this increased average annual ground temperature is a possible decrease in the pressure rating of plastic pipe. This can be determined by contacting the plastic pipe manufacturer for pressure rating data to determine the LTHS (HDB) at this increased average annual ground temperature using the temperature interpolation method described in PPI TR-3 (see listing in §192.7, not IBR for §192.361). Also, see 4 of the guide material under §192.121.

6 DAMAGE PREVENTION

- (a) For temporary markings, see 4 of the guide material under §192.319.
- (b) For damage prevention considerations while performing directional drilling or using other trenchless technologies, see Guide Material Appendix G-192-6.

7 INSTALLATION OF SERVICE LINES UNDER BUILDINGS

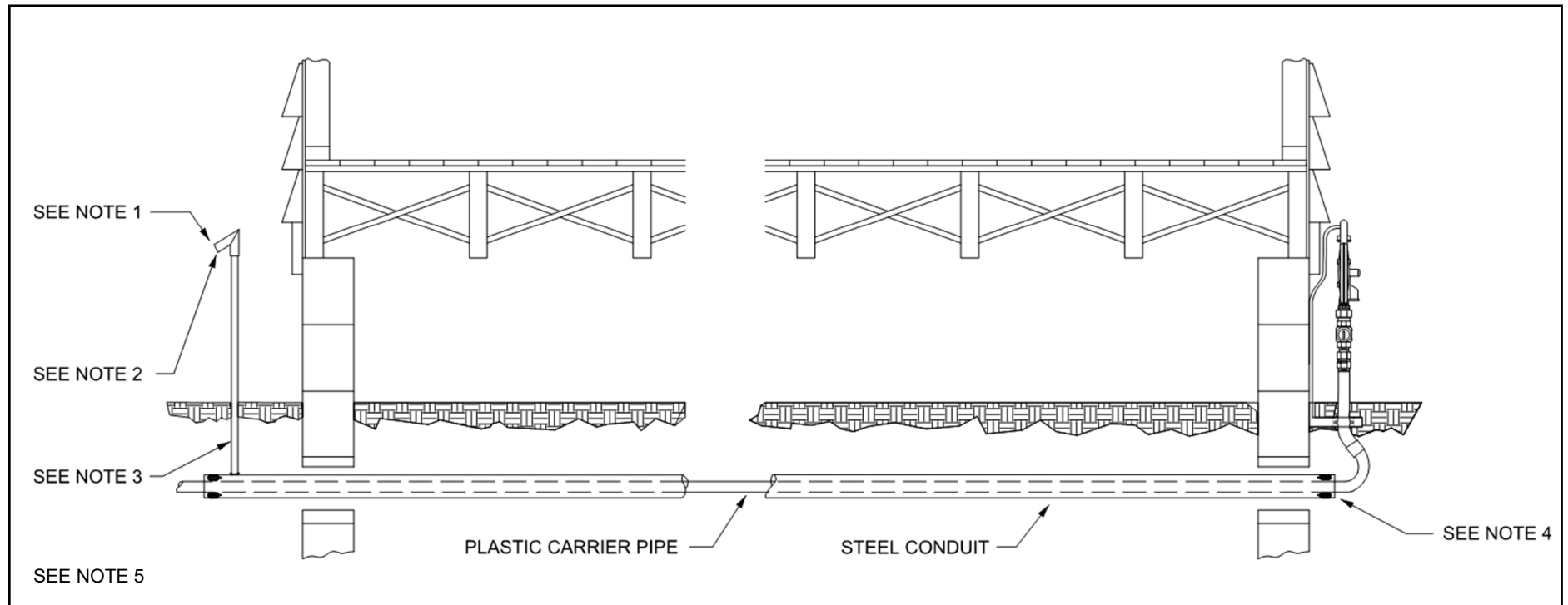
Operators should explore design alternatives to installing an underground service line under a building (e.g., routing the service line piping around the outside of the building). Where unavoidable, the operator should consider the following.

- (a) The conduit (casing) material should be metallic or plastic. Using former service line piping that is already under a building as a conduit should be avoided unless a test confirms that the piping does not have any leakage.
- (b) Installation of a plastic service line in a plastic conduit is an option that could be used to minimize the possibility of corrosion.
- (c) If a metallic service line is to be installed in a metallic conduit, features should be incorporated to prevent contact between the two concentric pipes. An appropriate protective coating should be selected and applied to the metallic service line piping. Electrical isolation should be confirmed.
- (d) Conduit should be at least two nominal pipe sizes larger than the service line pipe to ease insertion of the service line pipe and to aid in future pipe replacement.
- (e) An appropriate material and method should be selected to seal the ends of the conduit (casing) between the conduit and service line. Options include the following.
 - (1) High-expansion foam.
 - (2) Linked-rubber expandable seals.
 - (3) Solid-rubber bushing plugs.
 - (4) Compression couplings or service-head adapters.

(f) For sealed conduits, the vent line to an outdoor location should extend to where leaking gas can escape freely to the atmosphere and away from ignition sources and openings into the building.

(g) Although the conduit is not a pressurized, gas-carrying component, applying a protective coating and cathodic protection to a metallic conduit could be beneficial.

(h) See Figures 192.361C and 192.361D below for installation suggestions.



Note 1 Approved vent with insect screen.

Note 2 Vent outlet should be high enough to avoid inundation by flooding or burial by snow. Use of bollards or similar device should be considered to protect against vehicle damage.

Note 3 Vent pipe at low end of casing to be connected to side or bottom of conduit.

Note 4 Seal conduit with rubberized sealing device or other method.

Note 5 Install cathodic protection and trace wire according to operator's standard.

FIGURE 192.361C

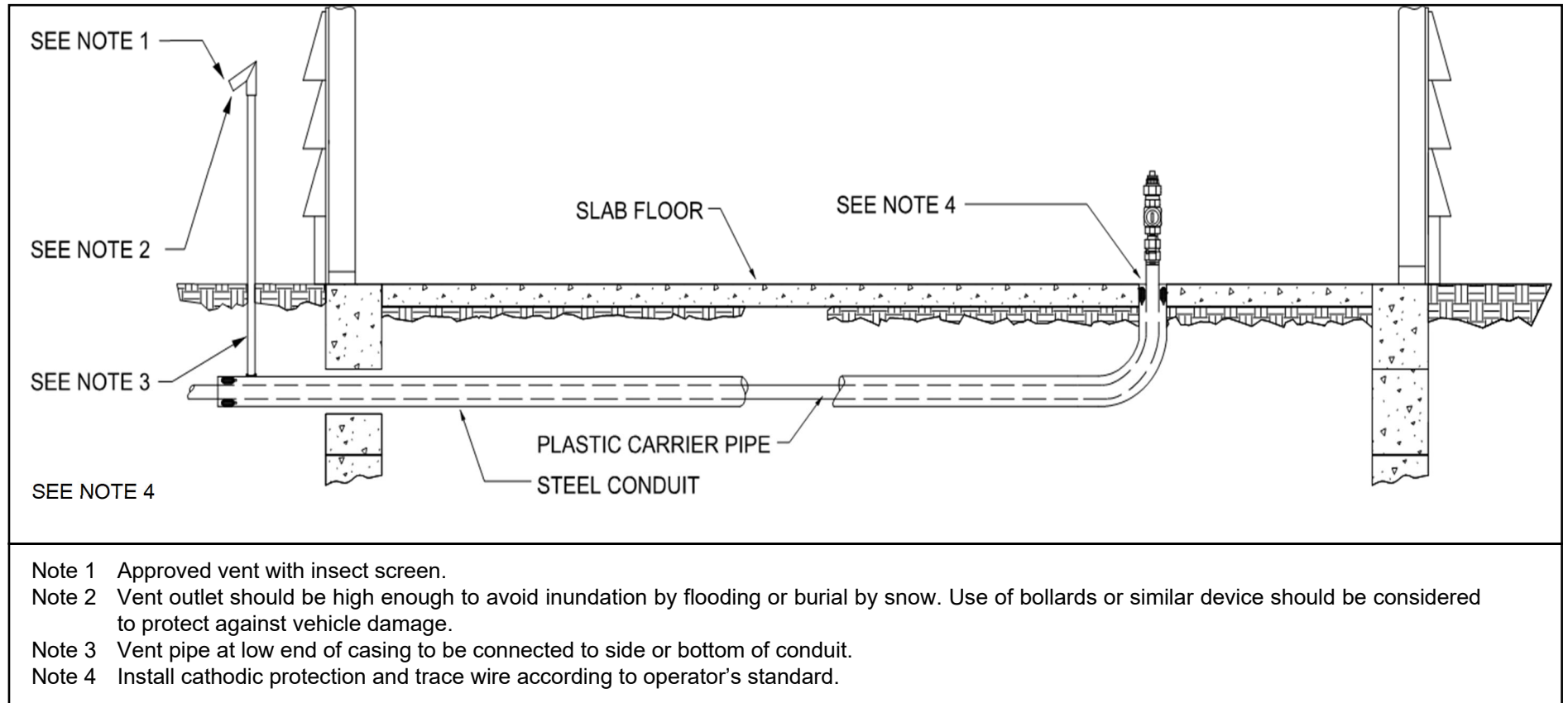


FIGURE 192.361D

8 OTHER CONSIDERATIONS

- (a) For threaded metallic connections, see guide material under §192.273.
- (b) For mechanical joints in plastic pipe, see 3.5 of the guide material under §192.281.
- (c) For main connections, see §192.367.
- (d) For placing warning tape over a service line in a ditch, see 3.5 of the guide material under §192.319.

§192.363

Service lines: Valve requirements.

[Effective Date: 11/12/70]

- (a) Each service line must have a service-line valve that meets the applicable requirements of Subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service line valve.
- (b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.
- (c) Each service-line valve on a high-pressure service line, installed above ground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

GUIDE MATERIAL

- (a) The operator should make certain that the types of service-line valves installed on high-pressure service-lines are suitable. This may be accomplished by making tests or by reviewing the tests made by the manufacturer.
- (b) For excess flow valve (EFV) requirements and considerations, see §§192.381 and 192.383.

§192.365

Service lines: Location of valves.

[Effective Date: 11/12/70]

- (a) *Relation to regulator or meter.* Each service line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.
- (b) *Outside valves.* Each service line must have a shut-off valve in a readily accessible location that, if feasible, is outside of the building.
- (c) *Underground valves.* Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.

GUIDE MATERIAL

When installing a shut-off valve, the operator should consider the access to and operability of the valve under all reasonably anticipated conditions including areas prone to high water or flooding conditions.

§192.367

Service lines: General requirements for connections to main piping.

[Effective Date: 01/22/19]

- (a) *Location.* Each service line connection to a main must be located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.
- (b) *Compression-type connection to main.* Each compression-type service line to main connection must—

- (1) Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading;
- (2) If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system; and
- (3) If used on pipelines comprised of plastic, be a Category 1 connection as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

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

1 MAIN CONNECTION AND PE PIPING

1.1 General.

The connection between a PE service line and the service tee at the main is particularly susceptible to excessive bending and shear stresses due to the design of the joint.

1.2 Backfill and compaction.

It is important that adequate backfill and compaction be provided in the transition area to reduce the stresses at the joint between the service tee and the plastic piping. Protective sleeves or bridging should also be considered if undue stresses are anticipated at these joints.

1.3 Protective sleeves.

(a) Purpose.

Protective sleeves mitigate excessive bending and shear stresses imposed on the plastic pipe at transition areas. Protective sleeve installations are in addition to providing adequate backfill and compaction around transition areas.

(b) Design.

- (1) The protective sleeve should be designed to fully support the PE pipe in the joint area at the service tee.
- (2) The protective sleeve should be of adequate length and inside diameter to ensure that the manufacturer's minimum bend radius is not exceeded.
- (3) The annulus between both the protective sleeve and the service tee, and the PE service line, should be of such fit to avoid overstressing the joint due to anticipated earth settlement after installation.
- (4) Protective sleeves, supplied by several manufacturers, are typically lengths of either PE or PVC pipe.

1.4 Bending at joints in PE piping.

Due to the nature of installation, the service tee connection can experience excessive bending forces that are transmitted to the piping at the service tee joint.

- (a) Bending of PE piping can overstress the joints, which can lead to premature failures. These concerns are heightened when making mechanical joints from steel service tees to PE pipe as the transition is from a rigid steel coupling to a flexible pipe, concentrating stresses at the transition area.

- (b) The minimum bend radii recommendations from various PE piping manufacturers range from 90 to 125 pipe diameters depending on the PE used.

Example: NPS 1 (1.315" nominal outside diameter) PE piping containing a fitting in a bend should be bent at a bend radius no tighter than 118" to 164" depending on the specific pipe manufacturer's recommendation. (Where, 1.315" x 90 = 118"; 1.315" x 125 = 164".) Contact the piping manufacturer

for specific minimum bend radius recommendations.

1.5 *Other considerations.*

See guide material under §192.361.

2 MAIN CONNECTION AND PA-11 or PA-12 PIPING

See 9 of the guide material under §192.321.

§192.369

Service lines: Connections to cast iron or ductile iron mains.

[Effective Date: 11/12/70]

(a) Each service line connected to a cast iron or ductile iron main must be connected by a mechanical clamp, by drilling and tapping the main, or by another method meeting the requirements of §192.273.

(b) If a threaded tap is being inserted, the requirements of §§192.151(b) and (c) must also be met.

GUIDE MATERIAL

See Guide Material Appendix G-192-18.

§192.371

Service lines: Steel.

[Effective Date: 07/13/98]

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

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

GUIDE MATERIAL

No guide material necessary.

§192.373

Service lines: Cast iron and ductile iron.

[Effective Date: 07/13/98]

(a) Cast or ductile iron pipe less than 6 inches (152 millimeters) in diameter may not be installed for service lines.

(b) If cast iron pipe or ductile iron pipe is installed for use as a service line, the part of the service line which extends through the building wall must be of steel pipe.

- (c) **A cast iron or ductile iron service line may not be installed in unstable soil or under a building.**

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

GUIDE MATERIAL

No guide material necessary.

§192.375

Service lines: Plastic.

[Effective Date: 01/22/19]

- (a) Each plastic service line outside a building must be installed below ground level, except that —
- (1) It may be installed in accordance with §192.321(g); and
 - (2) It may terminate above ground level and outside the building, if —
 - (i) The above ground level part of the plastic service line is protected against deterioration and external damage;
 - (ii) The plastic service line is not used to support external loads; and
 - (iii) The riser portion of the service line meets the design requirements of § 192.204.
- (b) Each plastic service line inside a building must be protected against external damage.

[Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

- (a) One method of protecting that part of a plastic service line that is above ground or within a building from external damage is to completely enclose it in a metal pipe of sufficient strength. The metal pipe should have adequate protection against corrosion and should extend a minimum of 6 inches below grade for outside installations.
- (b) For temperature limitations, see §192.121.
- (c) For the installation of PA-11 or PA-12 piping for higher pressure application, see 9 of the guide material under §192.321.
- (d) Plastic pipe may be temporarily installed above ground. For limitations and considerations on such use, see §192.321(g).
- (e) For additional considerations relating to meter or service regulator locations, see guide material under §192.353.

§192.376

Installation of plastic service lines by trenchless excavation.

[Effective Date: 01/22/19]

Plastic service lines installed by trenchless excavation must comply with the following:

(a) Each operator shall take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and 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

- (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.

§192.377

Service lines: Copper.

[Effective Date: 11/12/70]

Each copper service line installed within a building must be protected against external damage.

GUIDE MATERIAL

1 LOCATIONS

1.1 Concealed.

- (a) Except when passing through walls and partitions, concealed locations should be avoided.
- (b) When concealed locations are unavoidable, the service line should be located in hollow partitions rather than solid ones. The piping should be protected from physical damage by tools and other materials penetrating the wall or partition.

1.2 Exposed.

Consideration should be given to appropriate guards and additional supports when an exposed service line may reasonably be expected to be subject to physical damage due to normal activities in its vicinity.

2 SUPPORT

A horizontal run of service line should be supported to resist buckling or bending. The recommended maximum support spacing for commonly used tubing sizes is contained in Table 192.377i.

RECOMMENDED MAXIMUM SUPPORT SPACING	
Tube Size (OD inches)	Support Spacing (feet)
1/2	4
5/8 or 3/4	6
7/8 or 1 1/8	8

TABLE 192.377i

§192.379

New service lines not in use.

[Effective Date: 11/03/72]

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas;

(a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

[Issued by Amdt. 192-8, 37 FR 20694, Oct. 3, 1972]

GUIDE MATERIAL

No guide material necessary.

§192.381

Service lines: Excess flow valve performance standards.

[Effective Date: 04/14/17]

(a) Excess flow valves (EFVs) to be used on service lines that operate continuously throughout the year at a pressure not less than 10 p.s.i. (69 kPa) gage must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer's written specification, to ensure that each valve will:

(1) Function properly up to the maximum operating pressure at which the valve is rated;

(2) Function properly at all temperatures reasonably expected in the operating environment of the service line;

(3) At 10 p.s.i. (69 kPa) gage;

(i) Close at, or not more than 50 percent above, the rated closure flow rate specified by the manufacturer; and

(ii) Upon closure, reduce gas flow —

(A) For an excess flow valve designed to allow pressure to equalize across the valve, to no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour (0.57 cubic meters per hour); or

(B) For an excess flow valve designed to prevent equalization of pressure across the valve, to no more than 0.4 cubic feet per hour (.01 cubic meters per hour); and

(4) Not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

(b) An excess flow valve must meet the applicable requirements of Subparts B and D of this part.

(c) An operator must mark or otherwise identify the presence of an excess flow valve in the service line.

(d) An operator shall locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply.

(e) An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.

[Issued by Amdt. 192-79, 61 FR 31449, June 20, 1996; Amdt. 192-80, 62 FR 2618, Jan. 17, 1997; Amdt. 192-85, 63 FR 37500, July 13, 1998; and Amdt. 192-121, 81 FR 70987, Oct. 14, 2016]

GUIDE MATERIAL

1 GENERAL

The following provides operators with guide material when using an Excess Flow Valve (EFV). See guide material under §192.3 for the definitions of EFV, EFV-Bypass (EFVB), and EFV-Non-Bypass (EFVNB).

2 PERFORMANCE CONSIDERATIONS

The performance characteristics of an EFV should be published by the manufacturer. The published information should include the manufacturer's assigned product description or model number. Additional information can be found in the following references.

(a) Performance criteria: MSS SP-115, "Excess Flow Valves, NPS 1 1/4 and smaller, for Fuel Gas Service."

(b) Performance criteria: MSS SP-142, "Excess Flow Valves for Fuel Gas Service, NPS 1½ through 12."

(c) Test method: ASTM F1802, "Standard Test Method for Performance Testing of Excess Flow Valves."

(d) Specification: ASTM F2138, "Standard Specification for Excess Flow Valves for Natural Gas Service."

2.1 *Pressure or related limitations.*

(a) The EFV should function without unintended closure within the manufacturer's operating pressure limits.

(b) The EFV should not be damaged by test pressures or corresponding flow rates that may be uncontrolled.

2.2 *Reset of the EFV.*

The EFV should be capable of being reset through automatic or manual means. Currently, there are two basic designs:

(a) EFVB: Automatic. When selecting an EFVB, which provides automatic reset, consideration should be given to the reset time and the volume under the worst-case system conditions.

(b) EFVNB: Manual. The EFVNB may be used to provide complete shutoff of all gas flow. Once activated, a manual reset capability should be available, such as back-pressuring the line. The maximum leakage through an EFVNB should be in accordance with either MSS SP-115 or MSS SP-142, as applicable.

2.3 *Flow rates during operation.*

- (a) According to §192.381(a) for excess flow valves required by §192.383(b), the EFV closure flow rate is required to be no less than the manufacturer's rating at 10 psig. Further, the closure flow rate is to be no greater than 50% above the manufacturer's established rate at the respective EFV inlet pressure. For other situations, the closure flow rate should be no less than the manufacturer's established limits.
- (b) When subjected to snap-acting loads, the EFV should not close as the flow rate changes abruptly from a base steady flow to one equal to, or greater than, the typical customer's peak load, provided that the load is not greater than the minimum trip point of the EFV.

2.4 *Contamination.*

The manufacturer should demonstrate by accelerated testing that, over time, the EFV closure flow rate will not adversely decrease, nor will the reset characteristics change as a result of exposure to normal system contaminants that may occur over the life of the EFV.

2.5 *Pressure drop.*

The pressure drop across the EFV at the manufacturer's minimum recommended inlet pressure should not impair the ability to meet the customer's peak flow requirements.

3 **SELECTION CONSIDERATIONS**

EFVs should be selected based on loads, pressures, line lengths, internal diameter, gas density, and other operating conditions. The operator should consider the following.

3.1 *Placement.*

The placement of the EFV should take into account the geometry of various tapping tees and other methods of lateral connection that may cause turbulence and other flow conditions that could affect EFV performance. See 4.1 below.

3.2 *Pressure and flow.*

- (a) Considerations when selecting an EFV are as follows.
 - (1) Pressure drop across the EFV.
 - (2) Minimum operating pressure of the supply system.
 - (3) Anticipated maximum connected load.
 - (4) Size (internal diameter) and length of downstream piping.
- (b) The EFV should not be installed where the operating pressure extremes experienced at the valve inlet are reasonably expected to fall outside the manufacturer's established operating pressure limits.
- (c) Surge conditions may cause some EFVs to close unexpectedly and should be avoided when possible. Repressurize the distribution system slowly in order to prevent unintentional closure of EFVs. These conditions may result from restoration of pressure following construction activity, customer curtailment, cold weather peak demand, or other activity that may affect pressure and flow in a short time period.

3.3 *In-line components.*

- (a) The pressure drop associated with service line components may have an effect on the performance of the EFV.
- (b) The characteristics of the meter set should be reviewed, including the minimum inlet pressure to the regulator, to ensure that the necessary flow is provided under all operating conditions. The EFV selected should be compatible with these conditions.

3.4 *Changes in gas density.*

Changes in gas density due to peak shaving, such as propane-air mixtures, may alter the closure flow characteristics.

3.5 *Snap-acting loads.*

Snap-acting loads, such as those associated with the firing of large gas equipment or by simultaneous firing of several gas appliances, may cause flow to change abruptly, particularly in non-residential service

lines. This may cause the flow to exceed the minimum trip point of the EFV, thus causing it to close.

4 INSTALLATION CONSIDERATIONS

The manufacturer's recommended procedures for installation of an EFV should be followed unless the operator establishes alternative procedures based on sound engineering considerations. The following are some general installation factors for consideration. Also, see guide material under §192.383 that addresses different examples involving single residences.

4.1 Farm taps.

For some installations, two-stage pressure regulation is used where a high pressure line (e.g., transmission line) is the source of supply. An operator may choose to install a second EFV upstream of the first-stage regulator, if desired, for protection of the high pressure portion of the line.

4.2 Contaminants.

During or prior to installation, foreign material (e.g., dirt, liquid, plastic pipe shavings) should be removed from the service line to prevent contaminants from entering the EFV.

4.3 Gas flow direction.

Ensure the EFV is properly oriented with the direction of gas flow.

4.4 Application of heat.

Exposure to heat when performing such tasks as tie-ins or coating applications should be controlled to avoid adversely affecting the EFV. To prevent damaging the mechanism, care should be taken on steel installations to keep welding heat away from the EFV. In some circumstances, a wet rag may be placed over the steel nipple housing the EFV when the valve is being welded in place. Otherwise the steel nipple housing the EFV should be of appropriate length to allow necessary weld heat dissipation.

4.5 Pressure testing.

When performing a pre-installation pressure test through the upstream lateral tee, a rapid re-pressurization of the line should be avoided because such action might damage or close the downstream EFV.

4.6 Post-installation activation test.

After installation, consider testing the EFV to ensure that it trips and then resets. To test, trip the EFV by venting the service line to atmosphere. Then, follow the manufacturer's reset procedure.

4.7 Purging a service line.

Care should be taken to avoid excess flow that would cause the EFV to close. Techniques to avoid closure include opening the meter valve slowly, using an orifice cap, or purging the service line through the regulator.

5 IDENTIFICATION CONSIDERATIONS

Marking and identifying that an EFV has been installed may be accomplished by one or more of the following.

- (a) Affixing a durable identifying tag to the exposed portion of the gas riser or meter set.
- (b) Indicating the presence of an EFV on maps or records.
- (c) Using GPS coordinates.
- (d) Using a passive electronic marker.
- (e) Other methods.

§192.383

Excess flow valve installation.

[Effective Date: 04/14/17]

(a) **Definitions.** As used in this section:

Branched service line means a gas service line that begins at the existing service line or is installed concurrently with the primary service line but serves a separate residence.

Replaced service line means a gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

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

(b) **Installation required.** An EFV installation must comply with the performance standards in §192.381. After April 14, 2017 each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated:

- (1) A single service to one SFR;
- (2) A branched service line to a SFR installed concurrently with a primary SFR service line (i.e., a single EFV may be installed to protect both service lines);
- (3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV;
- (4) Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation, based on installed meter capacity, and
- (5) A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.

(c) **Exceptions to excess flow valve installation requirement.**

- (1) The service line does not operate at a pressure of 10 psig or greater throughout the year;
- (2) The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer;
- (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or
- (4) An EFV meeting performance standards in §192.381 is not commercially available to the operator.

(d) **Customer's right to request an EFV.**

Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in paragraph (c) of this section may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.

(e) **Operator notification of customers concerning EFV installation.**

Operators must notify customers of their right to request an EFV in the following manner:

- (1) Except as specified in paragraphs (c) and (e)(5) of this section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e-billing notices.
- (2) The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks.
- (3) The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known.
- (4) The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (c) are not present, the operator must install an EFV at a mutually agreeable date.

(5) Operators of master-meter systems and liquefied petroleum gas (LPG) operators with fewer than 100 customers may continuously post a general notification in a prominent location frequented by customers.

(f) *Operator evidence of customer notification.*

An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106.

(g) *Reporting.* Except for operators of master-meter systems and LPG operators with fewer than 100 customers, each operator must report the EFV measures detailed in the annual report required by §191.11.

[Issued by Amdt. 192-83, 63 FR 5464, Feb. 3, 1998 with Amdt. 192-83 Correction, 63 FR 20134, Apr. 23, 1998; Amdt. 192-113, 74 FR 63906, Dec. 4, 2009 with Amdt. 192-113 Correction, 75 FR 5244, Feb. 2, 2010; Amdt. 192-116, 76 FR 5494, Feb. 1, 2011; Amdt. 192-121, 81 FR 70987 Oct. 14, 2016 with Amdt. 192-121 Correction, 81 FR 72739, Oct. 21, 2016]

GUIDE MATERIAL

1 EXCESS FLOW VALVES (EFV) INSTALLATIONS

1.1 *General.*

Unless one or more of four conditions listed in §192.383(c) is present (service line does not operate at a pressure of at least 10 psig throughout the year, contaminants in the gas stream could interfere with the EFV's operation or cause loss of service to the customer, EFV could interfere with required operation or maintenance activities such as blowing liquids from the line, or an EFV is not commercially available for the application), §192.383 requires an EFV to be installed at the time of installation of new or replaced service lines that serve the following.

- (a) A single-family residence.
- (b) A single-family residence on a branched service line that is installed concurrently with the primary single-family residence service line. A single EFV may be installed to protect both the primary and the branched service lines.
- (c) A single-family residence, that is branched from an existing service line that does not have an EFV.
- (d) A multi-family residence with a total meter capacity not exceeding 1,000 SCFH for the service line.
- (e) A single, small commercial customer with meter capacity not exceeding 1,000 SCFH.

1.2 *Service line supplying a single-family residence.*

As required by §192.383(b)(1) and except for the limitations of §192.383(c), an operator must install an EFV on a new or replaced service line to a single-family residence. The following illustrations (Figures 192.383A and 192.383B) show where an EFV should normally be installed on a service line to a single-family residence to comply with §192.381(d). For other EFV installation considerations, see guide material under §192.381.

EFV with Meter Located at Residence

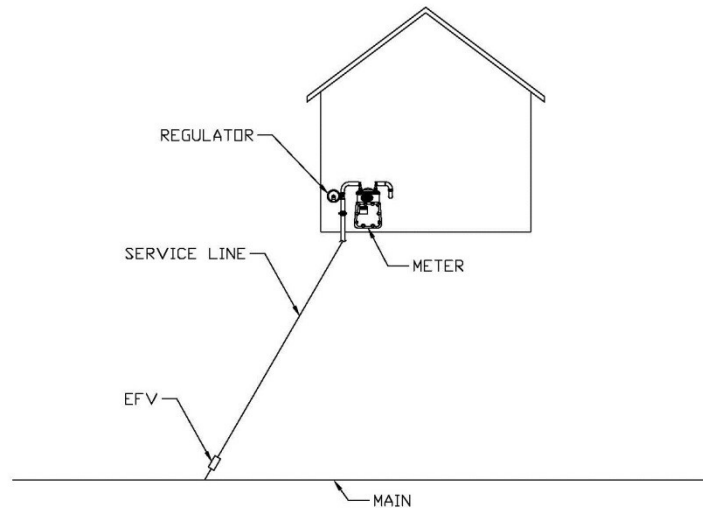


FIGURE 192.383A

EFV with Meter Located in the Vicinity of the Main

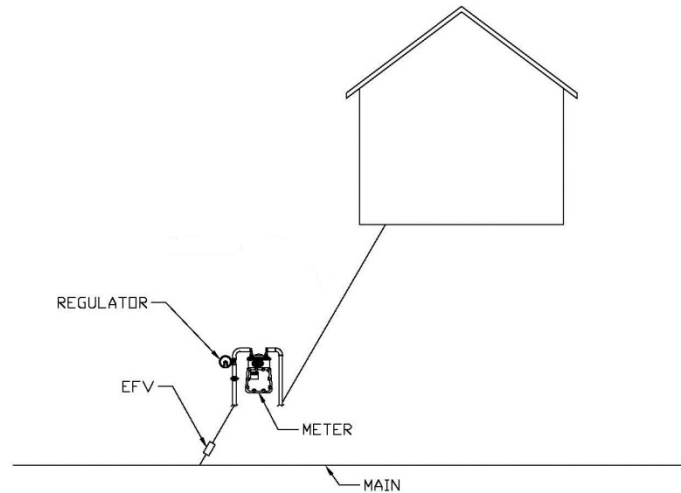


FIGURE 192.383B

1.3 Service line supplying adjacent single-family residences.

As required by §192.383(b)(2) and (3) and except for the limitations of §192.383(c), an operator must install an EFV on a new or replaced branch service line to adjacent single-family residences. Examples of a service line to adjacent single-family residences are illustrated in Figures 192.383C and 192.383D.

EFV for New or Replaced Service Line Serving Two Single-Family Residences with One EFV

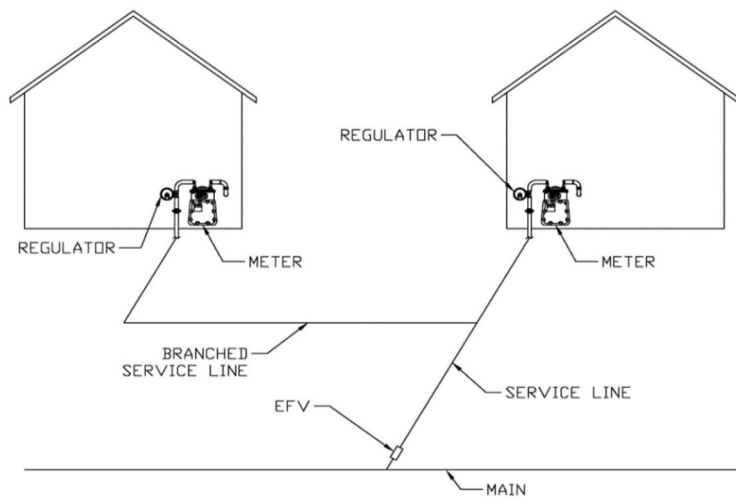


FIGURE 192.383C

Note: The branched service line may be installed at the same time as the original service line or it may be installed afterwards.

EFV for New or Replaced Branched Service on an Existing Single-Family Residence Service Line that Does Not Have an EFV

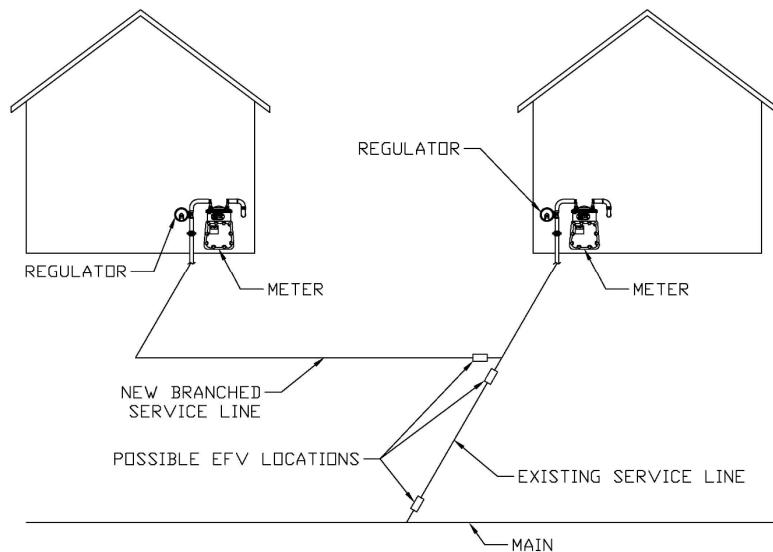


FIGURE 192.383D

Note: If a new or replaced branch service is installed from an existing service line that does not have an EFV, then the EFV may be placed in one of three possible locations as shown in the figure above.

1.4 Service line supplying a multi-family residence.

As required by §192.383(b)(4) and except for the limitations of §192.383(c), an operator must install an EFV on a service line to multi-family residences with a total meter capacity for the service line not exceeding 1,000 SCFH at the time of installation (Figure 192.383E).

EFV for Multi-Family Residence Where Total Meter Capacity for the Service Line Does Not Exceed 1,000 SCFH

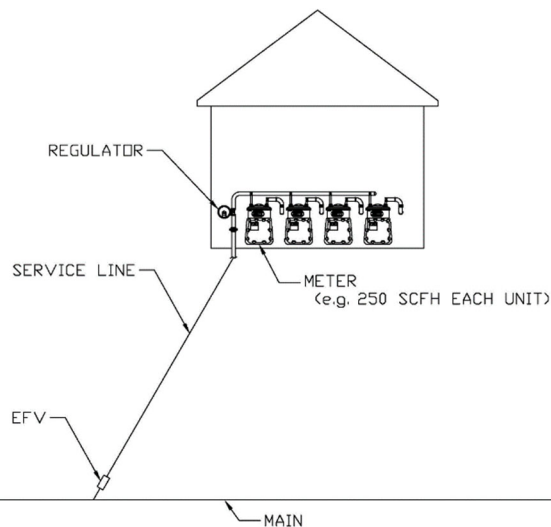


FIGURE 192.383E

1.5 Service line supplying a small commercial customer.

As required by §192.383(b)(5) and except for the limitations of §192.383(c), an operator must install an EFV on a service line to a small commercial customer with a meter capacity not exceeding 1,000 SCFH at the time of installation (Figure 192.383F).

EFV for Small Commercial Customer

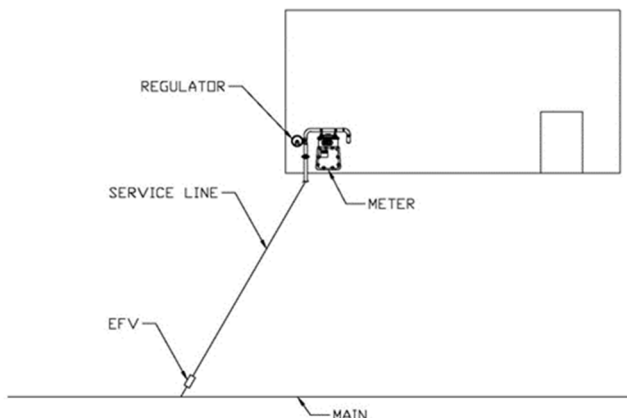


FIGURE 192.383F

§192.385

Manual service line shut-off valve installation.

[Effective Date: 04/14/17]

(a) **Definitions.** As used in this section:

Manual service line shut-off valve means a curb valve or other manually operated valve located near the service line that is safely accessible to operator personnel or other personnel authorized by the operator to manually shut off gas flow to the service line, if needed.

(b) **Installation requirement.** The operator must install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacity exceeding 1,000 SCFH.

(c) **Accessibility and maintenance.** Manual service line shut-off valves for any new or replaced service line must be installed in such a way as to allow accessibility during emergencies. Manual service shut-off valves installed under this section are subject to regular scheduled maintenance, as documented by the operator and consistent with the valve manufacturer's specification.

[Issued by Amdt. 192-121, 81 FR 70987, Oct. 14, 2016]

GUIDE MATERIAL

1 MANUAL SERVICE LINE SHUT-OFF VALVE INSTALLATION

1.1 General.

The following guide material describes the installation and maintenance of a manual service line shut-off valve (e.g., curb valve) required under §192.385. The purpose of this valve is to enable operators,

or other personnel authorized by the operator, to manually shut off gas flow to the service line, if needed. The manual service line shut-off valve described in this section does not refer to the riser valve or the meter shut-off valve at the meter set assembly located at the building where the service line terminates.

1.2 *Installation.*

Section 192.385 requires an operator to install either a manual service line shut-off valve or, if possible, based on sound engineering analysis and availability, an EFV for any new or replaced service line with installed meter capacities exceeding 1,000 SCFH. A manual service line shut-off valve should be located near the service main or a common source of supply to protect as much of the service line as is practicable.

Notes:

- (1) The installation of a manual service line shut-off valve on a service line to single family residence (SFR) or branched service line to an SFR, regardless of installed meter capacity, does not satisfy the requirement to install an EFV under §192.383.
- (2) The exceptions listed under §192.383(c) for the installation of an EFV do not apply to a manual service line shut-off valve.

1.3 *Accessibility and Maintenance*

A manual service line shut-off valve (e.g., curb valve) installed in accordance §192.385 must be installed in such a manner that it will be accessible in an emergency. This valve is subject to regularly scheduled maintenance consistent with the valve manufacturer's specification (or as specified by the operator if the manufacturer provides no specification), and the valve is to be accessible and operable. This maintenance may occur in conjunction with other activities when qualified personnel are present (e.g., meter-change programs, patrolling, leak surveys, activities where the service would be shut off). These valve maintenance requirements do not apply to valves that are installed in addition to an EFV.

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SUBPART I REQUIREMENTS FOR CORROSION CONTROL

§192.451

Scope.

[Effective Date: 09/05/78]

This subpart prescribes minimum requirements for the protection of metallic pipelines from external, internal, and atmospheric 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]

GUIDE MATERIAL

No guide material necessary.

§192.452

How does this subpart apply to converted pipelines and regulated onshore gathering pipelines?

[Effective Date: 04/14/06]

(a) *Converted pipelines.* Notwithstanding the date the pipeline was installed or any earlier deadlines for compliance, each pipeline which qualifies for use under this part in accordance with §192.14 must meet the requirements of the subpart specifically applicable to pipelines installed before August 1, 1971, and all other applicable requirements within 1 year after the pipeline is readied for service. However, the requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply if the pipeline substantially meets those requirements before it is readied for service or it is a segment that is replaced, relocated or substantially altered.

(b) *Type A and B regulated onshore gathering lines.* For any Type A or B regulated onshore gathering line under §192.9 existing on April 14, 2006, that was not previously subject to this part, and for any onshore gathering line that becomes a regulated onshore gathering line under §192.9 after April 14, 2006, because of a change in class location or increase in dwelling density:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31, 1971, apply only if the pipeline substantially meets those requirements.

(c) *Type C onshore regulated gathering lines.* For any Type C onshore regulated gathering pipeline under §192.9 existing on May 16, 2022, that was not previously subject to this part, and for any Type C onshore gas gathering pipeline that becomes subject to this subpart after May 16, 2022, because of an increase in MAOP, change in class location, or presence of a building intended for human occupancy or other impacted site:

(1) The requirements of this subpart specifically applicable to pipelines installed before August 1, 1971, apply to the gathering line regardless of the date the pipeline was actually installed; and

(2) The requirements of this subpart specifically applicable to pipelines installed after July 31,

1971, apply only if the pipeline substantially meets those requirements.

(d) *Regulated onshore gathering lines generally.* Any gathering line that is subject to this subpart per §192.9 at the time of construction must meet the requirements of this subpart applicable to pipelines installed after July 31, 1971.

[Issued by 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]

GUIDE MATERIAL

The operator should review the corrosion control records or perform field tests and surveys for a pipeline being converted according to §192.14 or a newly regulated segment of gathering line to ensure that cathodic protection can be applied to the pipeline to meet the requirements of Subpart I within 12 months of the conversion or becoming regulated. The tests and surveys may include electrical surveys, pipe examination, coating examination and soil tests. A record of the review or tests and surveys should be maintained.

§192.453

General.

[Effective Date: 02/11/95]

The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994]

GUIDE MATERIAL

1 PERSONNEL QUALIFICATIONS

Personnel responsible for directing the design, installation, operation, or maintenance of an operator's corrosion control systems should have knowledge of and practical experience in the following.

- (a) Pipeline coatings.
- (b) Cathodic protection (CP) systems (galvanic and impressed current).
- (c) Stray current interference.
- (d) Electrical isolation.
- (e) Survey methods and evaluation techniques.
- (f) Instruments used.

2 REFERENCE

A reference for the design and installation of CP systems is NACE SP0169, Sections 7 and 8.

§192.455

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

[Effective Date: 01/22/19]

(a) Except as provided in paragraphs (b), (c), (f), and (g) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of §192.461.

(2) It must have a cathodic protection system designed to protect the pipeline in accordance with this subpart, installed and placed in operation within 1 year after completion of construction.

(b) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience in the area of application, including, as a minimum, soil resistivity measurements and tests for corrosion accelerating bacteria, that a corrosive environment does not exist. However, within six months after an installation made pursuant to the preceding sentence, the operator shall conduct tests, including pipe-to-soil potential measurements with respect to either a continuous reference electrode or an electrode using close spacing, not to exceed 20 feet (6 meters), and soil resistivity measurements at potential profile peak locations, to adequately evaluate the potential profile along the entire pipeline. If the tests made indicate that a corrosive condition exists, the pipeline must be cathodically protected in accordance with paragraph (a) (2) of this section.

(c) An operator need not comply with paragraph (a) of this section, if the operator can demonstrate by tests, investigation, or experience that —

(1) For a copper pipeline, a corrosive environment does not exist; or

(2) For a temporary pipeline with an operating period of service not to exceed five years beyond installation, corrosion during the five-year period of service of the pipeline will not be detrimental to public safety.

(d) Notwithstanding the provisions of paragraph (b) or (c) of this section, if a pipeline is externally coated, it must be cathodically protected in accordance with paragraph (a) (2) of this section.

(e) Aluminum may not be installed in a buried or submerged pipeline if that aluminum is exposed to an environment with a natural pH in excess of 8.0, unless tests or experience indicate its suitability in the particular environment involved.

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

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

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

(g) Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of paragraph (f) must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-28, 42 FR 35653, July 11, 1977; Amdt. 192-39, 47 FR 9842, Mar. 8, 1982; 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 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

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

1 REFERENCES

NACE SP0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," as follows.

(a) For §192.455(a), see Sections 7, 8, and 9.

(b) For §192.455(b), see Section 3.

2 ISOLATED STEEL COMPONENTS IN PLASTIC PIPING SYSTEMS

Where an operator is unable to demonstrate by tests, investigation, or experience that cathodic protection (CP) is not required, one of the following methods may be used to protect isolated steel components in plastic piping systems.

- (a) A galvanic anode directly connected to the steel component. Although the anode lead may be used as a test station for monitoring CP under §192.465, a separate test lead may be installed so that damage to the test lead will not interfere with CP.
- (b) Each steel component may be connected to a tracer wire that is also connected to one or more galvanic anodes. To facilitate monitoring, the tracer wire may be terminated at one or more service risers. The operator should consider the impact that a tracer wire network might have on the anode's effectiveness to cathodically protect the steel component. Considerations may include:
 - (1) Installation of the proper size anode.
 - (2) The potential for damage to the tracer wire between the anode and the steel component.

The operator is cautioned that a break in the tracer wire could affect the protection and monitoring of the connected components. See 2 of the guide material under §192.321 for further information regarding tracer wires.

3 STRAY ELECTRICAL INTERFERENCE CURRENTS

Piping exposed to stray electrical interference currents may require protection and mitigation prior to the end of the one-year maximum time period stated in the Regulations. See guide material under §192.473.

§192.457

External corrosion control: Buried or submerged pipelines installed before August 1, 1971.

[Effective Date: 10/15/03]

(a) Except for buried piping at compressor, regulator, and measuring stations, each buried or submerged transmission line installed before August 1, 1971, that has an effective external coating must be cathodically protected along the entire area that is effectively coated, in accordance with this subpart. For the purposes of this subpart, a pipeline does not have an effective external coating if its cathodic protection current requirements are substantially the same as if it were bare. The operator shall make tests to determine the cathodic protection current requirements.

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

- (1) Bare or ineffectively coated transmission lines.
- (2) Bare or coated pipe at compressor, regulator, and measuring stations.
- (3) Bare or coated distribution lines.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-33, 43 FR 39389, Sept. 5, 1978; Amdt. 92-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

See guide material under §192.465 regarding "areas in which active corrosion is found."

§192.459

External corrosion control: Examination of buried pipeline when exposed.

[Effective Date: 11/22/99]

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under Secs. 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-87, 64 FR 56978, Oct. 22, 1999]

GUIDE MATERIAL

1 FIELD INVESTIGATION

The following may be considered when inspecting exposed pipe for external corrosion.

- (a) If no corrosion is found, further investigation is not required.
- (b) If corrosion is found, but the corrosion does not require remedial action (as required by §§192.483, 192.485, 192.487, and 192.489), repair or upgrade the cathodic protection system to prevent further corrosion, if applicable.
- (c) If corrosion requiring remedial action is found, perform an investigation by visual examination, an indirect method, or a combination of both to determine the extent of any additional detrimental corrosion in the vicinity of the exposed pipe. This investigation must be conducted both circumferentially and longitudinally. Procedures for additional investigation may include the following.
 - (1) Guidelines for determining when to use a visual examination or other methods.
 - (2) A list of operator-approved investigation methods, which might include additional excavation, electrical surveys, wall-thickness measurements, internal inspection tools, or other non-destructive testing methods.
 - (3) Allowable methods of inspection.
 - (4) Criteria for how much pipe must be found that does not require remedial action before stopping the investigation. These criteria might include location, diameter, operating pressure, or other factors.
 - (5) Guidelines for what to do if remedial action is required but cannot be performed immediately.
 - (6) Guidelines for when to contact a supervisor or other personnel who are qualified in corrosion control methods (see guide material under §192.453).
 - (7) Requirements for documentation.
- (d) If corrosion is found on a covered or non-covered segment of a transmission pipeline, see 5 below and §192.917(e)(5).
- (e) Repair of any coating damage caused or found during an inspection.
- (f) Consider performing an appropriate nondestructive inspection technique to determine whether SCC exists.

2 FIELD REPORT

A field work report or similar form is useful for describing the condition of the coating or exposed pipe surface in qualitative terms. General criteria for rating the existing conditions should be established system-wide to provide for consistency in field reporting and analysis. Where possible, the report or form should include the following.

- (a) An evaluation of the coating condition.

- (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 10.2 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; and

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Addendum 4, May 2024

(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 dB μ V 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

This guide material is under review following Amendment 192-132.

1 GENERAL

Each operator should specify protective coatings for factory-applied and field-applied coatings to meet the requirements stated in §192.461. Materials purchased with factory-applied coatings should include references to the appropriate industry standard for the coating selected with options such as platings and overlays clearly indicated. Field-applied coating requirements should state the expectation to follow manufacturer application instructions including appropriate surface preparation.

2 FACTORY APPLIED COATINGS

When purchasing materials with factory-applied coatings, operators should ensure coating materials selected and the application processes will be appropriate for the service conditions (e.g., below ground, above ground) and method of installation. For horizontal directional drilling (HDD) installations, see Guide Material Appendix G-192-15A, Section 5.3. Designation of the coating requirements could be an operator-developed material purchase specification for certain items (example 1) or just review and acceptance of manufacturer coating processes (example 2).

Addendum 2, February 2023

Addendum 3, July 2023

Addendum 4, May 2024

(a) Example 1:

A steel line pipe coating specification for fusion bonded epoxy may refer to NACE SP0394 (see 7 below) and add requirements such as the following.

- (1) Approved coating type and manufacturer of the Fusion Bonded Epoxy and Abrasion Resistant Overlay.
- (2) Frequency of soluble salt testing.
- (3) Coating thickness (i.e., minimum, maximum, average).
- (4) Allowance of recycled materials.
- (5) Production inspection above and beyond industry specification.
- (6) Allowable holiday repairs.

(b) Example 2:

Manufacturers of risers, transition fittings, valves, and meter assemblies typically have standard coating materials and application processes for their product. Operators should review the manufacturer coating information, determine the appropriateness for the intended application, and document the acceptance. Considerations in the review process might include the following.

- (1) ASTM B117 salt spray test results.
- (2) Ensuring product free of water, dust, dirt, oil, or grease prior to coating.
- (3) Surface preparation procedures.
- (4) Coating material accommodating of all surfaces without cracking, disbonding, or flaking.
- (5) Coating options such as:
 - (i) 2-part epoxy primer and enamel overlay,
 - (ii) 2-part epoxy primer and 2-part urethane overlay, or
 - (iii) Zinc plating, 2-part epoxy primer, and 2-part urethane overlay.

3 FIELD-APPLIED COATINGS

(a) There are numerous situations where field application of coatings is required during new pipeline installation, maintenance, and repair activities. Examples include weld joints, service tees, buried valves, thermowelds, and meter assembly maintenance. Compatibility of field-applied coatings with the associated factory-applied coatings should be a consideration in the selection. Due to the variables in the field compared to factory conditions, minimizing the amount of field applications is generally preferred.

(b) Typical field-applied coatings for the applications stated above include liquid epoxy, cold applied tape, hot applied tape, mastic, wax wrap, and shrink sleeves. Operators should specify the appropriate field applied coating for the conditions anticipated and provide manufacturer instructions for application.

(c) Surface preparation of the metallic surface is critical to achieve proper bonding with the coating material. Operators should specify expectations for surface preparation for the various situations that will typically be encountered.

- (1) Bare steel should be free of water, dust, dirt, grease, oil, and other foreign matter.
- (2) Welds should be free of slag, splatter, and scale.
- (3) Sharp edges or burrs should be removed by filing or grinding.
- (4) Blast cleaning, if required, should be to a NACE No. 2/SSPC-SP10 finish.
- (5) Repair area should be dry and at a temperature at least 5 degrees above the dew point.
- (6) Surfaces with oil, grease, pipe thread sealant, or other soluble surface contamination may be cleaned with an approved solvent provided it does not have a detrimental effect on the coating material.
- (7) If primer is required, application details should be provided.

4 COATING INSPECTION

(a) The inspection of coatings is an important precautionary measure to ensure defects are identified prior to placing a facility in service. Operators should consider viable opportunities to validate coating integrity during coating application processes, following transportation and other logistical steps, during construction, and post-construction. Methods of inspection might include visual

checks, thickness measurements where appropriate, electrical inspection for pipe (typically referred to as jeeping or holiday detection), and for significant facilities, post-construction indirect electrical measurement techniques (e.g., current drain tests, DCVG, close interval surveys).

- (b) Operators should review manufacturer inspection requirements in the factory application processes. After delivery to warehouses or construction sites, inspect materials for visible damage.
- (c) Inspect pipe coatings while pipe is being lowered into a trench by jeeping or holiday detection (see 4(d) below), and during backfill operations (see 3 of the guide material under §192.319). Pipe handling equipment such as rollers, slings, and chains should be selected and maintained to avoid potential coating damage during use. Backfilling operations should include procedures to ensure that materials contacting the pipe do not cause coating damage. Use of supplemental protection such as rockshield may also be considered.
- (d) The holiday detection test is intended to detect voids, cracks, or contaminants in the coating that may lower the electrical resistance or dielectric strength of the coating. Operators should consider procedures specific to holiday detection that include the appropriate equipment to perform the test, voltage settings per coating type and thickness, requirements by pipe size, length and coating material, and pipe cleanliness expectations. The holiday detection test should be performed prior to lowering the pipe into the trench in order to identify any damage that may occur in the installation process. See NACE documents related to holiday detection in 7 below.
- (e) Electrical measurements that can provide indications of coating integrity can be implemented as a further method of inspection. These techniques might require special resources so the operator should consider use of these for facilities deemed at special risk or for significant projects. Examples of these methods include current drain tests, DCVG, and close interval surveys.

5 ADVERSE DITCH CONDITIONS AND SUPPORT BLOCKS (§192.461(d))

- (a) During pipe installation in ditch conditions that could cause coating damage or electrical shielding, preventative measures should be taken to protect the pipe and coating. Measures to consider include the following.
 - (1) Grading ditch bottom to remove rocks or other foreign matter.
 - (2) Use of bedding sand.
 - (3) Screening of backfill to remove rocks or other detrimental debris.
 - (4) Additional coating protection such as rockshield.
- (b) Pipe supported over a trench should be placed on padded skids of sufficient size to safely support the pipe weight. If blocking is used to support valves or other assemblies, protective material that will not cause electrical shielding should be considered.

6 BORING OR DRIVING (§192.461(e))

See 2 of the guide material under §192.361.

7 REFERENCES

- (a) ASTM B117, "Standard Practice for Operating Salt Spray (Fog) Apparatus" - (§192.461(a)(1)-(4)).
- (b) NACE No. 2/SSPC-SP 10, "Near-White Metal Blast Cleaning" - (§192.461(a)(1)).
- (c) Section 5 of NACE SP0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems" – (§192.461(a), (b), and (d)).
- (d) NACE SP0188, "Discontinuity (Holiday) Testing of New Protective Coatings on Conductive Substrates" - (§192.461(c)).
- (e) NACE SP0274, "High Voltage Inspection of Pipeline Coatings" - (§192.461(c)).
- (f) Section 5 of NACE SP0375, "Field-Applied Underground Wax Coating Systems for Underground Metallic Pipes: Application, Performance, and Quality Control" - (§192.461(d)).
- (g) NACE SP0394, "Application, Performance, and Quality Control of Plant-Applied Single Layer Fusion-Bonded Epoxy External Pipe Coating."
- (h) NACE SP0490, "Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coating of 250 to 760 µm (10 to 30 mil)" - (§192.461(c)).

§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 power 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.

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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

This guide material is under review following Amendment 192-132.

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 PERIODIC INSPECTION OF CATHODIC PROTECTION RECTIFIERS AND IMPRESSED CURRENT POWER SOURCES (§192.465(b))

- (a) Inspections are needed to confirm adequate amperage and voltage for providing cathodic protection and must be conducted 6 times each year at intervals not exceeding 2½ months either on site or remotely (§192.465(b)).
- (b) At least one annual inspection at intervals not to exceed 15 months must take place physically on site to ensure safe and continued operation of the equipment (§192.465(b)). One of the six bi-monthly inspections may be used for this onsite inspection as long as the timing meets the annual physical inspection requirement. Considerations for the inspection include:
 - (1) Visual inspection for physical damage due to vandalism, lightning, wildlife, downed trees, etc.
 - (2) Verification of rectifier settings.
 - (3) Direct amperage and voltage readings compared to remote device readings.
 - (4) Pipe to soil potentials.
 - (5) Electric meter readings.
 - (6) Documentation that notes conditions observed and follow up expectations for remediation.
- (c) Operators using remote rectifier read processes should consider what documentation is necessary to demonstrate compliance. Such remote inspection documentation may include the following.
 - (1) Facility identification descriptions.
 - (2) Voltage and amperage reads on designated dates to demonstrate regulatory time frames.
 - (3) Remarks to provide clarifications, non-typical observations, or follow up required.

3 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. If remotely read rectifiers indicate potential deficiencies (e.g., voltage/amperage out of acceptable range, loss of power, loss of signal), operators must have procedures to initiate an onsite investigation. (§192.465(d)).
- (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.

4 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 10 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 10.2 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.

5 DETERMINING ACTIVE CORROSION ON UNPROTECTED PIPELINES

5.1 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.

5.2 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.

6 "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.

7 CORRECTING ACTIVE CORROSION ON UNPROTECTED PIPELINES

7.1 *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.

7.2 *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 appropriate. If corrective action cannot be completed within 15 months, the operator should document the actions taken and the expected timeframe for completion.

7.3 *Reference.*

AGA XL0702, "Distribution Pipe: Repair and Replacement Decision Manual."

8 MONITORING OF CATHODICALLY PROTECTED AREAS ON UNPROTECTED PIPELINES (§192.465(a))

8.1 "Active" corrosion areas.

See 5 and 7 above. For areas of local corrosion protection provided by galvanic anodes at individual locations of active corrosion, the anodes need to provide a level of CP that complies with §192.463. Monitoring is required in accordance with §192.465(a).

8.2 "Not active" corrosion areas.

See 6 above. For areas of local protection provided by galvanic anodes at individual locations of "not active" corrosion, the corrosion protection levels are not subject to the requirements of §192.463. Such "voluntarily installed" anodes need not be monitored in accordance with §192.465(a), but the pipeline must be reevaluated every three years at intervals not exceeding 39 months in accordance with §192.465(e).

9 MONITORING OF UNPROTECTED PIPELINES (§192.465(e))

Every three years at intervals not exceeding 39 months, unprotected pipelines are required to be reevaluated to identify areas of active corrosion in accordance with §192.465(e). Electrical surveys are

required except as follows.

- (a) Where electrical survey is impractical, the study of failures, leakage history, corrosion, class location, hazard to the public, and unusual operating/maintenance conditions may be used to evaluate the need for protection.
- (b) Where the pipeline is remotely located or otherwise determined that corrosion caused leaks would not be a detriment to public safety.

10 USING ELECTRICAL-TYPE SURVEYS FOR UNPROTECTED PIPELINES

10.1 Methods.

- (a) The following are examples of electrical-type surveys.
 - (1) Pipe-to-soil potential measurement. Where practical, this electrical survey is required by §192.465(e) to determine areas of active corrosion on transmission lines.
 - (2) Soil resistivity measurement.
 - (3) Dual electrode or earth gradient measurement.
 - (4) Line current measurement.
- (b) Except for pipe-to-soil potential surveys, if other electrical-type surveys are used to determine areas of active corrosion, §192.465(e) requires a review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

10.2 Applicability

Where electrical-type surveys are considered for use in determining corrosion areas, the operator should consider the following conditions that may make these surveys impractical to apply or ineffective, or may result in unreliable data.

- (a) Stray earth gradient. Telluric currents, iron ore deposits, A.C. induction, and other sources create stray earth potential gradients that may make it difficult to reliably interpret electrical surveys.
- (b) Lack of electrical continuity. The facility may not be electrically continuous due to unknown insulators or other high resistance joining methods, such as gasketed joints and, on occasion, lack of continuity on threaded connections. These discontinuities may be intermittent with time.
- (c) Pavement and congestion. Electrical-type surveys are complicated in congested areas where frequent pipe contact is necessary. Paved streets and sidewalks prevent ready access to the soil contact required for the copper sulfate electrode and also limit ability to contact the pipe itself.
- (d) Electrical isolation. Facilities that are not electrically isolated are often in direct contact with other metallic structures or in indirect contact with these structures through the earth, house plumbing, wiring, or electrical grounding systems. Where such contacts exist, electrical surveys are either ineffective or may erroneously indicate corrosion problems. For example, an unknown contact between a steel pipeline and aluminum, zinc, or galvanized metal would indicate an electro-negative peak on a pipe-to-soil survey that may erroneously be interpreted as a corrosive condition on the pipeline.
- (e) Shielding of CP current. CP current can be shielded from the pipeline by nearby objects close to the pipeline. The current can be picked up by nearby conducting elements such as casings, parallel or crossing lines, scrap metal, or other foreign objects. Non-conducting elements close to the pipeline can also shield or limit the current to the pipeline. Such elements could be disbanded coating, rocks, solid-type abrasion protection or rock shield material (i.e., material that would shield CP current), rock ledges, or concrete structures. The shielding effects can go undetected by an electrical survey due to the many combinations of the size and location of shielding objects.
- (f) Sufficiency of history and details of facilities. Correct interpretation of electrical measurements on gas facilities depends on detailed knowledge of the age and types of material installed, maintenance history, location of galvanic anodes, coating, foreign facilities, location and types of service lines, joining methods, and unusual soil conditions. For example, the installation of insulators after the facilities have been in service will alter the significance of previous electrical survey data.
- (g) Other conditions.
 - (1) Extremely dry soil.
 - (2) Adjacent underground facilities.

- (h) Practicability. The extreme hardship or expense of obtaining a meaningful electrical survey may render a survey inappropriate for a given pipeline because of the above or other conditions.

11 IN-LINE INSPECTION SURVEYS

An increase in the number or severity of corrosion defects discovered during assessments might indicate that remedial action is needed (see 3 above). For information about in-line inspection surveys, see Guide Material Appendix G-192-14.

§192.467

External corrosion control: Electrical isolation.

[Effective Date: 09/05/78]

(a) Each buried or submerged pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structures are electrically interconnected and cathodically protected as a single unit.

(b) One or more insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) Except for unprotected copper inserted in ferrous pipe, each pipeline must be electrically isolated from metallic casings that are a part of the underground system. However, if isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline inside the casing.

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

(e) An insulating device may not be installed in an area where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

(f) Where a pipeline is located in close proximity to electrical transmission tower footings, ground cables or counterpoise, or in other areas where fault currents or unusual risk of lightning may be anticipated, it must be provided with protection against damage due to fault currents or lightning, and protective measures must also be taken at insulating devices.

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GUIDE MATERIAL

1 INSPECTION AND TESTING (§192.467(d))

The required monitoring of cathodic protection (CP) systems and the evaluation of CP test data is generally sufficient to ensure that electrical isolation is adequate on cathodically protected piping. However, specific electrical tests on insulating devices should be made where deemed necessary to ensure the adequacy of electrical isolation and to pinpoint operational problems on CP systems. The operator should establish criteria for casing and carrier pipe CP readings that indicate a metallic short or electrolytic contact. Factors to consider when establishing criteria include the following.

- (a) Capabilities of equipment.
- (b) Environment of casing and carrier pipe.
- (c) Coated versus bare pipe.
- (d) Depth of casing.

2 ELECTRICAL ISOLATION (§192.467(a), (b), and (c))

2.1 Insulating devices. (§192.467(a) and (b))

Insulating devices may consist of insulating flange assemblies (see guide material under §192.147), unions or couplings, or fabricated insulating joints. These devices should be properly rated for temperature, pressure, and dielectric strength. Typical locations where electrical insulating devices should be considered include the following.

- (a) At supporting pipe stanchions, bridge structures, tunnel enclosures, piling, and reinforced concrete foundations where electrical contact would preclude effective cathodic protection (CP). It may be necessary to electrically isolate the piping from such a structure, or the piping and structure from adjacent underground piping.
- (b) At metallic curb boxes and valve enclosures. These should be designed, fabricated and installed in such a manner that electrical isolation from the piping system will be maintained.
- (c) Where a pipe enters a building through a metallic wall sleeve and where it is intended to maintain electrical isolation between the sleeve and the pipe. To accomplish this, insulating spacers should be used.
- (d) At river weights, pipeline anchors, and metallic reinforcement in weight coatings. These should be electrically isolated from the carrier pipe and installed so that coating damage will not occur.
- (e) Points at which facilities change ownership, such as meter stations and well heads.
- (f) Connections to main line piping systems, such as gathering or distribution system laterals.
- (g) Inlet and outlet piping of inline measuring or pressure regulating stations or both.
- (h) Compressor or pumping stations, either in the suction and discharge piping or in the main line immediately upstream and downstream of the station.
- (i) In stray current areas.
- (j) At the termination of service line connections and entrance piping to prevent electrical continuity with other metallic systems.

2.2 Casings. (§192.467(c))

- (a) New installations.
 - (1) *Spacers and sealing.* All new construction of cased metallic pipelines should provide for the installation of insulating type casing spacers or other suitable means to prevent physical contact between the carrier pipe and casing. The ends of the casing may be sealed with a non-conductive sealing method to prevent mud, silt, and water from entering the annular space between the casing and the carrier pipe. It may be necessary to fill this annular space with a non-conductive type casing filler to ensure continued isolation in those installations where end seals alone may not be sufficient to resist the entrance of water.
 - (2) *Joining.* Lengths of casing should be joined by a full weld, or other type of joint that will provide an adequate seal against water entrance. Any holes in the casing should be closed by welding, or otherwise sealed.
 - (3) *Insertion.* Care should be taken during installation to reduce the possibility of electrical shorts. The carrier pipe should be as straight as practical. The internal diameter of the casing should be adequate to ensure physical clearance from the carrier pipe. The carrier pipe should be carefully inspected and all coating damage repaired. Care should be taken during insertion of the carrier pipe. To prevent damage to the coating and spacer, the casing should be clear of any mud, water, or debris prior to insertion of the carrier pipe. When existing buried pipe is being used as the casing, steps should be taken to ensure that the casing pipe is free of weld protrusions and other obstructions that might cause jamming of the carrier pipe during insertion.

Where insulating-type casing spacers are used, one should be installed as close as practical to each end of the casing. Vent connections, when required, should be installed prior to the insertion of the carrier pipe to preclude the possibility of damage to the carrier pipe.

- (b) Existing installations.
 - (1) Where there is an indication that corrosion is occurring on the carrier pipe or where a CP installation is rendered inadequate as a result of low resistance between the casing and carrier pipe (i.e., the pipe-to-soil and the casing-to-soil readings are essentially the same), the operator should test the casing to confirm if a metallic short or electrolytic contact actually exists. It is recommended that the casing be tested within one year of discovering the

- indication. Consideration should be given to additional measures such as leakage surveys (see (3)(iv) below) until the test is conducted.
- (2) The following are types of tests that can be used to determine if a carrier pipe is likely to be in metallic or electrolytic contact with a casing. For guidance on how to perform these types of tests, see the related source documents.
 - (i) Direct Current Voltage Gradient (DCVG) – Reference NACE TM0109, “Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition.”
 - (ii) AC current attenuation – Reference NACE TM0109, “Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition.”
 - (iii) Alternating Current Voltage Gradient (ACVG) – Reference NACE TM0109, “Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition.”
 - (iv) Potential surveys – Reference NACE TM0497, “Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems.”
 - (A) Potential Surveys (CIS, No Interruption).
 - (B) Potential Surveys (CIS, Interrupted).
 - (v) Pipe or cable locator – Reference NACE SP0200, “Steel-Cased Pipeline Practices.”
 - (vi) Current span test / Four-Wire Drop Test – Reference NACE SP0200, “Steel-Cased Pipeline Practices.”
 - (vii) Internal resistance test – Reference NACE SP0200, “Steel-Cased Pipeline Practices.”
 - (viii) Panhandle Eastern Test.
 - (ix) Casing or pipe capacitance.
 - (x) Temporary intentional short.
 - (3) Mitigative measures.
 - (i) Electrolytic contact. If the test determines that an electrolytic contact exists (water or dirt in contact with the pipeline at a coating holiday), an operator may choose one or more of the following measures to eliminate the contact.
 - (A) Clean out the casing and replace or repair the end seals on the casing.
 - (B) Fill the annular space between the carrier pipe and casing with a non-conductive (i.e., dielectric) filler. When filling the annular space, the operator should confirm that the actual amount of fill material is consistent with the annular volume. For additional installation guidance, see NACE SP0200, “Steel-Cased Pipeline Practices.”
 - (C) Replace with an uncased pipeline.
 - (D) Remove the casing if the carrier pipe has sufficient strength for the anticipated stresses and determine if the requirements of §192.111 are applicable for the uncased crossing.
 - (ii) Metallic short. If the test determines that a metallic short exists, an operator may choose one or more of the following measures to eliminate or mitigate the short.
 - (A) Clear the short. It may be practical to expose the ends of the casing and physically realign the carrier pipe to give enough clearance for inserting a non-conductive material in the annular space between the casing and carrier pipe. The feasibility of safely moving the carrier pipe to clear a short should be determined prior to performing the work. See 4 of the guide material under §192.703.
 - (B) Fill the annular space. The space between the carrier pipe and casing may be filled with a non-conductive (i.e., dielectric) material. When filling the annular space, the operator should confirm that the actual amount of fill material is consistent with the annular volume.
 - (C) Replace with an uncased pipeline.
 - (D) Remove the casing if the carrier pipe has sufficient strength for the anticipated stresses and determine if the requirements of §192.111 are applicable for the uncased crossing.
 - (iii) Completion check. The operator should verify the effectiveness of mitigative actions taken under 2.2(b)(3)(i) or (ii) above. For the types of tests, see 2.2(b)(2) above.
 - (iv) Interim action. It is recommended that until one of the above measures can be implemented, the operator should consider one or more of the following actions.

- (A) Conduct instrumented leak detection inspections at the same intervals as prescribed for patrolling in §192.705.
- (B) Review existing in-line inspection (ILI) tool runs to determine the condition of the pipe inside the casing.
- (C) Run an ILI tool that detects metal loss on the carrier pipe.
- (D) Perform Guided Wave Ultrasonic Technology (GWUT) on the carrier pipe in the casing.

3 COMBUSTIBLE ATMOSPHERE (§192.467(e))

- (a) Precautions to prevent arcing may be taken by installing galvanic anode type grounding cells or commercial lightning or fault arrestors across the insulating devices.
- (b) Where lightning arrestors are installed across insulating devices within a building or other confined space anticipated to have a combustible atmosphere, the physical installation of the lightning arrestors should be made outside the confined space. Electrical conductors of adequate size should be installed from the insulating point to the lightning arrestors.

4 PROTECTION OF INSULATING DEVICES (§192.467(f))

It is recommended that the operator make a study in collaboration with the electric company on the common problems of corrosion and electrolysis, taking into consideration the following factors.

- (a) The possibility of the pipeline carrying either unbalanced line currents or fault currents.
- (b) The possibility of lightning or fault currents inducing voltages sufficient to puncture pipe coatings or pipe.
- (c) CP of the pipeline, including the location of ground beds. (This is particularly important if the electric line is carried on steel towers.)
- (d) Bonding connections that exist between the pipeline and the overhead electric system at the following.
 - (1) The steel tower footing.
 - (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

This guide material is under review following Amendment 192-132.

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/m³) 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.

Addendum 2, February 2023

Addendum 4, May 2024

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.

- (i) Gas being transported.
- (ii) Downstream gas utilization and processing equipment.
- (iii) Any other treatments.

6 REFERENCES

- (a) See 2 of the guide material under §192.53.
- (b) GRI-02/0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology."
- (c) NACE MR0175, "Materials for Use in H₂S-Containing Environments in Oil and Gas Production."
- (d) NACE RP0175, "Control of Internal Corrosion in Steel Pipelines and Piping Systems" (Revised 1975; Discontinued).
- (e) NACE SP0192, "Monitoring Corrosion in Oil and Gas Production with Iron Counts."
- (f) NACE SP0775, "Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations."
- (g) NACE TM0194, "Field Monitoring of Bacterial Growth in Oilfield Systems."
- (h) NACE 3D170, Technical Committee Report, "Electrical and Electrochemical Methods for Determining Corrosion Rates" (Revised 1984; Withdrawn 1994).
- (i) "Evaluation of Chemical Treatments in Natural Gas System vs. MIC and Other Forms of Internal Corrosion Using Carbon Steel Coupons," Timothy Zintel, Derek Kostuck, and Bruce Cookingham, Paper # 03574 presented at CORROSION/03 San Diego, CA.
- (j) "Field Guide for Investigating Internal Corrosion of Pipelines," Richard Eckert, NACE Press, 2003.
- (k) "Field Use Proves Program for Managing Internal Corrosion in Wet-Gas Systems," Richard Eckert and Bruce Cookingham, Oil & Gas Journal, January 21, 2002.
- (l) "Internal Corrosion Direct Assessment," Oliver Moghissi, Bruce Cookingham, Lee Norris, and Phil Dusek, Paper # 02087 presented at CORROSION/02 Denver, CO.
- (m) "Internal Corrosion Direct Assessment of Gas Transmission Pipeline - Application," Oliver Moghissi, Laurie Perry, Bruce Cookingham, and Narasi Sridhar, Paper # 03204 presented at CORROSION/03 San Diego, CA.
- (n) "Microscopic Differentiation of Internal Corrosion Initiation Mechanisms in a Natural Gas System," Richard Eckert, Henry Aldrich, and Chris Edwards, Bruce Cookingham, Paper # 03544 presented at CORROSION/03 San Diego, CA.

§192.476

Internal corrosion control: Design and construction of transmission line.

[Effective Date: 05/23/07]

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

- (1) Be configured to reduce the risk that liquids will collect in the line;
- (2) Have effective liquid removal features whenever the configuration would allow liquids to collect; and
- (3) Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion.

(b) **Exceptions to applicability.** The design and construction requirements of paragraph (a) of this section do not apply to the following:

- (1) Offshore pipeline; and

(2) Pipeline installed or line pipe, valve, fitting or other line component replaced before May 23, 2007.

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

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

[Issued by RIN 2137-AE09, 72 FR 20055, Apr. 23, 2007]

GUIDE MATERIAL

1 GENERAL

This guide material addresses liquids that cause internal corrosion (i.e., liquids that contain water).

- (a) In accordance with NACE SP0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems," if liquid water is not present in the steel pipeline, corrosion will not occur. Section 192.476 uses the term "*liquids*" when the concern of internal corrosion pertains only to liquids that act as an electrolyte (liquid water). The term "*liquid water*" will be used in the guide material.
- (b) NACE SP0106 states that because of the complex nature and interaction between constituents (e.g., carbon dioxide, hydrogen sulfide) that are found in gas or liquid water, certain combinations of these impurities transported in the pipeline might affect whether a corrosion condition exists. Appendix A (non-mandatory) of this standard provides an example of a typical gas quality specification.
- (c) The term "*significant potential for internal corrosion*" as used in §192.476(a)(3) means that the risk of internal corrosion is known to exist in like situations to the degree that the serviceability or the design life of the pipeline segment might be negatively affected.

2 DETERMINATION OF WHAT CONSTITUTES IMPRACTICABLE AND UNNECESSARY

2.1 *Impracticable.*

Examples of conditions that may make it impracticable to design and construct features to reduce the risk of internal corrosion include the following. For most of these examples, the operator should consider installing liquid water removal or monitoring devices at an upstream location feasible for installation.

- (a) A low spot or angle created when a pipeline segment is bored in and where liquid water is expected to accumulate.
- (b) Pipeline segments installed in casings in such a configuration that liquid water is expected to accumulate.
- (c) Water crossings or where pipeline segments are installed in marshes.
- (d) Very deep pipelines or pipelines in extremely congested rights-of-way installed in a configuration where liquid water is expected to accumulate.
- (e) Changes to compressor, meter, and regulator station facilities where there is limited space and access.

2.2 *Unnecessary.*

Examples of conditions that may make it unnecessary to design and construct features to reduce the risk of internal corrosion include the following.

- (a) The operator transports:
 - (1) Vaporized LNG where no other source of supply or interconnect exists. This gas is very dry

- and is extremely unlikely to produce internal corrosion.
- (2) Gas that meets the typical gas quality specification in NACE SP0106, Appendix A.
 - (3) Gas with a velocity such that impurities are kept suspended in the gas stream, minimizing the accumulation of corrosive liquid.
- (b) The operator uses:
- (1) Chemicals (e.g., corrosion inhibitors, biocides) to mitigate the occurrence of internal corrosion.
 - (2) Moisture analyzers or liquid water removal devices upstream of the pipeline segment to monitor for liquid water.
 - (3) Gas quality monitoring upstream, provided that short-term upsets would be detected and managed.
- (c) The operator installs:
- (1) In-kind replacement of pipe, valve, fitting, or other line components with no known internal corrosion with like size and like configuration. For example, replacement of a small section of 24-inch pipe with 24-inch pipe, or replacement of a full-port ball valve with a full-port ball valve.
 - (2) Additions to meter stations or regulating stations, such as an additional meter run or addition of a relief valve.
 - (3) Pipe with no inclination angles exceeding the critical angle. See NACE SP0206, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)."
 - (4) Pipeline for a temporary operating period of service not to exceed 5 years beyond installation, provided that the corrosion rate would not achieve a predicted failure pressure (PFP) below operating pressure in that time period.
 - (5) Pipeline in a normally dry gas system where short-term upsets would blend with a sufficient volume of dry gas to make the risk of internal corrosion negligible (e.g., buried below the frost line and away from large temperature differentials).
 - (6) Pipeline with no in-line pressure reducing devices that would precipitate the fall-out of liquid water into the pipe segment.

3 DESIGN CONSIDERATIONS

3.1 General.

- (a) The incorporation of design features to address internal corrosion improves the ability of the operator to prevent internal corrosion and to perform maintenance activities to control internal corrosion. There are many design features that an operator can incorporate to address the risk of internal corrosion. See guide material under §192.475.
- (b) To address the design requirements of reducing the risk of internal corrosion, an operator should address design features in the order of (1) configuration, (2) liquid removal, and then (3) monitoring.
- (c) If the configuration of the pipeline is such that the risk that liquid water will collect is nonexistent or minimal, the operator may not need to design for liquid water removal or monitoring.
- (d) If the configuration would allow liquid water to collect, the operator would be required to design for effective liquid water removal. Installation of these features would satisfy §192.476(a) requirements and monitoring would not be required, provided a program for liquid water removal is instituted. Examples where liquid water could accumulate include the following.
 - (1) Sags.
 - (2) Bases of inclines.
 - (3) Valves.
 - (4) Manifolds.
 - (5) Dead-legs.
 - (6) Traps.
- (e) Where liquid water is likely to collect, and the liquid water removal system is not provided or does not effectively remove liquid water and there is significant potential for internal corrosion, devices for monitoring are required (see §192.476(a)(2)).

3.2 Configuration design.

Examples of ways to reduce the risk that liquids will collect in a line include the following.

- (a) Minimize dead ends, such as pipe stubs downstream of stopple fittings, and low areas.
- (b) Minimize aerial crossings, since these can result in variation of temperature.
- (c) Design for turbulent flow, in which the velocity at a given point varies erratically in magnitude and direction, to decrease the chance of liquid water separating from the flow stream and accumulating.
- (d) Minimize the entry of water and corrosive gases at receipt locations. For example, liquid water removal devices (e.g., separators) at the inlet to compressor, meter, and regulator stations can protect station piping from the entry of liquid water.
- (e) Provide slam valves to isolate systems when corrosive gas is expected. A "slam valve" is a shut-off valve that stops the flow of gas in the event that a predetermined criteria is met.
- (f) Apply coatings to interior walls to inhibit internal corrosion.
- (g) Design for pigging.
- (h) Design for the injection of corrosion inhibitors.
- (i) Design with no inclination angles exceeding the critical angle at normal operating conditions (see NACE SP0206) so that liquid water will not accumulate, because the gas velocity will carry the liquid water through the pipeline.
- (j) On new pipelines with new receipt meters, design the configuration to accommodate equipment to monitor moisture and gas quality with control systems, such as slam valves or secondary liquid separation or dehydration equipment.
- (k) Maintain a flow velocity sufficient to prevent corrosive liquids from dropping out of the gas stream.
- (l) Evaluate the seasonal nature of delivery and capacity patterns and design to avoid no-flow or low-flow conditions.
- (m) Include equipment to evaluate gas quality characteristics (e.g., water, carbon dioxide, H₂S, oxygen).
- (n) Provide for blending, such that liquid water will be reabsorbed into the gas stream where there is potential for liquid water to enter the line during upset conditions.
- (o) See NACE SP0106, Sections 3, 5, and 7 for internal corrosion design considerations.

3.3 *Liquid removal.*

- (a) Install equipment to allow liquid water sampling at key areas, such as pig traps, isolated sections with no flow, dead ends, and river and road crossings.
- (b) Implement a pigging or sweeping program for cleaning of the pipeline so that if liquid water does collect for a short period of time, the liquid water can be removed through pigging or sweeping at necessary intervals. "Sweeping" is a process in which the gas stream has a velocity high enough to move liquids downstream to a collection point.
- (c) Install drips or other liquid water removal facilities along the pipeline where liquid water is expected to accumulate and implement a drip management program to blow drips and sample liquid water.
- (d) See NACE SP0106, Sections 3, 5, and 7 for internal corrosion control methods.

3.4 *Monitoring for internal corrosion.*

- (a) Identify critical low spots and instrument the pipeline to monitor relevant operating conditions (e.g., temperature, pressure, velocity, dew point) and implement a program to detect and manage short-term upsets.
- (b) Install direct corrosion monitoring at points on the pipeline with significant potential for internal corrosion and implement a program for scheduled monitoring and analysis. For monitoring guidelines, see NACE 3T199, "Techniques for Monitoring Corrosion and Related Parameters in Field Applications."
- (c) Implement a liquid water sampling and analysis program, and other indirect monitoring, to determine if there is a significant potential for internal corrosion. If liquid water is present in the system, analysis for CO₂, H₂S, bacteria (MIC), acids, and other corrosion constituents should be made. See NACE SP0106 and NACE 3T199 for monitoring guidelines.
- (d) Use in-line inspection (ILI) tools with a frequency based on corrosion rates and remaining wall thickness, similar to the requirements of an operator's IMP. See NACE SP0102, "In-Line Inspection of Pipelines," regarding design considerations for ILI.

- (e) See NACE SP0106, Sections 4, 6, and 7 for operating and maintenance of internal control systems.

4 CHANGE IN CONFIGURATION

- (a) The preamble to the initial regulation states that the "change in configuration" means changes in the physical features of a pipeline.
- (b) The following are examples of changes to configuration.
 - (1) A physical change that would compromise the effectiveness of liquid water removal features downstream, such as the following.
 - (i) Reversing flow.
 - (ii) Removal of drips, launchers, receivers, or associated piping, valves, or vessels.
 - (iii) Diameter changes.
 - (iv) Installation of sharp radius bends, or other changes that would make a piggable line no longer piggable.
 - (v) Bypassing drips, slug catchers, or filters.
 - (2) Adding potential sources of liquid water to the system that would change existing downstream monitoring locations.
 - (3) Abandonment or inactivation of a segment of pipeline.
 - (4) Changes that would affect existing downstream internal corrosion mitigation systems by changing volume or flow characteristics (e.g., extending the length of a pipeline, changing the diameter over a significant length).
 - (5) Changes of material (e.g., replacement of steel pipe with stainless steel pipe).
 - (6) Other physical changes that would indicate a change in monitoring or internal corrosion mitigation in downstream facilities.
- (c) If a configuration change occurs that increases the risk of internal corrosion, see 3.1 through 3.3.

5 RECORDS

5.1 *Design features.*

- (a) Documentation that the pipeline design features have addressed the impact of internal corrosion may be provided in the operator's project scope, design specifications, standards, or other documents deemed appropriate by the operator.
- (b) Documentation that construction of these design features may be provided in the as-built records, which show that the project scope, design specifications, standards, or other applicable documents were followed.
- (c) Records may be maintained electronically, as paper copies, or in any other appropriate format.

5.2 *Configuration.*

Where the operator has determined that the designed pipeline configuration is such that the risk of liquid water collecting is minimal (e.g., internal corrosion is unlikely to occur), the operator is required to document this determination and that the configuration was constructed as designed (see §192.476(d)). For example, if the pipeline diameter was designed so that the gas velocity is such that liquid water will not fall out of the gas stream, documents showing the determination that liquid water will not fall out and the designed pipe diameter was actually installed are necessary.

5.3 *Liquid removal features.*

Where the operator has determined that liquid water removal features are necessary, the operator will need to document this determination and that the features were installed (see §192.476(d)). For example, if the use of drips is determined to be necessary, the operator needs to document that determination and the related installation. The operator should document the location of each drip installed and the maintenance program for each drip.

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 <ul style="list-style-type: none"> • No buildings for human occupancy within 300 feet • With buildings for human occupancy within 300 feet 	1.10 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

1.3 Alternate Method

For conditions of low stress level, the following method may be used. An MAOP, not to exceed the established MAOP, may be determined by the following formula:

$$P = \frac{2St_rT}{D}$$

Where:

- P = MAOP (not to exceed established MAOP), psig
- S = Hoop stress, psig
- t_r = Actual remaining wall thickness at point of deepest corrosion, inches
- T = Temperature derating factor, see §192.115
- D = Nominal outside diameter (see Table 192.105i), inches

S must not exceed 72% SMYS in Class 1 locations, 60% in Class 2 locations, 50% in Class 3 locations, and 40% in Class 4 locations.

2 REPAIR OR REPLACEMENT

If a pipeline has an area of external corrosion that disqualifies it for service at the established MAOP, or if the MAOP cannot be reduced to the indicated safe level, it should be repaired or replaced. For acceptable methods of repair, see 3 below and §§192.703, 192.711(b), 192.713, and 192.717.

3 RELIABLE ENGINEERING TESTS AND ANALYSES (§192.485(a))

Reliable engineering tests and analyses demonstrate compliance with a performance standard. Operators may conduct their own tests and analyses; or, they may choose to accept testing and analyses done by manufacturers, trade associations, consultants, or other operators. The engineering tests and analyses should:

- (a) Include the following items, as needed, to achieve satisfactory precision.
 - (1) Concise and orderly procedures for conducting tests and analyses.
 - (2) Listing of equipment needed.
 - (3) Descriptions of test specimens.
 - (4) Required calculations.
- (b) Exhibit sound engineering practices, which may include the following.
 - (1) Knowledge and experience relating to the subject area.
 - (2) Data evaluation and statistical analysis.
 - (3) Assessment of test results to verify an analytical model.
 - (4) Application of scientific principles.

§192.487

Remedial measures: Distribution lines other than cast iron or ductile iron lines.

[Effective Date: 01/13/00]

(a) **General corrosion.** Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. 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.** Except for cast iron or ductile iron pipe, each segment of

distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

[Issued by Amdt. 192-4, 36 FR 12297, June 30, 1971; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]

GUIDE MATERIAL

1 Pitting

- (a) Where inspection indicates that localized corrosion pitting exists which may result in leakage, or indicates general corrosion exists that does not require replacement under §192.487(a), the operator should consider the following.
 - (1) Examining the corrosion history and leak records to see if the additional information from this review warrants replacing a segment of this distribution pipe instead of repair.
 - (2) Installing leak clamps over the pits or using other suitable repair methods that will permanently restore the serviceability of the pipeline.
- (b) In addition to repairs, the operator should consider the following.
 - (1) Cleaning and coating the exposed piping in accordance with §192.461.
 - (2) Applying or increasing the level of cathodic protection (CP).
 - (3) Installing test wires for monitoring CP.

2 RELIABLE ENGINEERING TESTS AND ANALYSES

See guide material under §192.485.

§192.489

Remedial measures: Cast iron and ductile iron pipelines.

[Effective Date: 08/01/71]

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

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

GUIDE MATERIAL

- (a) For cast iron pipe, see Guide Material Appendix G-192-18.
- (b) For ductile iron, see Guide Material Appendix G-192-18, Section 5.3.

§192.490

Direct assessment.

[Effective Date: 11/25/05]

Each operator that uses direct assessment as defined in §192.903 on an onshore transmission line made primarily of steel or iron to evaluate the effects of a threat in the first column must carry out the direct assessment according to the standard listed in the second column. These standards do not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

Threat	Standard ¹
External corrosion	§192.925 ²
Internal corrosion in pipelines that transport dry gas	§192.927
Stress corrosion cracking	§192.929
¹ For lines not subject to Subpart O of this part, the terms "covered segment" and "covered pipeline segment" in §§192.925, 192.927, and 192.929 refer to the pipeline segment on which direct assessment is performed. ² In §192.925(b), the provision regarding detection of coating damage applies only to pipelines subject to Subpart O of this part.	

[Issued by Amdt. 192-101, 70 FR 61571, Oct. 25, 2005]

GUIDE MATERIAL

Direct assessment is a process for managing the effects of external corrosion, internal corrosion, or stress corrosion cracking on pipelines made primarily of steel or iron. This process involves data collection, indirect inspection, direct examination, and evaluation. Operators may use direct assessment not only to find existing corrosion defects, but also to prevent future corrosion problems. See guide material under §§192.925, 192.927, and 192.929.

§192.491
Corrosion control records.
[Effective Date: 07/08/96]

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

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

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

[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]

GUIDE MATERIAL

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

- (a) Location of test stations.
- (b) Location of rectifiers and groundbeds.
- (c) Location of galvanic anodes.
- (d) Location of corrosion control facilities, such as insulating flanges or connections, bonds, automatic switches, and diodes.
- (e) Readings of pipe-to-soil potential.
- (f) Length and location of cathodically protected segments of piping.
- (g) Location of unprotected metallic piping.
- (h) Date cathodic protection facilities placed in service.

§192.493

In-line inspection of pipelines.

[Effective Date: 07/01/2020]

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

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

GUIDE MATERIAL

See Guide Material Appendix G-192-14 for information about in-line inspection of pipelines.

SUBPART J TEST REQUIREMENTS

<p>§192.501 Scope.</p> <p style="text-align: right;"><i>[Effective Date: 11/12/70]</i></p>
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This subpart prescribes minimum leak-test and strength-test requirements for pipelines.

GUIDE MATERIAL

All newly installed, replaced, or relocated transmission lines, distribution lines, Type A gathering lines, and Type B gathering lines (§192.9(c) and (d)), must be tested in accordance with Subpart J.

<p>§192.503 General requirements.</p> <p style="text-align: right;"><i>[Effective Date: 10/01/15]</i></p>

- (a) No person may operate a new segment of pipeline, or return to service a segment of pipeline that has been relocated or replaced, until —
 - (1) It has been tested in accordance with this subpart and §192.619 to substantiate the proposed maximum allowable operating pressure; and
 - (2) Each potentially hazardous leak has been located and eliminated.
- (b) The test medium must be liquid, air, natural gas, or inert gas that is —
 - (1) Compatible with the material of which the pipeline is constructed;
 - (2) Relatively free of sedimentary materials; and
 - (3) Except for natural gas, nonflammable.
- (c) Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the following maximum hoop stress limitations apply:

Class Location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

(d) Each joint used to tie in a test segment of pipeline is excepted from the specific test requirements of this subpart, but each non-welded joint must be leak tested at not less than its operating pressure.

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

- (1) The component was tested to at least the pressure required for the pipeline to which it is being added;
- (2) The component was manufactured under a quality control system that ensures that each

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

(3) The component carries a pressure rating established through applicable ASME/ANSI, 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.

3 HYDROSTATIC TEST

3.1 Test preparation.

It is recommended that the pipeline segment to be tested be physically isolated from all other pipelines. See 1(d) above. Testing against closed valves is not recommended. Weld caps, blind flanges, or other devices of appropriate design should be utilized to seal pipe ends. It is also recommended that spheres or squeegees be inserted in the pipeline ahead of the water to reduce air entrapment while filling and to facilitate dewatering operations.

3.2 Test evaluation.

(a) General.

In order that intelligent interpretation of pressure variations can be made, it is important that accurate thermometers, deadweight pressure gauges, meters, etc., be used and that the readings be taken at properly located points and at proper intervals of time. The use of a pressure-volume plot is recommended for tests that are planned to approach SMYS.

(b) Small changes in pressure during hold period.

Experience has shown that a small steady decline in pressure often occurs during the hold period. This does not necessarily indicate the existence of a leak. Such declines can often be caused by a change in temperature of the test liquid, a small entrapment of air, or a leaking gauge connection. A pressure rise is usually caused by the warming of air trapped in the structure or the warming of the test liquid or both. When an appreciable amount of pipe is exposed to atmosphere (not backfilled) during the test, temperature effects are sometimes quite pronounced.

In the event of a small steady pressure decline, it is considered good practice to periodically add liquid, thereby maintaining the desired pressure until the hold period is completed. Likewise, it is also considered good practice to bleed off small quantities of test liquid to prevent exceeding the maximum selected pressure.

3.3 Locating minor leaks.

When a hydrostatic strength proof test has been completed and there are indications of a minor leak which was not located during the test, the line may be filled with natural or other detectable gas at a pressure less than or equal to the maximum allowable operating pressure of the section of line being tested; and a suitable gas detection device (e.g., flame ionization analyzer, controlled catalytic combustion unit, infrared analyzer, or nitrous oxide detector) used to search for the leak.

3.4 Repairs.

Temporary repairs may be made in order not to interrupt the test, and a permanent repair made after completing the test and before placing the line in service. If permanent repairs are made after the conclusion of the test using pretested pipe, the tie-in welds must be inspected in accordance with §192.241.

4 AIR, INERT, OR NATURAL GAS TEST

Maximum hoop stress limitations are specified by §192.503(c). More stringent requirements for conducting such strength tests within 300 feet of buildings designed for human occupancy are specified by §192.505(a).

4.1 Test preparation.

(a) It is recommended that the pipeline segment to be tested be physically isolated from all other pipelines. See 1(d) above. Testing against closed valves is not recommended. Weld caps, blind flanges, or other devices of appropriate design should be utilized to seal pipe ends.

(b) Purging should be considered to prevent an explosive air-gas mixture in the test segment. Refer to §§192.629 and 192.751.

(c) In order that intelligent interpretation of pressure variations can be made, it is important that accurate

thermometers, deadweight pressure gauges, meters, etc. be used and that the readings be taken at properly located points and at proper intervals of time.

4.2 Test procedure.

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

4.3 Locating leaks.

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

4.4 Repairs.

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

5 RECORDS

See guide material under §192.517.

§192.506

Transmission lines: Spike hydrostatic pressure test.

[Effective Date: 07/01/2020]

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

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

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

- (1) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments;
- (2) Procedures and processes to conduct tests, examinations, assessments, perform evaluations, analyze defects, and remediate defects discovered;
- (3) Data requirements, including original design, maintenance and operating history, anomaly or flaw characterization;
- (4) Assessment techniques and acceptance criteria;

- (5) Remediation methods for assessment findings;
- (6) Spike hydrostatic pressure test monitoring and acceptance procedures, if used;
- (7) Procedures for remaining crack growth analysis and pipeline segment life analysis for the time interval for additional assessments, as required; and
- (8) Evidence of a review of all procedures and assessments by a qualified technical subject matter expert.

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

GUIDE MATERIAL

1 APPLICABILITY

- (a) Spike hydrostatic testing is referenced in §192.710(c)(3), 192.921(a)(3), and 192.937(c)(3), but no section of Part 192 requires that a spike hydrostatic test be performed for new or existing pipelines. It is an appropriate integrity assessment method for time-dependent threats such as the following.
 - (1) Stress corrosion cracking.
 - (2) Selective seam weld corrosion.
 - (3) Manufacturing and related defects, including defective pipe and pipe seams.
 - (4)) Other forms of defect or damage involving cracks or crack-like defects.
- (b) A spike hydrostatic pressure test typically either removes existing cracks that are detrimental by causing failure or proves the absence of crack defects that could affect the serviceability of a pipeline. The spike portion of the pressure test is designed to cause such marginal crack defects to fail during the early spike phase of the pressure test.
- (c) See Guide Material Appendix G-192-9A, Section 3.4.

2 RECORDS

See guide material under §192.517

§192.507

Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage.

[Effective Date: 03/12/21]

Except for service lines and plastic pipelines, each segment of a pipeline that is to be operated at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. (689 kPa) gage must be tested in accordance with the following:

- (a) The pipeline operator must use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested.
- (b) If, during the test, the segment is to be stressed to 20 percent or more of SMYS and natural gas, inert gas, or air is the test medium —
 - (1) A leak test must be made at a pressure between 100 p.s.i. (689 kPa) gage and the pressure required to produce a hoop stress of 20 percent of SMYS; or
 - (2) The line must be walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS.
- (c) The pressure must be maintained at or above the test pressure for at least 1 hour.
- (d) For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation hydrostatic pressure test must be conducted in accordance with the requirements of this section.

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

GUIDE MATERIAL

See 1(b), 1(c), 2, 3, and 4 of the guide material under §192.505; guide material under §§192.515 and 192.517; and Guide Material Appendices G-192-9, G-192-9A, and G-192-10.

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§192.509

Test requirements for pipelines to operate below 100 p.s.i. (689 kPa) gage.

[Effective Date: 07/13/98]

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

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

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

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

GUIDE MATERIAL

1 GENERAL

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

2 TEST DURATION

- (a) See 5(a) and (b) of the guide material under §192.513.
- (b) An example of an approach to determine the test durations for steel pipe at typical diameters and lengths is presented in Table 192.509i. These durations do not include the time to pressurize the test segments, time for temperature stabilization, or the time for depressurizing the test segments. The test period should begin when the pressure of the test medium stabilizes.
- (c) The time required to reach the test pressure and temperature stabilization depends on several factors, including pipe diameter, pipe length, whether the pipe segment is buried or exposed to the atmosphere, and the initial temperatures of the test segment, pressurizing medium, and the environment around the test segment.
- (d) Temperature variations during the test period could affect the gauge pressure and should be considered.

Example Leak Test Duration for Steel Pipe (hours)							
Nominal Pipe Size	2	3	4	6	8	10	12
Schedule	40	40	40	40	40	40	40
ID (in.)	2.067	3.068	4.026	6.065	7.981	10.020	11.938
Length (ft.)							
50	1/4	1/4	1/4	1/2	1/2	3/4	1 1/4
100	1/4	1/4	1/4	3/4	1	1 1/2	2 1/4
200	1/4	1/2	1/2	1 1/4	2	3	4 1/4
300	1/4	1/2	3/4	1 3/4	3	4 1/2	6 1/2
400	1/2	3/4	1	2 1/4	4	6	8 1/2
500	1/2	3/4	1 1/4	2 3/4	4 3/4	7 1/2	10 3/4
1000	3/4	1 1/2	2 1/2	5 1/2	9 1/2	15	21 1/4

Notes:

1. See 5(d) and (e) of the guide material under §192.513 for an explanation of the calculations used to prepare this table.
2. The detectable pressure drop and detectable leak rate criteria should be based on the operator's design and experience. For this example, the detectable leak rate (RL) = 5.0 scf/hr and the detectable pressure drop (Pd) = 2 psi.
3. Note that a change in schedule number or wall thickness might affect the calculated duration.
4. Minimum test duration is chosen to be 1/4 hour, and calculated test durations have been rounded up in 1/4-hour increments.
5. For test durations beyond 24 hours, consider testing shorter sections to reduce the test duration.
6. See Guide Material Appendix G-192-9.

TABLE 192.509i

<p>§192.511</p> <p>Test requirements for service lines.</p> <p><i>[Effective Date: 07/13/98]</i></p>
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(a) Each segment of a service line (other than plastic) must be leak tested in accordance with this section before being placed in service. If feasible, the service line connection to the main must be included in the test; if not feasible, it must be given a leakage test at the operating pressure when placed in service.

(b) Each segment of a service line (other than plastic) intended to be operated at a pressure of at least 1 p.s.i. (69 kPa) gage but not more than 40 p.s.i. (276 kPa) gage must be given a leak test at a pressure of not less than 50 p.s.i. (345 kPa) gage.

(c) Each segment of a service line (other than plastic) intended to be operated at pressures of more than 40 p.s.i. (276 kPa) gage must be tested to at least 90 p.s.i. (621 kPa) gage, except that each segment of a steel service line stressed to 20 percent or more of SMYS must be tested in accordance

with §192.507 of this subpart.

[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]

GUIDE MATERIAL

See 1(b), 3.1, and 4 of the guide material under §192.505; guide material under §§192.509, 192.515 and 192.517; and Guide Material Appendix G-192-10.

§192.513

Test requirements for plastic pipelines.

[Effective Date: 01/22/19]

- (a) Each segment of a plastic pipeline must be tested in accordance with this section.
- (b) The test procedure must insure discovery of all potentially hazardous leaks in the segment being tested.
- (c) The test pressure must be at least 150% of the maximum operating pressure or 50 p.s.i. (345 kPa) gage, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test.
- (d) During the test, the temperature of thermoplastic material may not be more than 100 °F (38 °C), or the temperature at which the material's long-term hydrostatic strength has been determined under the listed specification, whichever is greater.

[Amdt. 192-77, 61 FR 27789, June 3, 1996 with Amdt. 192-77 Correction, 61 FR 45905, Aug. 30, 1996;
Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt 192-124, 83 FR 58694, Nov. 20, 2018]

GUIDE MATERIAL

1 JOINTS

The joints in the plastic piping should be set, cured, or hardened before the test is initiated.

2 ODORANT

Odorant in the liquid form may be detrimental to certain kinds of plastic and should not be used to locate leaks in plastic pipelines.

3 TEMPERATURE LIMITATIONS

The operator should ensure that piping being tested does not exceed the maximum temperature at which it has been qualified as indicated by the marking on the pipe and fittings. The operator should consider the influence of ambient, test medium, and ground temperatures that can affect the pipe temperature during a test. Sunlight may significantly elevate the pipe temperature, and black plastic pipe can exceed 140 °F (60 °C) temperature when exposed to direct sunlight. Some methods used to control or reduce temperatures during testing are as follows.

- (a) Spraying the piping with water.

- (b) Protecting the piping from direct sunlight.
- (c) Placing the piping in the ditch to shade the piping.
- (d) Performing the pressure test during the cooler parts of the day.

When addressing the requirements of §192.513(d), see guide material under §192.63 and Guide Material Appendix G-192-9A, Section 4.4.

4 TEST PRESSURE LIMITATIONS FOR PIPELINES USING 0.4 DESIGN FACTOR

To prevent failures during pressure testing, the maximum pressure should not exceed 2.0 times the design pressure of the pipe calculated in accordance with §192.121 using the pipe material HDB adjusted for average pipe wall temperatures during the test. If the intended or actual test pressure exceeds 2.0 times the design pressure, consult with the pipe manufacturer.

5 TEST DURATION

- (a) Establishing a test duration to determine potentially hazardous leaks in the segment being tested is based on analysis of multiple parameters, which include the following.
 - (1) Test medium used.
 - (2) Thermal effects.
 - (3) Volume of the test segment.
 - (4) Test pressure.
 - (5) Leak criteria.
 - (6) Instrumentation.
- (b) When an analysis is performed, sufficient test durations can be established for various diameters of pipe at various lengths.
- (c) If an analysis on the above parameters is not performed, examples of an approach to determine test durations for plastic service lines and mains at typical diameters and lengths are shown in Tables 192.513i and 192.513ii, respectively. These durations do not include the time to pressurize the test segments, time for temperature stabilization, and time for depressurizing the test segments. The test period should begin when the pressure of the test medium stabilizes.

Notes:

- (1) The stabilization period depends on several factors, such as pipe diameter, pipe length, and temperature variation. Due to the circumferential expansion of plastic pipe when subjected to the initial pressurization and temperature variations, it is common for the pressure to drop by a few psig until it reaches a steady state.
- (2) Temperature variations during the testing period could affect the gauge pressure and should be considered.
- (d) The formula used in the Tables below is a generalization of Boyle's gas law and is the basis for some operators' test durations.

$$\text{Test Duration (hours)} = [(3.71 \times 10^{-4}) \times d^2 \times L \times P_d] \div R_L$$

Where:

- d = Internal diameter, inches
- L = Length of test section, feet
- P_d = Pressure drop, psi
- R_L = Leak rate, scf/hr

- (e) In order to calculate the test duration, a pressure drop and leak rate criterion should be based on the operator's design and experience. The following ranges are examples.
 - (1) Detectable pressure drop (P_d): 1 - 5 psi.
 - (2) Detectable leak rate (R_L): 1 - 5 scf/hr.
- (f) When testing pipe of different sizes, the total test duration may be calculated by adding the test times

given in Table 192.513ii. As an example, when testing 2000 feet of 4-inch and 1000 feet of 2-inch pipe together, the total test duration would be 4 hours for the 4-inch and $\frac{3}{4}$ hour for the 2-inch pipe for a total of $4\frac{3}{4}$ hours.

Example Test Duration For Plastic Service Lines (minutes)				
Criterion: Leak rate (R_L) = 1.5 scf/hr and pressure drop (P_d) = 2 psi (Minimum test duration is chosen to be 5 minutes)				
Pipe Size	½ CTS	1 CTS	1¼ CTS	IPS 1¼
Wall Thickness (in.)	0.090	0.099	0.121	-
SDR	-	-	-	10
Pipe Size ID (in.)	0.44	0.91	1.12	1.34
Length (ft.)				
50	5	5	5	5
100	5	5	5	10
200	5	5	10	15
300	5	10	15	20
400	5	10	15	25
500	5	15	20	30
<p>Formula: Test Duration (minutes) = $[(3.71 \times 10^{-4}) \times d^2 \times L \times (2)] \times 60 \div (1.5)$ $= 2.97 \times 10^{-2} (d^2)(L)$</p> <p>Where: d = Internal diameter, inches L = Length of test section, feet</p> <p><u>Notes:</u></p> <ol style="list-style-type: none"> 1. The pressure drop and leak rate criteria should be based on the operator's design and experience. 2. Calculated test durations have been rounded up in 5-minute increments. 				

TABLE 192.513i

Example Test Duration For Plastic Mains (hours)					
Criteria: leak rate (R_L) = 5.0 scf/hr and pressure drop (P_d) = 2 psi (Minimum test duration is chosen to be ¼ hour)					
Pipe Size	IPS 2	IPS 3	IPS 4	IPS 6	IPS 8
SDR	11	11	11	11	11
Pipe Size ID (in.)	1.93	2.84	3.65	5.37	6.99
Length (ft.)					
50	1/4	1/4	1/4	1/4	1/2
100	1/4	1/4	1/4	1/2	3/4
200	1/4	1/4	1/2	1	1 1/2
300	1/4	1/2	3/4	1 1/2	2 1/4
400	1/4	1/2	1	1 3/4	3
500	1/2	3/4	1	2 1/4	3 3/4
1000	3/4	1 1/4	2	4 1/2	7 3/4
2000	1 1/4	2 1/2	4	8 3/4	14 1/2
3000	1 3/4	3 3/4	6	13	21 3/4
<p>Formula: Test Duration (hours) = $[(3.71 \times 10^{-4}) \times d^2 \times L \times (2)] \div (5)$ $= 1.48 \times 10^{-4} (d^2)(L)$</p> <p>Where: d = Internal diameter, inches L = Length of test section, feet</p> <p><u>Notes:</u></p> <ol style="list-style-type: none"> The pressure drop and leak rate criteria should be based on the operator's design and experience. Calculated test durations have been rounded up in ¼-hour increments. For test durations beyond 24 hours, consider testing shorter sections to reduce test duration. 					

TABLE 192.513ii

6 SAFETY CONSIDERATIONS

See guide material under §192.515.

7 OTHER

See 2 and 4 of the guide material under §192.505; guide material under §§192.515 and 192.517; and Guide Material Appendices G-192-9, G-192-9A, and G-192-10.

§192.515

Environmental protection and safety requirements.

[Effective Date: 11/12/70]

(a) In conducting tests under this subpart, each operator shall insure that every reasonable precaution is taken to protect its employees and the general public during the testing. Whenever the hoop stress of the segment of the pipeline being tested will exceed 50 percent of SMYS, the operator shall take all practicable steps to keep persons not working on the testing operation outside of the testing area until the pressure is reduced to or below the proposed maximum allowable operating pressure.

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

GUIDE MATERIAL

1 GENERAL

See 3.1 and 4.1 of the guide material under §192.505.

2 SAFETY CONSIDERATIONS

2.1 General.

The following are other factors to be considered in the interest of safety.

- (a) Locating personnel operating testing equipment at a safe distance from the pipeline facilities under test.
- (b) Visually inspecting temporary piping, closures, and other equipment used in connection with the test, both prior to the application of the test pressure and at appropriate intervals during the test, to ensure soundness.
- (c) Providing for supports or anchors, as required, to prevent excessive stress levels in the test piping and the piping under test.
- (d) Locating blowdown devices in a manner that will divert the gas and the test medium away from electrical conductors.
- (e) Filling and purging the facilities in a manner consistent with good purging principles, taking into consideration the following.
 - (1) Compliance with the requirements in §192.629.
 - (2) Minimizing entrapment of air or gas in the pipeline segment to be subjected to hydrostatic test by inserting a sphere or other suitable device ahead of the test medium while filling, or by installing vents at high spots.
 - (3) Wind direction and velocity.
 - (4) Prevention of accidental ignition. See §192.751.
- (f) Communications between the supervisor in charge and the line surveillance teams, pressure control and monitor stations, blowdown points and other stations or personnel responsible for various aspects of the work.
- (g) Ready availability of fire extinguishers, breathing apparatus, safety harnesses, ear protection devices, combustible gas detectors, oxygen deficiency indicators and other such equipment in the work area.
- (h) Distribution of a written test procedure (including the applicable portions of Guide Material Appendix G-192-12) to employees or contractor personnel or both. The procedure should be reviewed with all persons involved in conducting the test prior to commencing any work and should include actions to be taken in the event of a test failure.

2.2 Tests in excess of 50 percent SMYS.

When the test will result in hoop stresses in excess of 50% SMYS, particularly in uprating facilities, each operator should consider the following precautionary measures to ensure that the test area is kept clear of persons not directly engaged in the testing operation.

- (a) Placing caution signs or barriers along the pipeline route wherever deemed appropriate, such as at roads and public corridors. These should be supplemented by security patrols or guards or both in residential areas, industrial areas and at river crossings.
- (b) Aerial surveillance of the pipeline route, when practical, to monitor activity in the test area when testing with natural gas, inert gas or air.
- (c) Notifying parties located in the general vicinity of the pipeline to avoid the test area during the period of the test.
- (d) Notifying law enforcement agencies, fire departments, state and county highway departments, railroad and utility companies with facilities in the test area and, as applicable, airport operators regarding the scope and period of the test.
- (e) When the test is being conducted in high exposure areas, consideration should be given to the following.
 - (1) Scheduling the test at a time to minimize public exposure.
 - (2) Limiting the length of the test section to minimize potential hazards.

2.3 Tests in excess of 90 percent SMYS.

When the test pressure will produce a hoop stress in excess of 90% of SMYS, the following additional precautions may be considered to minimize the risk to occupants of buildings in close proximity to the pipeline.

- (a) Using pre-tested pipe.
- (b) Pre-testing the segment.
- (c) Using energy absorbing devices (e.g., sandbag barriers, backfill, piling, and walls).

3 HAZARDS ASSOCIATED WITH FILLING AND DEWATERING PIPELINES FOR HYDROSTATIC TESTING

- (a) During the filling and dewatering processes, significant and sudden variations in pressure may occur within the pipeline and the temporary filling and dewatering piping. These variations can be caused by changes in velocity of the pig passing through bends in the pipeline or of the pig and water due to changes in pipeline elevation. Compressed air escaping around a pig can also create a source for stored energy within the pipeline. The release of this stored energy, as well as surges transferred from the pipeline to the temporary filling and dewatering piping, can result in pipe movement.
- (b) When conducting a hydrostatic test, the following should be considered when filling and dewatering pipelines.
 - (1) Prepare a detailed test plan that includes the required equipment, test duration, and test pressure.
 - (2) Conduct training for the individuals involved with the test that includes a review of the test and dewatering plan, instructions on the filling/dewatering system installation and techniques, and proper coupling and anchoring methods.
 - (3) Perform an engineering analysis of the existing and temporary piping systems to identify the forces that could adversely affect the integrity of the pipeline, the integrity of temporary fill piping, or the integrity and stability of the drainage components, such as excessive or variable pressures caused by a stuck pig or leaks. An engineering analysis may consist of the following.
 - (i) Designing the temporary piping system within the parameters of the hydrostatic pressure test. Consider factors such as the diameter and pressure rating of the temporary piping system (including couplings and fittings), the joining method, and the piping geometry.

- (ii) Accounting for hydrostatic head pressure caused by changes in elevation.
 - (iii) Considering pressure variations or thrust due to changes in direction at bends, elbows, and dead-ends.
 - (iv) Determining the proper joining method for the temporary piping system.
- (4) Develop installation techniques that address forces expected during the filling, testing, and dewatering operations. Those techniques would include effective anchoring systems that prevent pipe movement, separation, or whipping. Piping components (e.g., couplings, flanges, valves) should be free of damage and installed in accordance with manufacturer's instructions.
- (5) Inspect temporary pipe, couplings, and fittings to ensure they are in good condition and rated for the pressure and temperature conditions specified for the test.
- (6) Ensure that anchoring and support systems are installed in accordance with the plan.
- (7) Control access to the area around the test site by establishing a limited-access zone to keep out persons not involved with the test.
- (c) For additional background information on this subject, see OPS Advisory Bulletin ADB-04-01 (69 FR 58225, Sept. 29, 2004; reference Guide Material Appendix G-192-1, Section 2).

4 ENVIRONMENTAL CONSIDERATIONS

Each operator, in fulfilling the local, state, and federal environmental regulations with respect to the disposal of the test medium, should, among other things, give consideration to the following.

- (a) Selecting water from satisfactory sources.
- (b) Mitigating erosion and flooding of the area where the water is being discharged.
- (c) Using filters, impoundment facilities or other appropriate methods to ensure that the atmosphere and the surface waters are not unnecessarily contaminated by the products being discharged.
- (d) Using silencers, during the blowdown operation, where sound might be generated which is objectionable to area residents.
- (e) Scheduling and locating the blowdown to minimize public objection to the noise generated.

§192.517

Records.

[Effective Date: 07/01/2020]

(a) Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§192.505, 192.506 and 192.507. The record must contain at least the following information:

- (1) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.
- (2) Test medium used.
- (3) Test pressure.
- (4) Test duration.
- (5) Pressure recording charts, or other record of pressure readings.
- (6) Elevation variations, whenever significant for the particular test.
- (7) Leaks and failures noted and their disposition.

(b) Each operator must maintain a record of each test required by §§192.509, 192.511, and 192.513 for at least 5 years.

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

GUIDE MATERIAL

(a) In addition to the requirements of §192.517(a), records of a pressure test should include the following.

- (1) Start and completion times of the test.
 - (2) Name of the person responsible for performing the test and the person who approved the test, if different.
 - (3) A detailed description of the segment of pipeline and associated components that were tested, which should include:
 - (i) For station piping, a diagram of the station that identifies the location of the tested segment;
 - (ii) For a pipeline, the segment length using mile markers, stationing, or other location description;
 - (iii) For pipeline components, the type, size, locations, and pressure ratings; and
 - (iv) For all tested pipe, the following.
 - (A) Outside diameter.
 - (B) Wall thickness.
 - (C) Pipe grade or designation.
 - (D) Pipe material.
 - (E) Joint types.
 - (F) Seam type.
- (b) Records of a successful hydrostatic pressure test might include the following in addition to that listed under (a) above.
- (1) Minimum and maximum elevation values, including the calculated test pressure, measured test pressure, or both at the control point as well as the highest and lowest points.
 - (2) Temperatures recorded throughout the duration of the test.
 - (i) Ambient air.
 - (ii) Underground (restrained) piping.
 - (iii) Aboveground (unrestrained) piping.
 - (3) Liquid volume injected, withdrawn, or both, during the test.
 - (4) Pressure versus volume plot.

Note: To confirm that the test did not reveal any leaks or yield the pipe, taking into consideration the thermal effects on unrestrained piping throughout the duration of the test.
- (c) For pre-November 12, 1970 pipelines, operators might not have pressure test records that meet all of the current requirements under §192.517(a). In the event a pressure test was conducted prior to that date, an operator may consider several different types of records that verify a pressure test was conducted. Preferably, those records would include a date and signature of the individual who witnessed the test. Any one or combination of the following records may be considered.
- (1) Test pressure records, including charts or other forms indicating pressure recordings.
 - (2) Job-specific pressure test plan and procedure.
 - (3) Notation of completion of pressure test requirements on as-built drawings.
 - (4) Field notes or log books with details of testing.
 - (5) An operator form with details of the pressure test.
 - (6) Other documents that the operator deems appropriate per their specific standards.
- (d) In addition to the requirements of §192.517(a), records of a spike hydrostatic test conducted under §192.506(a) should include the following.
- (1) Start and end times of the spike portion of the pressure test.
 - (2) The spike pressure throughout the duration of this portion of the pressure test.
 - (3) Whether the spike pressure was equal to or greater than 100% SMYS or 1.5 times the MAOP.
 - (4) Pressure versus volume plot, if performed, to confirm that the test did not reveal any leaks or yield the pipe.
- (e) For tests conducted under §§192.509, 192.511, or 192.513, records are required to show that the tests have been conducted. The date, location of the test, and the test pressure applied might be sufficient documentation. Additional information may be included at the discretion of the operator.
- (f) For segments of steel service line stressed to 20% or more of SMYS (§192.511(c)), records are required

to document testing in accordance with §192.507.

- (g) For a non-welded joint used to tie in a pipeline, the operator should have a record demonstrating that a leak test was performed at not less than the operating pressure (see §192.503(d)).

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SUBPART L OPERATIONS

§192.601

Scope.

[Effective Date: 11/12/70]

This subpart prescribes minimum requirements for the operation of pipeline facilities.

GUIDE MATERIAL

No guide material necessary.

§192.603

General provisions.

[Effective Date: 10/25/13]

(a) No person may operate a segment of pipeline unless it is operated in accordance with this subpart.

(b) Each operator shall keep records necessary to administer the procedures established under §192.605.

(c) The Associate Administrator or the State Agency that has submitted a current certification under the pipeline safety laws, (49 U.S.C. 60101 et seq.) with respect to the pipeline facility governed by an operator's plans and procedures may, after notice and opportunity for hearing as provided in 49 CFR 190.206 or the relevant State procedures, require the operator to amend its plans and procedures as necessary to provide a reasonable level of safety.

[Amdt. 192-27A, 41 FR 47252, Oct. 28, 1976; Amdt. 192-66, 56 FR 31087, Jul. 9, 1991; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt. 192-118, 78 FR 58897, Sept. 25, 2013]

GUIDE MATERIAL

Note: Although not required, operators of Type B gathering lines should consider establishing their own record retention procedures.

(a) Operators may use any recordkeeping method that produces authentic records. The data constituting these records should be retained in a medium that has a life expectancy at least equal to the specified retention period.

(b) Additional records might be required by state or other federal regulatory agencies.

(c) See guide material under §192.605. Also see Guide Material Appendix G-192-17 for summary of records required by Part 192.

§192.605

Procedural manual for operations, maintenance, and emergencies.

[Effective Date: 02/01/10]

(a) *General.* Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.

(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and subpart M of this part.

(2) Controlling corrosion in accordance with the operations and maintenance requirements of subpart I of this part.

(3) Making construction records, maps, and operating history available to appropriate operating personnel.

(4) Gathering of data needed for reporting incidents under Part 191 of this chapter in a timely and effective manner.

(5) Starting up and shutting down any part of the pipeline in a manner designed to assure operations within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices.

(6) Maintaining compressor stations, including provisions for isolating units or sections of pipe and for purging before returning to service.

(7) Starting, operating and shutting down gas compressor units.

(8) Periodically reviewing the work done by operator personnel to determine the effectiveness, and adequacy of the procedures used in normal operation and maintenance and modifying the procedures when deficiencies are found.

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

(10) Systematic and routine testing and inspection of pipe-type or bottle-type holders including-

(i) Provision for detecting external corrosion before the strength of the container has been impaired;

(ii) Periodic sampling and testing of gas in storage to determine the dew point of vapors contained in the stored gas which, if condensed, might cause internal corrosion or interfere with the safe operation of the storage plant; and

(iii) Periodic inspection and testing of pressure limiting equipment to determine that it is in safe operating condition and has adequate capacity.

(11) Responding promptly to a report of a gas odor inside or near a building, unless the operator's emergency procedures under §192.615(a)(3) specifically apply to these reports.

(12) Implementing the applicable control room management procedures required by §192.631.

(c) *Abnormal operation.* For transmission lines, the manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

- (i) Unintended closure of valves or shutdowns;
 - (ii) Increase or decrease in pressure or flow rate outside normal operating limits;
 - (iii) Loss of communications;
 - (iv) Operation of any safety device; and
 - (v) Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to persons or property.
- (2) Checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation.
- (3) Notifying responsible operator personnel when notice of an abnormal operation is received.
- (4) Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found.
- (5) The requirements of this paragraph (c) do not apply to natural gas distribution operators that are operating transmission lines in connection with their distribution system.
- (d) *Safety-related condition reports.* The manual required by paragraph (a) of this section must include instructions enabling personnel who perform operation and maintenance activities to recognize conditions that potentially may be safety-related conditions that are subject to the reporting requirements of §191.23 of this subchapter.
- (e) *Surveillance, emergency response, and accident investigation.* The procedures required by §§192.613(a), 192.615, and 192.617 must be included in the manual required by paragraph (a) of this section.

[Amdt. 192-27A, 41 FR 47252, Oct. 28, 1976; Amdt. 192-59, 53 FR 24942, July 1, 1988 with Amdt. 192-59 Correction, 53 FR 26560, July 13, 1988; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994 with Amdt. 19271A, 60 FR 14379, Mar. 17, 1995; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-112, 74 FR 63310, Dec. 3, 2009]

GUIDE MATERIAL

Note: Although not required, operators should consider establishing a procedural manual for Type B gathering lines.

1 GENERAL

- (a) Each procedural manual for operations, maintenance, and emergencies should include a written statement, procedure, or other document addressing each specific requirement of §192.605 that applies to the operator's pipelines. The requirements of §192.605 are included in paragraphs that cover the following topics.
- (1) General items related to the procedural manual (§192.605(a)).
 - (2) Maintenance and normal operation of any pipeline; §192.605(b)).
 - (3) Abnormal operation of transmission lines, other than those transmission lines operated by distribution operators in connection with their distribution system (§192.605(c)).
 - (4) Safety-related condition reports (§192.605(d)).
 - (5) Surveillance, emergency response, and accident investigation (§192.605(e)).
- The guide material under this section addresses most of the requirements of §192.605.
- (b) The comprehensive manual can consist of multiple binders with relevant sections kept at appropriate locations. Appropriate sections of other documents may be referenced instead of being incorporated, but the referenced documents are to be present at the location to which they apply.
- (c) The manual will necessarily vary in length and complexity depending upon the individual operator, its size, locale, policies, and types of equipment in use and the amount of material included in its entirety or cross-referenced, including manufacturers' instructions, where appropriate.
- (d) Procedures for only those facilities within the operator's system need be included in the manual.

Therefore, it is not necessary to have a manual for each pipeline.

- (e) The required review of the manual should ensure that the operator's current facilities and any deficiencies in the manual are addressed. An operator should consider reviewing its operator qualification (OQ) processes and procedures since changes to the manual may affect the OQ program. More serious deficiencies, possibly identified following an accident, may require immediate correction.
- (f) Many sections of the pipeline safety regulations are written using performance language to achieve a desired result, but the method to reach that result is not specified. In such situations, an operator should use a method that is suitable for its individual operations and include it in the manual.
- (g) An operator may include material in its procedural manual for operations, maintenance, and emergencies that is not required by the federal or state pipeline safety regulations (e.g., procedures for the use of personal protection equipment, procedures regarding the aesthetic acceptability of paint on aboveground piping). Even though such procedures themselves are supplementary to the procedures required by the pipeline safety regulations, they may be subject to inspection or enforcement by pipeline safety inspection agencies. The operator may consider identifying such procedures as not being part of the manual for operations, maintenance, and emergencies that is required by §192.605.
- (h) An operator may define in its manual a process to address situations in which a procedure cannot be followed in its entirety. That process should include the requirement for a written request and approval for a variance from the procedure, the level of authority that can approve a variance, and record-retention requirements. The operator should ensure the effect of the approved variance from the procedure still meets the minimum regulatory requirements.
- (j) See guide material under §192.491, 192.603, 192.709, and Guide Material Appendix G-192-17 for additional information on record retention and security.

2 MAINTENANCE AND NORMAL OPERATIONS

In addition to those items required to be in the manual under Subparts L and M as they apply to the operator's facilities, other Subparts (e.g., E, F, I, J, and K) may also require written procedures. Additional guide material can be found under individual sections.

2.1 *Control of corrosion.*

Refer to guide material for respective sections of Subpart I.

2.2 *Availability of construction records, maps, and operating history.*

- (a) Construction records, maps, and operating history should be comprehensive and current. The construction records, maps, and operating history will depend upon the individual operator, its size and locale, and the types of equipment in use. See guide material under §192.227 for records demonstrating the qualification of each individual welder at the time of construction.
- (b) The construction records, maps, and operating history should be made available to operating personnel, especially supervisors or those called on to safely operate pipeline facilities or respond to emergencies, or both. Dispatch or gas control personnel should have maps and operating history available.
- (c) For transmission and regulated gathering facilities, the types of records and data that could be made available are as follows.
 - (1) Pipeline system maps, including abandoned and out-of-service facilities.
 - (2) Compressor station and other piping drawings (mechanical and major gas piping).
 - (3) Maximum allowable operating pressures.
 - (4) Inventories of pipe and equipment.
 - (5) Pressure and temperature histories.
 - (6) Maintenance history.
 - (7) Emergency shutdown systems drawings.
 - (8) Isolation drawings.
 - (9) Purging information.
 - (10) Applicable bolt torquing information.

- (11) Operating parameters for engines and equipment.
- (12) Leak history.
- (d) For distribution systems, the types of records and data that could be made available are as follows.

- (1) Maps showing location of pipe, valves, and other system components.
 - (2) Maps and records showing pipe specifications, valve type, and operating pressure.
 - (3) Auxiliary maps and records showing other useful information, including abandoned and out-of-service facilities.
- (e) Communications with knowledgeable personnel should be maintained to respond to questions concerning the records, maps, or history if the need arises.
- (f) Field identification of valves.
- (1) Valve identification criteria should be established.
 - (2) Each operator should have available sufficiently accurate records (including field location measurements) to readily locate valves and valve covers.
 - (3) Where valves are located in a valve cluster or in close proximity to valves of other operators, in addition to records and field location measurements, the following are also recommended.
 - (i) A valve identification system should be developed so that each valve will have a unique set of numbers or letters, or both, which is keyed to the records or mapping system.
 - (ii) For above ground and vault applications, a readily observable and durable code identifying tag, stamp, or other device should be affixed to the valve.
 - (iii) For remotely operated and underground valves, a readily observable and durable code identifying tag, stamp or other device should be affixed to the inside wall of the valve box or valve extension unit. It should be affixed so that it will not interfere with the valve operation, and will not be defaced or dislocated by normal operations.
- (g) Regulator station drawings should show control line and pressure sensor location as needed. These drawings must be available to personnel working at the station (§192.605(b)(3)) and should be reviewed for accuracy prior to any work. Any changes resulting from work performed at a regulator station should be identified and noted on drawings.

2.3 *Data gathering for incidents.*

- (a) The operator should designate personnel to gather data at the incident site and other locations where records are retained.
- (b) For verification and telephonic reporting that an incident has occurred on the operator's facility, the following information should be gathered as soon as practicable. See Guide Material Appendix G-191-1 and guide material under §191.5.
 - (1) Time and date of the incident.
 - (2) Location and facilities involved.
 - (3) Number of fatalities and personal injuries necessitating in-patient hospitalization.
 - (4) Estimates of property damage and gas lost. See guide material under §191.3 and Guide Material Appendix G-191-5.
 - (5) Type of incident: leak, rupture, other.
 - (6) Whether there was an explosion.
 - (7) Whether there was a fire.
 - (8) Whether there was a curtailment or interruption of service.
 - (9) Environmental impact.
 - (10) Apparent cause and responsible party if known.
 - (11) Component(s) involved and material specification.
 - (12) Pressure at the time of incident.
 - (13) Estimated time of repair and return to service.
 - (14) A 24-hour staffed telephone number.
- (c) Procedures should be established for personnel to determine if the event meets the criteria for the Part 191 definition of an "incident" and to make the telephonic report. Alternate personnel should be included in the procedures in case primary personnel are not available. If some of the information is not available, the notification should be made without that information. Any corrections or additional information may be provided later. See guide material under §191.5.
- (d) For post-accident drug and alcohol testing, see Part 199 – Drug and Alcohol Testing and OPS Advisory Bulletin ADB-2012-02 (77 FR 10666, Feb. 23, 2012; see Guide Material Appendix G-192-1, Section 2).
- (e) For the written Incident Report, see guide material under §192.617 and Guide Material Appendices G-191-2 and G-191-5.

2.4 *Starting up and shutting down a pipeline.*

(a) Starting up any of the following: a newly constructed transmission line, regulated gathering line, distribution main, or another modified pipeline (e.g., an existing transmission line that has a new pressure gradient because of flow reversal, pipeline that has been converted to gas service under §192.14.

(1) For transmission lines, following the test to establish maximum allowable operating pressure (MAOP), the operator and the person in charge of placing the pipeline in service should establish procedures for commissioning the new or modified pipeline and placing it in service. The procedures should include provisions for the following.

- (i) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new or modified pipeline.
- (ii) Inspecting the overpressure protection devices required for starting up a new or modified pipeline, including the testing of set pressures and the checking of capacities, if necessary.
- (iii) Determining requirements for purging and notifying public officials. See guide material under §192.751.
- (iv) Establishing communication with field personnel and gas control personnel.
- (v) Controlling the purge flow rate when pressurizing the pipeline and monitoring pressures until normal operation is established.
- (vi) Conducting a follow-up leak survey, if applicable.
- (vii) Updating maps and other pertinent operating records.

(2) For distribution mains, following the test to prove tightness or strength, the operator should establish procedures for commissioning a new main. The procedures should include provisions for the following.

- (i) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new main.
- (ii) Tying-in the new system segment.
- (iii) Determining requirements for purging and notifying public officials and residents of purging activity. See guide material under §192.751.
- (iv) Updating maps and other pertinent operating records.
- (v) Inspecting the overpressure protection devices required for starting up a new or modified pipeline, including the verification of set pressures and the checking of capacities, if necessary.

(b) Starting up or reinstating service lines.

The operator should establish procedures for reinstating the service line following the test to prove tightness or strength. The procedures should include provisions for the following.

- (1) Ensuring that the procedural manual for operations, maintenance, and emergencies addresses the new or reinstated services.
- (2) Tying-in new or reinstated service segment.
- (3) Introducing gas into the meter. Also, see 2.4(c) below.
- (4) Updating maps or other pertinent operating records.
- (5) Preventing unauthorized turn-on.
- (6) For service lines that have individual pressure controls, such as farm taps, inspecting the overpressure protection devices required for starting up a new or modified pipeline, including the verification of set pressures and the checking of capacities, if necessary.

(c) Starting up service to a new customer.

The operator should establish procedures for starting up service to a new customer. The procedures should include provisions for the following.

- (1) Operating the meter or service-line valve.
- (2) Checking the regulator, if present, and the customer meter.
- (3) Where a closed valve is not used at the meter outlet, checking the meter for indications of downstream leakage (e.g., open fuel line).
- (4) Taking appropriate action when downstream leakage is indicated. This may include actions to prevent unauthorized operation of the meter or service-line valve until downstream leakage is

eliminated.

- (d) Shutting down a pipeline.
See Guide Material Appendix G-192-12.
- (e) Abandoning a pipeline after it is shutdown.
See guide material under §192.727.

2.5 *Maintaining compressor stations.*

During normal maintenance activities, the following should be considered and applied where appropriate.

- (a) Provisions should be made to prevent gas from entering the compressor cylinders of a reciprocating engine or a compressor case of a centrifugal compressor while work is being performed on the units. These provisions should also include the deactivation of the valve operators.
- (b) Provisions should be made to prevent fuel gas from entering the power cylinders of a reciprocating engine or the burner cans of a gas turbine while work is in progress on the unit or equipment driven by the unit.
- (c) Provisions should be made to prevent starting air from entering the power cylinders of a reciprocating engine and to prevent starting air or gas from entering any other starting device on an engine or turbine while work is in progress on the unit or equipment driven by the unit. The flywheel of the reciprocating engine should be locked in a stationary position where possible.
- (d) Recommended methods for isolating the units from sources of gas or starting air include installation of a blind flange, removal of a portion of the supply piping, or locking a stop valve closed and locking a downstream vent valve open. If a common downstream vent is used, provision should be made to prevent backflow to the units.
- (e) Provisions should be made to prevent energizing the electric circuits of a motor driven or motor started compressor unit while work is in progress on the unit or on equipment driven by the unit.
- (f) See 2 and 3 of the guide material under §192.147 for bolting information.
- (g) Provisions should be made to return the equipment to service in an orderly manner to prevent the uncontrolled release of gas to the atmosphere, or overpressuring an isolated or purged piece of equipment or section of pipe.

2.6 *Starting, operating, and shutting down gas compressor units.*

The procedures for the starting, operating, and shutdown of gas compressor units should be in writing and may be developed from operating experience, direct use of manufacturers' instruction manuals, or a combination of both.

2.7 *Periodically reviewing the work done by operator personnel.*

Field oversight including supervisor visits, field inspections, and quality control are some of the methods available to periodically review the work done by operator personnel. The operator should designate a timetable to review personnel performance to determine if the normal operating and maintenance procedures found in the manual are effective and adequate. The operator should determine if deficiencies exist in the procedures. If applicable, modification of procedures should be accomplished as soon as possible. Documentation should be maintained for all procedure modifications and retraining of personnel.

2.8 *Taking precautions in excavated trenches to protect personnel.*

Personnel working in or near a trench should be aware of the potential for an oxygen-deficient environment and of potential dangers from accumulations of gas or vapor, particularly those associated with liquid petroleum gases. When determining the likelihood of gas or vapors presenting such a hazard to personnel, the operator should consider the depth and configuration of the trench, the product transported, and the diameter, pressure, type of piping material, condition, and configuration of the pipeline facilities. Although natural gas is lighter than air and non-toxic, some natural gas pipelines contain constituents such as hydrogen sulfide, heavier-than-air hydrocarbons, and hydrocarbon liquids that may present a hazard to personnel working in or near the trench. The operator should establish criteria for what constitutes a hazardous condition, taking into consideration the LEL of the gas involved. Escaping gas may present an added hazard because of the displacement of oxygen. An

atmosphere containing less than 19.5% oxygen should be considered oxygen-deficient for respiration. When it is necessary for personnel to enter an excavated trench where hazards could reasonably be expected, the operator should consider taking the following actions, as appropriate.

- (a) Confirming that atmospheric monitoring devices, rescue equipment, and breathing apparatus are in working order prior to each use.
- (b) Checking the atmosphere in the excavated trench.
- (c) Establishing a means of exiting the trench.
- (d) Reviewing the rescue plan.
- (e) Placing a safety observer outside the trench to monitor the atmosphere inside the trench and to be available to assist in use of rescue equipment, operation of a fire extinguisher, or otherwise assist in a rescue.
- (f) Minimizing sources of ignition in and around the trench. See guide material under §192.751.
- (g) Taking actions to reduce the accumulation of gas or vapors, such as:
 - (1) Isolating the gas facility by closing valves, squeezing off, bagging off, or using stoppers.
 - (2) Reducing pressure in the facility.
 - (3) Ventilating the work area.
- (h) Requiring the use of flame-retardant clothing, respiratory protection, or a rescue harness and line, as appropriate. The operator's written procedures should describe activities and situations where use of these items is required.

2.9 Responding promptly to a report of a gas odor inside or near a building.

See §192.605(b)(11), which requires procedures in either the procedural manual or its related emergency plan. See 1.1 and 1.3(a) of the guide material under §192.615 for related information.

2.10 Control room management procedures.

See guide material under §192.631.

2.11 Protecting low-pressure distribution systems for overpressurization events.

- (a) Operators should consider developing written procedures for activities involving new construction or pipe replacement projects for low-pressure distribution systems. These procedures should account for the additional precautions needed to protect those systems from an overpressurization event. For more information on the precautions, see the OPS Advisory Bulletin ADB-2020-02 (85 FR 61097, September 29, 2020; reference Guide Material Appendix G-192-1, Section 2).
- (b) Operators should provide step-by-step details that guide the personnel at the job site through a pressure control work task. The sequence of work events is important and adherence to the documented procedure is critical to prevent overpressurization of the system. Personnel should be empowered to stop work if the sequence of work is not followed.
- (c) Procedures should include recognizing abnormal operating conditions. For example, the expected range of pressures during the work task and the MAOP should be communicated to personnel in the field. Actions to take in response to abnormal pressures should be prepared and communicated before starting the construction or pipe replacement project.
- (d) Complex projects with multiple involved work activities could be simplified by breaking into manageable simplified procedures to reduce the risk of unforeseen abnormal operating conditions.

2.12 Management of Change (MOC) practices to minimize the potential for overpressurization.

Operators should consider developing an MOC process for work tasks that have a potential for overpressurization. The MOC is a formal procedure used to identify and consider the impact of changes to pipeline systems and their integrity. Items to address in the MOC include the following.

- (a) The delineation of authority during system work and critical tasks.
- (b) How proposed job changes during the construction phase are approved.
- (c) The level of authority required to make changes to the design and/or project plan.
- (d) That each employee of the operator or the operator's contractor is granted the authority to stop work.
- (e) The collection and sharing of near misses.

See guide material under §§192.631(f) and 192.911(k) for more information on MOC.

3 ABNORMAL OPERATION OF TRANSMISSION LINES

3.1 *General.*

- (a) The abnormal operation requirements in §192.605(c) do not apply to distribution operators that are operating transmission lines in connection with their distribution system (§192.605(c)(5)).
- (b) An abnormal operation is a non-emergency event on a gas transmission facility that occurs when the operating design limits have been exceeded due to a change in pressure, flow rate, or temperature that is outside the normal limits. When an abnormal operation occurs, it does not pose an immediate threat to life or property, but could if not promptly corrected. Where applicable, the actions to be taken by the transmission operator in each situation should incorporate the current procedures. The procedures should be specific enough to ensure uniformity of action relative to the situation, such as those referenced above, while allowing sufficient flexibility to consider the particular details, material, equipment, and configurations involved.

3.2 *Considerations for abnormal operations.*

When developing response procedures for abnormal operations, the transmission operator should consider the following.

- (a) Type of event. See list under §192.605(c)(1).
- (b) Proximity of the event to the public.
- (c) Potential for the event to become an emergency situation if not immediately corrected.
- (d) Effect of the event on the pipeline system.
- (e) Notification of appropriate operator personnel regarding the abnormal operation.
- (f) Documentation of the response actions taken.
- (g) If the event is an increase in pressure outside normal operating limits, the potential for MAOP plus allowable buildup to be exceeded. See 4.4(f) below and (d) of the guide material under §191.23.
- (h) Determine if a failure investigation of equipment is needed in accordance with the requirements of §192.617.

3.3 *Preventing recurrence of abnormal operation.*

Once the event has been investigated, and normal or safe operations have been restored, the operator should determine what measures can be taken to prevent the cause of the event from recurring. The operator should also consider whether these measures should be implemented elsewhere in the transmission system to avoid similar occurrences of abnormal operation.

3.4 *Follow-up monitoring.*

The extent of follow-up monitoring should be based on the nature of the event and the probability that the cause of the event could recur. The abnormal operation is considered corrected when an operator determines, at the end of the monitoring period, that the pipeline facility has maintained operations within its operating design limits and is capable of safely operating up to its MAOP.

3.5 *Follow-up actions to consider.*

- (a) Notify field operations and maintenance personnel to be alert to signs of leakage or damage to pipeline facilities.
- (b) Notify control room personnel, so they can more closely monitor facilities.
- (c) Conduct and document right-of-way patrol of the affected pipeline segment.
- (d) Conduct and document leak survey of the affected pipeline segment.
- (e) Conduct and document inspection of overpressure protection devices for signs of activation. Determine if the devices activated as expected and at the correct pressures.
- (f) Determine probable cause or conduct failure analysis; share results with appropriate personnel. For guidance on performing a failure investigation, see guide material under §192.617.
- (g) Ensure integrity management personnel are informed so this event and associated data can be considered in future risk analyses.
- (h) Review procedural manual, operator qualification program, control room management procedures, and other written procedures for any needed revisions.

3.6 *Review of response activities.*

Response activities should be reviewed based on the extent of the abnormal operation. The review should consider the actions taken and whether the procedures followed were adequate for the given situation or should be revised to provide more specificity or more flexibility.

4 POTENTIAL SAFETY-RELATED CONDITIONS, ANALYSIS, AND ACTIONS

4.1 *Potential safety-related conditions.*

Personnel who perform O&M activities should recognize the following anomalies as potential safety-related conditions that may be subject to the reporting requirements of §191.23.

Note: Reporting requirements for (a), (b), and (d) below apply to a pipeline that operates at 20% or more of SMYS.

- (a) General corrosion that has reduced the pipe wall thickness to less than that required for the MAOP.
- (b) Localized corrosion pitting which has progressed to a degree where leakage might result.
- (c) Unintended movement or abnormal loading by environmental causes (e.g., earthquake, landslide, subsidence, flood) that impairs the serviceability of a pipeline segment.
- (d) Material defects, such as those caused in the manufacturing process, or physical damages that impair the serviceability of a pipeline segment. Sound engineering criteria should be used to determine if an observed condition involving a material defect or physical damage impairs serviceability.
- (e) Malfunctions or operating errors that cause the pressure of a pipeline to rise above its MAOP plus the buildup allowed for the operation of pressure limiting or control devices
- (f) Pipeline leaks that constitute the need for immediate corrective action to protect the public or property. Examples include leaks occurring in residential or commercial areas in conjunction with a natural disaster; leaks where a flammable vapor is detected inside a building; and leaks that involve response by police or fire departments. While venting is done to mitigate an unsafe condition, it does not remove the unsafe condition.
- (g) Other known anomalies or events that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator) for purposes other than abandonment, a 20% or more reduction in operating pressures or shutdown of operation of the affected pipeline segment.

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 with a basic understanding of each element of the procedural manual for operations, maintenance, and emergencies appropriate to the job assignment. A significant change in operating conditions, such as flow reversal or conversion to gas service, might warrant additional training. See 2.7 above regarding periodic reviews, procedure modifications, and retraining of personnel.

6.2 *Operations and maintenance tasks.*
See Subpart N.

6.3 *Emergency response procedures.*
Each operator is required by §192.615(b)(2) to train the appropriate operating personnel to ensure that they are knowledgeable of the emergency procedures. See 2 of the guide material under §192.615.

7 OTHER CONSIDERATIONS

7.1 *"Work authorization" programs.*

Operators should consider including written procedures in their procedural manual for operations, maintenance, and emergencies to protect maintenance workers from the unexpected movement or release of energy when working on electrical, pressurized fluid, or mechanical systems where the inadvertent actuation or release of energy could be dangerous. The procedures commonly used to protect maintenance personnel include "lockout," "tagout," "blocking," and "work authorization" programs. Equipment that should be considered includes compressors, filters, scrubbers, launchers, heat exchangers, and powered valve actuators.

7.2 *Operator's use of powered equipment.*

Before using powered equipment for making an excavation, the operator should consider the following.

- (a) The use of pertinent maps, other records, or other means to locate the operator's facilities.
- (b) Verifying that all other operators of underground facilities in the area have been notified of the pending excavation and have responded by marking their facilities.
- (c) Determining safe distances to be maintained between the digging end of the powered equipment and underground facilities.
- (d) The use of qualified personnel as necessary. See OPS Advisory Bulletin ADB-06-01 (71 FR 2613, Jan. 17, 2006; reference Guide Material Appendix G-192-1, Section 2).

7.3 *Verification of established MAOP*

- (a) Operators should consider including written procedures in their manual for operations, maintenance, and emergencies that address the actions to be taken after records or materials are discovered that may call into question a pipeline's established MAOP. These written procedures should address the following, as applicable.
 - (1) Date the pipeline segment became regulated as outlined in §192.13, and how to address unknown or newly discovered records, or record discrepancies.
 - (2) Review of maintenance and construction activities subsequent to the original pressure test to verify that any repairs, relocations, or replacements meet the MAOP requirements and have the proper test and material documentation.
 - (3) Discovery of a pressure test record used to establish the pipeline's current MAOP that has a lower test value, a shorter test duration, or other test record that does not meet the requirements for a valid pressure test as outlined in Subpart J.
 - (4) Review of §§192.619, 192.621, 192.623 and 192.611 to determine if MAOP calculations are still valid.
 - (5) Options to use field verification for a record indicating an unknown strength or rating, or a pressure rating less than the pipeline's established MAOP.
 - (6) Consideration of an appropriate operating pressure reduction or restriction.

- (7) Coordination with operator's gas control personnel for planning potential operating pressure changes that could affect control room operations.
- (b) If the MAOP verification indicates changes to MAOP are necessary, the operator should consider the following actions.
 - (1) Assessing the impact to the pipeline system.
 - (2) Identifying a remediation strategy for addressing deficiencies.
 - (3) Revising the operator's pipeline records, which may include:
 - (i) manual for operations, maintenance, and emergencies.
 - (ii) gas control records.
 - (iii) gas control alarms.
 - (iv) GIS.
 - (v) electronic databases.
 - (vi) other records and documents where the operator may record pipeline MAOP data.
 - (4) Communicating the change to the appropriate operator personnel.
 - (5) Reviewing and revising overpressure protection requirements.
 - (6) Identifying potential reporting requirements.
- (c) If an operator suspects that liquid hydrocarbons might be present in PE pipe, either from the surrounding soil or from liquid in the gas stream, they should perform a heat fusion melt pattern test on the pipe. If the operator sees bubbles in the PE pipe melt pattern or the fusion bead has a rough, pockmarked surface appearance, this might be an indication that liquid hydrocarbons have permeated the outer pipe wall. The operator should follow their procedures for repair of pipe with an incomplete heat fusion melt pattern. If the operator suspects that liquid hydrocarbons have penetrated the PE pipe wall, see the guide material under §192.121 regarding the effect of liquid hydrocarbons on design pressure. The operator might need to reduce the MAOP established under §192.619 based on the presence of liquid hydrocarbons.
- (d) Operators who have determined that liquid hydrocarbons are present in PE pipes should determine the source of liquid hydrocarbons or gas condensates. If a source can be identified and eliminated, the operator should take appropriate steps to eliminate the liquid hydrocarbons. It is possible for the hydrocarbons to migrate out of the pipe wall over time if the source of contamination is eliminated. If subsequent melt pattern tests no longer have bubbles, the liquid hydrocarbons are no longer present in the PE pipe and the pipe's design pressure no longer requires adjustment due to the liquid hydrocarbons.

§192.607

Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines.

[Effective Date: 07/01/2020]

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

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

(c) **Verification of material properties and attributes.** If an operator does not have traceable,

verifiable, and complete records required by paragraph (b) of this section, the operator must develop and implement procedures for conducting nondestructive or destructive tests, examinations, and assessments in order to verify the material properties of aboveground line pipe and components, and of buried line pipe and components when excavations occur at the following opportunities; Anomaly direct examinations, *in situ* evaluations, repairs, remediations, maintenance, and excavations that are associated with replacements or relocations of pipeline segments that are removed from service. The procedures must also provide for the following:

- (1) For nondestructive tests, at each test location, material properties for minimum yield strength and ultimate tensile strength must be determined in a minimum of 5 places in at least 2 circumferential quadrants of the pipe for a minimum total of 10 test readings at each pipe cylinder location.
- (2) For destructive tests, at each test location, a set of material properties tests for minimum yield strength and ultimate tensile strength must be conducted on each test pipe cylinder removed from each location, in accordance with API Specification 5L.
- (3) Tests, examinations, and assessments must be appropriate for verifying the necessary material properties and attributes.
- (4) If toughness properties are not documented, the procedures must include accepted industry methods for verifying pipe material toughness.
- (5) Verification of material properties and attributes for non-line pipe components must comply with paragraph (f) of this section.

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

- (1) Use methods, tools, procedures, and techniques that have been validated by a subject matter expert based on comparison with destructive test results on material of comparable grade and vintage.
- (2) Conservatively account for measurement inaccuracy and uncertainty using reliable engineering tests and analyses; and
- (3) Use test equipment that has been properly calibrated for comparable test materials prior to usage.

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

- (1) The operator must define separate populations of similar segments of pipe for each combination of the following material properties and attributes: Nominal wall thicknesses, grade, manufacturing process, pipe manufacturing dates, and construction dates. If the dates between the manufacture or construction of the pipeline segments exceeds 2 years, those segments cannot be considered as the same vintage for the purpose of the defining a population under this section. The total population mileage is the cumulative mileage of pipeline segments in the population. The pipeline segments need not be continuous.
- (2) For each population defined according to paragraph (e)(1) of this section, the operator must determine material properties at all excavations that expose the pipe associated with anomaly direct examinations, *in situ* evaluations, repairs, remediations, or maintenance, except for pipeline segments exposed during excavations activities pursuant to § 192.614, until completion of the lesser of the following:
 - (i) One excavation per mile rounded up to the nearest whole number; or
 - (ii) 150 excavations if the population is more 150 miles.
- (3) Prior tests conducted for a single excavation according to the requirements of paragraph (c) of this section may be counted as one sample under the sampling requirements of this paragraph (e).

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

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

- (1) Operators are not required to test for the chemical and mechanical properties of components in compressor stations, meter stations, regulator stations, separators, river crossing headers, mainline valve assemblies, valve operator piping, or cross-connections with isolation valves from the mainline pipeline.
- (2) Verification of material properties is required for non-line pipe components, including valves, flanges, fittings, fabricated assemblies, and other pressure retaining components and appurtenances that are:
 - (i) Larger than 2 inches in nominal outside diameter,
 - (ii) Material grades of 42,000 psi (Grade X-42) or greater, or
 - (iii) Appurtenances of any size that are directly installed on the pipeline and cannot be isolated from mainline pipeline pressures.
- (3) Procedures for establishing material properties of non-line pipe components must be based on the documented manufacturing specification for the components. If specifications are not known, usage of manufacturer's stamped, marked, or tagged material pressure ratings and material type may be used to establish pressure rating. Operators must document the method used to determine the pressure rating and the findings of that determination.

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

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

GUIDE MATERIAL

1 APPLICABILITY

- (a) Section 192.607 only applies to onshore steel transmission pipelines. This section does not apply to offshore transmission, non-steel transmission, gathering, or distribution pipelines.
- (b) Section 192.607 defines a process that an onshore steel gas transmission pipeline operator must follow if there are missing material property or attribute records that are required by other sections of Part 192. Examples include the following.
 - (1) Section 192.624 requires verification of material properties for certain types of pipelines that do not have traceable, verifiable, and complete MAOP records.
 - (2) Section 192.712 requires verification of certain material properties under §192.607 for onshore steel gas transmission pipelines that do not have records necessary to determine the predicted failure pressure (PFP) of a segment for specific anomalies or defects.
 - (3) Even if not explicitly required under Part 192, operators may elect to follow §192.607 to determine material attributes when material records are unknown or unreliable.

2 DOCUMENTATION OF MATERIAL PROPERTIES AND ATTRIBUTES

Records for material properties must be maintained for the life of the pipeline and should be traceable, verifiable, and complete (TVC). Operators should consider digitizing the records to enhance proper organization, security, and controlled access.

3 VERIFICATION OF MATERIAL PROPERTIES AND ATTRIBUTES

- (a) There is no compliance deadline for completing material verification of non-TVC segments or components. The opportunistic gathering of data on unknown material properties does not need to meet the MAOP reconfirmation schedule outlined in §192.624(b), except when the selected MAOP reconfirmation method requires material properties testing to reconfirm the MAOP. The timeframe for opportunistic data collection may vary based on the length of the pipeline, amount of pipe with missing material properties, number of opportunities, and testing results. Section 192.712 requires the operator to know the pipe material properties when conducting the analysis of predicted failure pressure for anomalies or defect evaluations.
- (b) If material properties are unknown and are necessary for an MAOP reconfirmation (per §192.624), an engineering critical assessment (per §192.632), or a failure pressure analysis (per §192.712), then operators should verify the unknown material properties needed on an opportunistic basis.
- (c) Operator procedures should establish specific criteria for identifying when opportunistic sampling is appropriate. Operators should consider when pipeline exposures are safe for material verification and identify criteria that would render an exposure inappropriate for material verification, such as confined space concerns or unstable excavations.
- (d) Section 192.607(c) states that certain types of excavations could require a material verification opportunity for non-TVC segments. Pipeline segment exposures during excavation activities covered under §192.614 are not included in these types of excavations. However, if material verification is performed for non-TVC segments during a one-call excavation, it must be performed per §192.607.
- (e) Depending on the in-line inspection tool capabilities, operators can use pipe grade, wall thickness, and seam type derived from in-line inspection tools for material verification under §192.607(c). Verification of material properties and attributes using nondestructive methods or in-line inspection tools must meet the requirements in §192.607(d).

4 SPECIAL REQUIREMENTS FOR NON-DESTRUCTIVE METHODS

- (a) Operators should consider using in-line inspection tool capabilities that can verify pipe grade, wall thickness, and seam type within the required confidence levels. If using in-line inspection to verify attributes, the operator should ensure its procedures meet the requirements of §192.607(d).
- (b) Depending on the equipment being used for nondestructive testing, operators should consider requiring the equipment used for nondestructive testing to be calibrated on site, in order to prevent the equipment from losing calibration during transit. The documentation associated with the

calibration for nondestructive testing, in accordance with §192.607, should be stored for the life of the pipe with the records used to document the physical pipeline characteristics and attributes.

5 SAMPLING MULTIPLE SEGMENTS OF PIPE

- (a) Operators should only split populations based on known attributes of the pipe and they should have separate populations of pipe segments where material property attributes are unknown. Operators that can document pipe material properties for MAOP (e.g., outside diameter, wall thickness, yield strength, seam type), but are missing the manufacturing or construction date attributes, would not need to conduct an expanded sampling program to determine additional material properties.
- (b) When required material documentation is missing, operators should implement a material sampling program for each unique pipe population group with unknown pipe attributes. Operators can initially group pipe segments with no known material properties information into a single population. When performing material properties testing on pipe from the unknown population group, operators should add newly verified samples into matching pipe populations or create new pipe population groups, as applicable.
- (c) Use of certain in-line inspection tools that can collect material properties would be appropriate to delineate various pipe population groups for subsequent material sampling.
- (d) Operators may take advantage of pipeline excavations and exposures to collect material properties regardless of pipeline location. If operators plan to use material and attribute information collected from pipe segments outside of HCA, MCA, and Class 3 and 4 areas to fulfill the requirements of §§ 192.624 and 192.712, they should adopt and follow procedures for implementing §192.607(e) in those areas as well.

6 COMPONENTS

Some component pressure ratings can be obtained from field inspection if there are visible manufacturing stamps or tags that identify the pressure rating of the fitting. For most flanges, taking measurements of the flange thickness and bolt pattern could help identify the vintage and pressure rating by comparison to early editions of ASME/ANSI B16.1 or ASME/ANSI B16.5.

7 UPRATING

If a segment's MAOP is established using the assumed yield strength of 24,000 psi and material verification of SMYS confirms a higher yield strength or material specification value in accordance with §192.607(d), those verified values may be used to uprate the MAOP of that segment in accordance with Subpart K.

8 ADDITIONAL GUIDANCE

On September 15, 2020, PHMSA issued a final list of Frequently Asked Questions (FAQs) related to the Final Rule titled *"Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments."* This includes FAQs associated with §192.607 *"Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines."* These FAQs can be found within federal docket number PHMSA-2019-0225.

§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.
- (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

This guide material is under review following Amendment 192-132.

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 periodic inspections and reviews as discussed in (a) and (b) below.

- (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, damage, or suspicious activities possibly leading to acts of sabotage. See guide material under §191.5 regarding reporting of such occurrences. *Note:* As appropriate, an operator should report such instances to local law enforcement.
 - (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.
 - (8) Reported vandalism, sabotage, or suspicious activities. Tools and resources to help operators plan, prepare, and protect themselves from suspicious activities or attacks are located online at www.cisa.gov/connect-plan-train-report.
 - (9) As-built and facility location maps.
- (c) 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.
- (d) If a discrepancy is noted between what is observed in the field and the record, the discrepancy should be resolved as soon as practicable. Examples might include:
 - (1) The service line record shows a plastic service line, but in the field it is observed to be a steel line of a different diameter. Ensure records are updated and accurate.

- (2) The service line record for two adjacent homes is shown as a branch service, but when the service tee was retired, one of the homes still remained active with gas pressure. Confirm the source of gas feeding the home and update records to accurately show the facility location.

2 CAST IRON PIPELINES

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

3 PE PIPELINES

3.1 Brittle-like cracking.

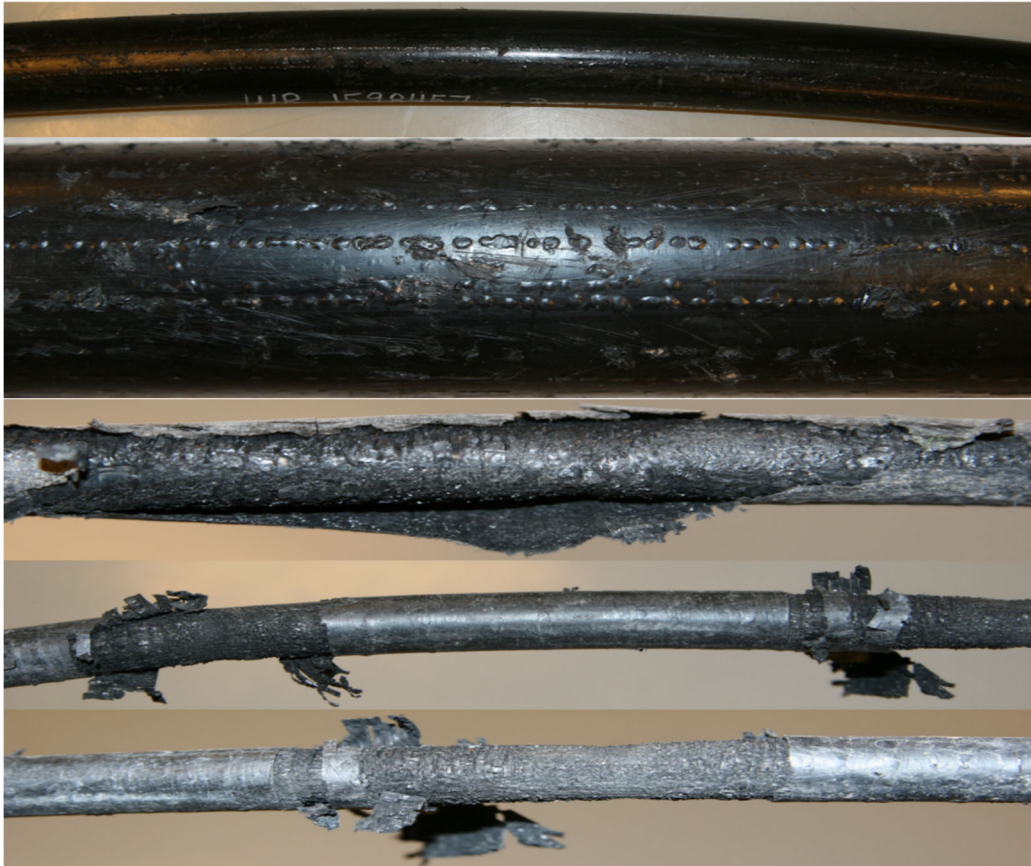
- (a) Some PE materials manufactured before 1982 have a lower resistance to the effects of induced stresses and are subject to brittle-like cracking under certain in-service conditions (e.g., rock impingement, squeeze-offs, severe bending moments). Brittle-like cracking is characterized by a part-through 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.nts.gov/investigations/AccidentReports/Reports/PAB9802.pdf
 - (ii) SIR-98-01 available at www.nts.gov/safety/safety-studies/Documents/SIR9801.pdf
 - (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 <https://www.aga.org/wp-content/uploads/2022/12/gptctechpaper.pdf>.

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 Driscopipe® 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.

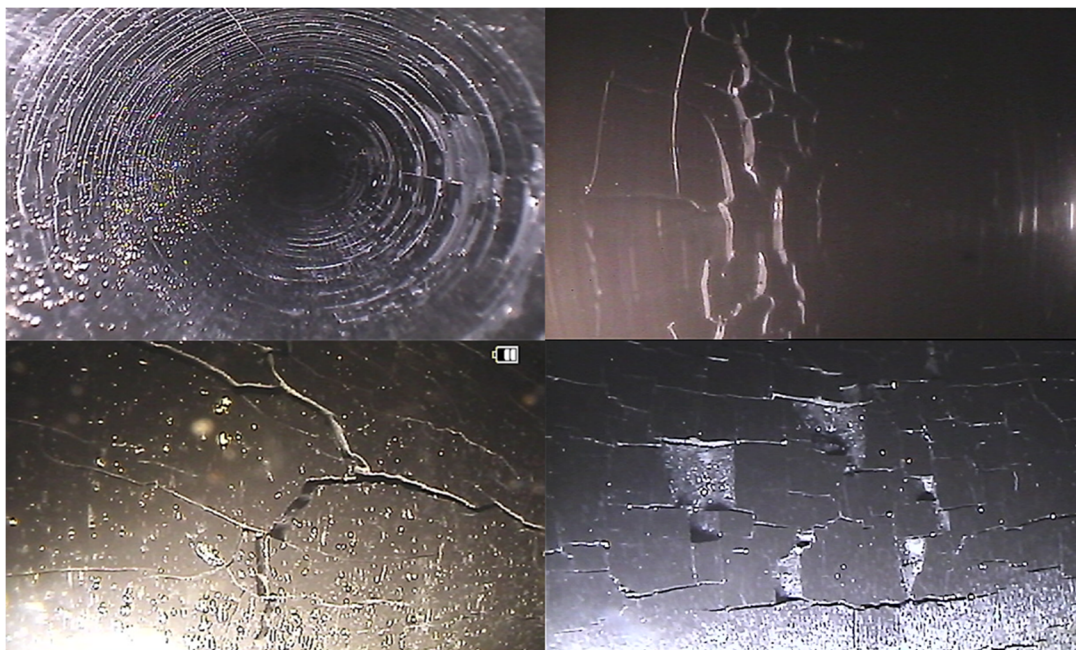


Note: Photographs of pipes provided with permission of the operator.

(d) Internal degradation is not observable unless the pipe is cut apart and the internal surface exposed. Internal degradation might appear as a rough slit crack, spider webbing, or mud cracking on the internal surface of the pipe. Depending on the extent of the degradation, leakage of the pipe might occur. The leak might be visible on the external surface by a slit crack or pinholes bubbling when soap tested. The following factors increase the likelihood of internal degradation for segments of pipe that are not actively flowing gas such as service lines (CTS sizes have experienced more leakage than IPS sizes) that do not supply gas to a customer:

- (1) Increased average and maximum ambient temperatures;
- (2) Increased gas temperature;
- (3) Soil thermal diffusivity;
- (4) Decreased burial depth;
- (5) Ground covers that hold heat, such as concrete and asphalt; and
- (6) Decreased or diminished gas flow (loss of cooling in the pipe).

Internal degradation presents a higher risk of leakage compared to external degradation. Also, CTS sizes have experienced more leakage than IPS sizes. If discovered, additional or accelerated actions for the internal degradation might include accelerated leak survey, replacement, or abandonment of inactive segments of Driscopipe® 7000 and 8000 HDPE pipe.



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

- (e) Each operator that has Driscopipe® 7000 or 8000 HDPE pipe as part of their system should consider implementing the following practices as applicable.
 - (1) Visually inspect Driscopipe® 7000 or 8000 while conducting normal operations and maintenance activities.
 - (2) During squeeze offs, the operator should listen for cracking.
 - (3) Operators in warmer regions of the U.S. should conduct random sampling and testing of pipe in areas at higher risk for thermal degradation considering the factors stated above.
 - (4) Operators in high temperature regions, such as the desert southwest and southern-most regions of the U.S. should sample and test when the opportunity arises and where appropriate, prepare and implement mitigative activities based on their DIMP.
- (f) Methods of evaluating or identifying Driscopipe® 7000 and 8000 HDPE pipe for thermal oxidation include the following.
 - (1) Visual inspection of affected pipe for blistering, delamination, or peeling of the external or internal surfaces.
 - (2) Listening for popping or crunching sounds during the squeezing of the pipe.
 - (3) Bend-back testing per ASTM D2513 (Section 5.12); affected pipe is likely to show signs of cracking or crazing.
 - (4) Oxidative induction time (OIT) testing per ASTM D3895 conducted on the external and internal surfaces. An OIT value of five minutes or less is indicative of significant stabilizer depletion in the pipe and such values warrant other mitigation measures.
 - (5) Fourier transform infrared (FTIR) spectroscopy testing might show possible carbonyl peaks at $1711\text{-}1715\text{cm}^{-1}$. As peaks due to the additives of the compound might also show up in this range, further evaluation is required to confirm the presence of degradation.
- (g) For additional information, see OPS Advisory Bulletin ADB-2012-03 (77 FR, 13387, Mar. 6, 2012; for reference Guide Material Appendix G-192-1, Section 2).

4 STEEL TRANSMISSION LINES - STRESS CORROSION CRACKING (SCC)

4.1 SCC.

SCC is a form of environmentally assisted cracking (EAC), a generic term to describe all types of cracking in pipelines where the surrounding environment, pipe material, and stress act together to reduce the pipe strength or load-carrying capacity. Stress corrosion cracks typically occur in a colony or cluster, and stress and corrosion work together to weaken the pipe. The tensile stresses required to initiate SCC may result from directly applied stresses (pressure and overburden) or residual stresses (fabrication and construction). If not mitigated, cracks may grow to sizes that threaten the integrity of a pipeline.

(a) Types of SCC.

Two types of SCC may be found on underground steel pipe.

- (1) "Near-neutral pH SCC," also known as low-pH or non-classical SCC, with the following basic characteristics.
 - (i) Transgranular.
 - (ii) Limited branching.
 - (iii) Associated with some corrosion of the crack walls and pipe surface.
 - (iv) Associated with a near-neutral electrolyte (pH 6.0 to 8.0).
- (2) "High pH SCC," also known as classical SCC, with the following basic characteristics.
 - (i) Intergranular.
 - (ii) Typically branched.
 - (iii) Associated with an alkaline electrolyte (pH 9.0 to 11.0).

Table 192.613i below summarizes the characteristics of near-neutral pH SCC and high pH SCC.

TYPICAL CHARACTERISTICS OF SCC IN PIPELINES		
Factor	Near-neutral pH SCC	High pH SCC
Location	<ul style="list-style-type: none"> ○ Associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings. 	<ul style="list-style-type: none"> ○ Typically within 20 miles downstream of a compressor station. ○ Number of failures reduces markedly with increased distance from compressors and lower pipe temperature. ○ Associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings.
Temperature	<ul style="list-style-type: none"> ○ No apparent correlation with temperature of pipe. ○ Appears to occur more frequently in the colder climates where CO₂ concentration in groundwater is higher. 	<ul style="list-style-type: none"> ○ Growth rate increases exponentially with temperature increase.
Operating Pressure	<ul style="list-style-type: none"> ○ In excess of 60% SMYS. 	<ul style="list-style-type: none"> ○ In excess of 60% SMYS.
Associated Electrolyte	<ul style="list-style-type: none"> ○ Dilute bicarbonate solution with a neutral pH in the range of 6.0 to 8.0. 	<ul style="list-style-type: none"> ○ Concentrated carbonate-bicarbonate solution with an alkaline pH greater than 9.3.
Electrochemical Potential	<ul style="list-style-type: none"> ○ Free corrosion potential: –760 to –790 mV (Cu/CuSO₄). ○ Cathodic protection does not reach pipe surface at SCC sites. 	<ul style="list-style-type: none"> ○ Free corrosion potential: –600 to –750 mV (Cu/CuSO₄). • Cathodic protection is effective to achieve these potentials.
Morphology	<ul style="list-style-type: none"> ○ Primarily transgranular (across the steel grains). ○ Wide cracks with evidence of substantial corrosion within crack side wall. 	<ul style="list-style-type: none"> ○ Primarily intergranular (between the steel grains). ○ Narrow, tight cracks with almost no evidence of secondary corrosion within crack side wall.

TABLE 192.613i

(b) New pipelines.

The most effective method of preventing SCC on new pipelines is to apply a high-performance coating system (e.g., fusion bonded epoxy, urethane, liquid epoxy, extruded polyethylene, multi-layer coating) to a properly prepared surface and then to apply cathodic protection.

(c) SCC susceptibility.

There are a number of approaches for assessing and prioritizing pipeline susceptibility to SCC, and no single method is recommended over another. What is important is that a consistent approach be used that includes both technical and environmental factors that contribute to reducing the overall risk of a potential SCC occurrence. The following characterizations should be used to evaluate SCC susceptibility.

- (1) Failure history - Identify past SCC failures.
- (2) Coating type (e.g., coal-tar, tape) — Address condition and type of coating, including the type of surface preparation on the pipe prior to coating application.
- (3) Pipe material (e.g., API grades, pipe mill).
- (4) Operations (e.g., pressure, temperature).
- (5) Location - Correlate the environmental conditions near the pipeline with the occurrence of SCC.
 - (i) Use of soil models to correlate with potential coating disbondment segments.

- (ii) Drainage, local topography, soil disposition, and similar aspects of soil models, tied with time in service, are seen as predictors of potential coating failures.
- (6) Age.
- (7) Bellhole - Trending analysis of buried pipe inspection reports to identify common characteristics in pipe with SCC compared with pipe having no SCC.
- (8) Magnetic flux leakage in-line inspection (ILI) results.
- (9) Other ILI results.
- (10) Cathodic protection level — Monitor CP voltage levels at locations with and without active SCC.
- (11) Hydrostatic retest program – Testing pipe to determine presence of SCC.
Note: If critical size cracks are present, a rupture of the line will likely occur.
- (d) Follow-up actions for positive indications of SCC susceptibility.
A written inspection, examination, and evaluation plan should be prepared when pipelines are determined to be susceptible to SCC.
 - (1) *Inspection.*
The inspection objectives are to conduct aboveground or other types of measurements to supplement, if needed, the data collected and analyzed to determine SCC susceptibility. This data should then be used to prioritize susceptible segments and to select the specific sites for direct examination. Inspection examples include the following.
 - (i) Close-interval survey.
 - (ii) Coating-fault survey.
 - (iii) ILI geometry tool.
 - (iv) ILI electromagnetic acoustical transducer (EMAT) tool.
 - (v) Hydrostatic test.
 - (2) *Examination.*
Examination should include procedures to field-verify sites selected for direct examination. Any SCC detected should be followed by an assessment of its severity, extent, and type at the individual dig-site.
 - (3) *Evaluation.*
An operator's evaluation plan should address the following.
 - (i) Method used to determine whether general SCC mitigation is required.
 - (ii) Prioritize remedial action for defects that are not removed immediately.
 - (iii) Evaluate the effectiveness of the SCC approach.
- (e) Mitigation.
 - (1) The necessity for and type of mitigation activity are typically dependent on the type of cracking present. Primary guidance for SCC mitigation is provided in ASME B31.8S, Appendix A3 and NACE SP0204, Section 6, "Post Assessment." In addition, ASME B31.8S, Table 4 and PRCI L52047, "Pipeline Repair Manual," list industry- recognized mitigation methods for SCC. These methods are included in Table 192.613ii, below and more than one may be applied.
 - (2) Other mitigation methods for SCC that are not shown in the table should be performed with materials and processes suitable for the pipeline's operating conditions and meeting applicable codes and standards.
 - (3) Additional guidance on mitigation methods may be found in ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas," which documents a joint industry project.

4.2 References.

- (a) ASME B31.8S, Appendix A3 and Table 4 (see listing in §192.7, not IBR for §192.613).
- (b) ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas."
- (c) NACE Publication 35103, "External Stress Corrosion Cracking of Underground Pipelines."
- (d) NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."
- (e) National Energy Board (Canada), Report of the Inquiry MH-2-95, "Stress Corrosion Cracking on Canadian Oil and Gas Pipelines," December 1996.

- (f) OPS Advisory Bulletin ADB-03-05 (68 FR 58166, Oct. 8, 2003; see Guide Material Appendix G-192-1, Section 2).
- (g) OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study," Michael Baker, Jr., Inc., January 2005.
- (h) PRCI L52047, "Pipeline Repair Manual."
- (i) "SCC Detection and Mitigation Based on In-Line Inspection Tools," W. Kresic and S. Ironside, Paper # IPC2004-0375 presented at ASME International Pipeline Conference, Calgary, October 2004.

INDUSTRY-RECOGNIZED MITIGATION METHODS	
Mitigation Method	Description
Pressure Reduction	Used to decrease the likelihood of an immediate or near-term SCC failure. The pressure reduction provides time for the operator to assess the pipeline integrity and determine a long-term mitigation and management strategy.
Replacement	Replacement of selected pipe segments can be used to eliminate stress corrosion colonies.
Grinding	Removal of cracks by grinding to sound metal. Assess remaining strength, using a method such as RSTRENG, and then recoat.
Repair Sleeves, Bolt-on Clamps, or Composite Reinforcement	In conjunction with grinding, repair sleeves, bolt-on clamps, or composite reinforcements are able to permanently restore the serviceability of the pipe. These repair items may be installed if grinding of an excavated section of pipeline results in a wall thickness less than the minimum required for the MAOP. To mitigate SCC, the ground-out area should be filled with incompressible filler when a repair sleeve is used. The operator should follow the manufacturer's instructions and the operator's repair procedures.
Recoating	Recoating a pipeline can improve the resistance of the pipe to SCC. If disbonded, dielectric coatings (e.g., tapes, shrink sleeves) are frequent contributors to SCC. In addition, mill scale remaining on the pipe surface after preparation for coating has also been linked to SCC. Any remaining mill scale can be removed during surface preparation prior to recoating. Grit blasting conducted during the surface preparation process increases resistance to SCC by imparting a compressive residual stress on the pipe surface.
Hydrostatic Testing	<ul style="list-style-type: none"> • Hydrostatic testing and repair can be used to reduce the likelihood of a stress corrosion failure. Hydrostatic testing will cause critical cracks (at the test pressure) to fail. By repairing these failures, critical cracks are eliminated, although near-critical cracks at the test pressure could remain undetected. • Using hydrostatic testing alone requires retest on a regular basis to find stress corrosion cracks that may have become critical since the previous test. • Recommended hydrostatic test criteria are found in ASME B31.8S, Appendix A3.4.2.
In-Line Inspection	In-line inspection suitable for crack detection, and subsequent

INDUSTRY-RECOGNIZED MITIGATION METHODS	
Mitigation Method	Description
	repairs, can be used to reduce the likelihood of a stress 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) Cathodic protection current shielding.
- (4) Failed insulators.
- (b) Corrosion discovered through an ILI run or other integrity assessment that requires remedial action in accordance with §§192.485 or 192.933.
- (c) Evidence of internal corrosion or conditions conducive to internal corrosion including observed liquids or significant changes in gas quality.
- (d) Excavation damage or conditions conducive to excavation damage to the pipeline.
- (e) Damage or conditions conducive to damage to the pipeline by natural or other force.
- (f) Evidence of potential material failure of pipe or weld.
- (g) A leak.
- (h) Any abnormal operation (e.g., loss of communications, overpressure or pressure fluctuations, pipeline security concerns). See §192.605(c)
- (i) Recent construction or demolition activity of nearby structures.
- (j) Change in number of structures intended for human occupancy that could affect class location or HCA determination.

§192.614

Damage prevention program.

[Effective Date: 07/20/98]

(a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline shall carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations.

(b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.

(1) The state has adopted a one-call damage prevention program under §198.37 of this chapter; or

(2) The one-call system:

(i) Is operated in accordance with §198.39 of this chapter;

(ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and

(iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:

(i) The program's existence and purpose; and

(ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:

(i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and

(ii) In the case of blasting, any inspection must include leakage surveys.

(d) A damage prevention program under this section is not required for the following pipelines:

(1) Pipelines located offshore.

(2) Pipelines, other than those located offshore, in Class 1 or 2 locations until

September 20, 1995.

(3) Pipelines to which access is physically controlled by the operator.

(e) Pipelines operated by persons other than municipalities (including operators of master meters) whose primary activity does not include the transportation of gas need not comply with the following:

(1) The requirement of paragraph (a) of this section that the damage prevention program be written; and

(2) The requirements of paragraphs (c)(1) and (c)(2) of this section.

[Issued by Amdt. 192-40, 47 FR 13818, Apr. 1, 1982; Amdt. 192-57, 52 FR 32798, Aug. 31, 1987; Amdt. 192-73, 60 FR 14646, Mar. 20, 1995; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-82, 62 FR 61695, Nov. 19, 1997; Amdt. 192-84, 63 FR 7721, Feb. 17, 1998 with Amdt. 192-84 Removal, 63 FR 38757, July 20, 1998 and Amdt. 192-84 Correction, 63 FR 38758, July 20, 1998]

GUIDE MATERIAL

Note: Section 192.616 requires most operators, including Type A and Type B gathering line operators, to develop and implement a written continuing public education program that follows the guidance provided in API RP 1162 for identifying and notifying excavators and the affected public about damage prevention. These identification and notification activities are required by §192.614. Guide material for these program activities is provided in 2.3, 2.4, and 2.5 below.

1 SCOPE

This guide material covers damage prevention programs for buried pipelines, including Type A and Type B gathering lines. The guide material excludes pipelines specified under §192.614(d) and (e) that are exempt from the requirement for a written damage prevention program. For considerations to minimize damage by outside forces, see Guide Material Appendix G-192-13.

Some activities performed as requirements for damage prevention may also be used to satisfy similar program requirements under §§192.615, 192.616, 192.620(d)(2), and 192.935.

2 WRITTEN PROGRAM

Written procedures, when required, should state the purpose and objectives of the damage prevention program and provide methods to achieve them. For program content, operators should review applicable state and local one-call requirements. A reference for state requirements is the One Call Systems International (OCSI) Resource Guide, which provides a summary of the damage prevention laws in each state, found at <https://commongroundalliance.com/map>. In addition, operators should review the Common Ground Alliance's "Best Practices" Guide, found at <https://commongroundalliance.com/best-practices-guide>. The procedures should include the following.

2.1 *Definition of excavation activities.*

In defining excavation activities to be covered by the damage prevention program, the operator should review the definition in §192.614(a) and applicable state and local requirements. Additional definitions for “excavation” and “excavator” can be found in 49 CFR §196.3.

2.2 *One-call systems.*

- (a) A one-call system may exist that does not meet the qualification requirements of §192.614(b)(1) or (b)(2). If the operator participates in a non-qualified one-call system, either because a qualified one-call system does not cover the area or for any other reason, the operator should consider working with that one-call system to make it qualified.
- (b) If a one-call system covering the operator’s facilities does not exist, the operator should consider establishing a qualified one-call system with other underground facility operators.
- (c) The operator is cautioned that satisfying the requirements of §192.614 may require more than participation in a one-call system. The operator should evaluate the services being provided by the one-call system to determine what additional measures may need to be taken to satisfy the requirements of §192.614.

2.3 *Identifying entities to be informed of the program.*

- (a) Excavators. The sources listed below may be helpful when preparing the list of entities engaged in excavation activities. The procedure should provide for a periodic review of the list to ensure that it is current.
 - (1) One-call center.
 - (2) Contractor licensing agencies.
 - (3) Contractor associations.
 - (4) Local utilities.
 - (5) Pipeline companies.
 - (6) Insurance carriers.
 - (7) State, county, and local road maintenance offices.
 - (8) Operator records that could provide information on excavation activities, such as pipeline patrols.
 - (9) Farmers, adjacent landowners, and industrial complex operators (e.g., asphalt plants, cement plants, mines, and quarries).
 - (10) State, county, and local permitting agencies.
 - (11) Outside consultants, such as direct mail contractors or public relations firms.
 - (12) Telephone yellow page directory and electronic database listings, such as the following.
 - (i) Excavating and earth moving contractors.
 - (ii) Construction contractors.
 - (iii) Blasting contractors.
 - (iv) Well drilling and boring contractors.
 - (v) Landscaping contractors.
 - (vi) Land leveling and subsoiling contractors.
 - (vii) Dredging companies.
 - (viii) Plumbers.
 - (ix) Fence erectors.
 - (x) Power line contractors.
- (b) The public. The public in the vicinity of the pipeline can be identified by land and tax records, census (Tiger) files, operator and pipeline rights-of-way data, or field survey. The general public should be informed for distribution systems. For transmission systems, the public may include the following.
 - (1) Residents living on, or adjacent to, the pipeline rights-of-way.
 - (2) Businesses adjacent to the pipeline rights-of-way.
 - (3) Easement holders.
 - (4) Utility companies.
 - (5) Homeowner organizations.
 - (6) Other pipeline companies within the area.

- (7) Church groups.
- (8) Schools.
- (9) One-call centers.
- (c) Government organizations. The following government organizations should be considered for receiving program information.
 - (1) Federal, state, county, and municipal governments.
 - (2) Local fire, police, and sheriff departments.
 - (3) Emergency management agencies.
 - (4) Building departments.
 - (5) Highway departments.
 - (6) State land departments.
- (d) Railroads. Railroad operators whose rights-of-way contain pipeline should be identified. Railroads operating within the area of the pipeline operator may be identified through the Federal Railroad Administration.

2.4 *Methods of informing entities of the program.*

One-call centers and outside consultants, such as direct mail contractors or public relation firms, may be considered to assist the operator with distribution of program materials and information.

- (a) Excavators. Actual notification is required to persons who normally engage in excavation activities in the area in which the pipeline is located. Actual notification means providing information directly to the excavator. Methods of providing actual notification should include one or more of the following to target the excavators identified under 2.3 of this section.
 - (1) Mail addressed to the excavator.
 - (2) Telephone.
 - (3) Electronic notification, such as email.
 - (4) Personal visit.
 - (5) Excavator awareness seminars conducted by the operator acting alone, with other underground facility operators, or through one-call notification system(s) in which the operator participates may supplement actual notification activities.

The operator should consider documenting these actions. Procedures for periodic renotification of excavators should be established based upon use of the program.

- (b) The public. Operators should consider the following methods for notification of the public about the operators' damage prevention programs. These methods may also be used to complement and reinforce the message excavators receive from the actual notification methods listed under 2.4(a) above.
 - (1) Mailings.
 - (2) Bill stuffers.
 - (3) Handouts.
 - (4) Newspaper, magazine, television, or radio advertisements.
 - (5) Speakers supplied to local groups.
 - (6) Using permitting authorities and public officials to disseminate information.
 - (7) Joint mailings with other utilities.
 - (8) Vehicle advertising signboards.
 - (9) Decals for construction equipment and the pipeline operator's vehicles.
 - (10) Specialty advertising, such as bumper stickers or imprinted mementos.
 - (11) Notices in telephone directories.
 - (12) Public education programs related to §192.616.
 - (13) School programs.
 - (14) Personal visits.
 - (15) Maps.
 - (16) Exhibits or displays at appropriate public gatherings.
 - (17) News releases or interviews.
 - (18) Specific information packets designed for distribution to individual dwelling units at apartments

and condominiums.

- (19) Specific information packets designed for distribution to businesses for employee education.
- (20) Electronic communications, such as web pages, email, or social media.
- (21) Billboards or signs.
- (22) News articles (as opposed to advertising) covering safety functions, programs, messages or available information.

2.5 *Information to be communicated.*

Entities that may engage in excavation activities should be informed of the purpose of the program, how they can learn the location of underground pipelines before commencing excavation activities, and actions to be taken if the pipeline or its related components, such as tracer wire, warning tape, and passive locating devices, are hit or damaged. Illustrations or pictures of the various types of pipeline locations should be included. Program information should also advise that even minor residential activities, such as installing fences or performing landscaping, could cause pipeline damage.

- (a) The programs and methods of informing entities that may perform excavation activity as described in 2.4 above should be designed to educate excavators about their obligations under applicable state laws and regulations, including the following.
 - (1) How to provide notice of intent to dig, emphasizing the importance of using a one-call notification system (e.g., 811), where applicable.
 - (2) How far in advance of excavation activity must the notice of intent to dig be provided.
 - (3) Waiting the required time to allow operators to mark their facilities.
 - (4) Verifying the location of facilities by hand digging test holes.
 - (5) Support and protection of exposed facilities.
 - (6) Minimum clearances of powered equipment from facilities.
 - (7) Preservation of markings.
 - (8) Pipe support, backfill, and compaction requirements.
 - (9) Reporting discovery of unknown or unmarked underground facilities.
 - (10) Reporting damages or emergencies. See §192.616.
 - (11) Pre-marking the excavation area with white paint.
 - (12) Avoidance of disturbing cast iron facilities.
 - (13) Safe excavation, support, and backfilling requirements unique to cast iron facilities.
- (b) In addition, the following should be addressed in communications with excavators.
 - (1) The importance of promptly reporting damage of the facilities to the pipeline operator, securing the area, and standing by at a safe distance.
 - (2) Avoiding any attempt to repair the damage or restrict the flow of gas and leaving necessary repairs to be made by the pipeline operator. This includes the following considerations.
 - (i) Allow the gas to vent to atmosphere.
 - (ii) Do not put out the flame if gas ignites, but let it burn. Burning gas will not explode.
 - (iii) Do not cover the damaged pipe with dirt as a means of stopping the leak.
 - (iv) Do not kink or crimp gas pipe.
 - (v) Do not attempt to plug damaged pipe.
 - (3) Denting, gouging, and surface damage that appears minor can lead to future failure.
 - (4) The serious consequences that can result from coating damage.
 - (5) See guide material under §192.616 for information to be communicated regarding gas pipeline emergencies.
 - (6) The importance of properly communicating information regarding GPS readings, when they are used.
 - (i) This includes use of GPS devices that are WAAS-enabled (Wide Area Augmentation System), which is intended to increase the accuracy of GPS readings.
 - (ii) Verify that the reference datum selected for the GPS coordinates is the same reference datum used by the one-call center (typically NAD 83).
 - (iii) GPS coordinate nomenclature should be the same as that used by the one-call center. Typically "Decimal Degrees" format (e.g., -30.8910972) is used instead of the other two common GPS formats known as "Degrees, Minutes, and Seconds" (e.g., -30° 53' 27.95")

and "Degrees and Decimal Minutes" (e.g., -30° 53.4658').

- (c) Railroad operators should be made aware of concerns specific to pipeline operators, including how train derailments and response activities related to these accidents could affect the pipeline.
- (d) Operators of cast iron systems should instruct builders, designers, and excavators regarding areas in their territory where cast iron facilities exist.
- (e) Operators of cast iron systems may plan and design cast iron main replacements in conjunction with, or in advance of, local infrastructure replacement projects, such as paving projects and replacement of water or sewer facilities. This practice not only becomes economical because of the restoration savings, it also reduces risk of cast iron failure before, during, or after construction.
- (f) Where past or present trenchless technology practices exist, operators should communicate the possibility of cross bores affecting the sewer mains and laterals. Audience should include water and sewer utilities, residents, plumbing contractors, and rental equipment stores. See OTD-12/0003, "Cross Bore Best Practices – Best Practices Guide."

2.6 *Receiving excavation notification.*

The operator should establish a telephone number and mailing address for receiving notifications of planned excavation activities in areas where its underground facilities are not covered by a one-call system. Provisions should be made for recording all notifications (e.g., using a log, form, or memo), and for the retention of such records, whether the notifications are received through a one-call system or directly from the excavator. The record should include the following.

- (a) Name of person giving notification.
- (b) Name of entity which will be conducting excavation activities.
- (c) Telephone number for contacting the entity.
- (d) Location of the planned excavation activities.
- (e) Date and time of commencement of excavation activities.
- (f) Type and scope of excavation activities.

Participation in a one-call system does not preclude the operator from receiving such notification directly from individuals, such as may result from observation of a pipeline marker. Operators should inform callers to make notifications directly to the one-call system.

2.7 *Responding to excavation notification.*

- (a) Preparation. The operator should develop procedures for responding to notifications of intent to excavate. Consideration should be given to the following.
 - (1) How information about the location of existing and newly installed facilities may be obtained from maps, records, digital or aerial imagery, or field investigation. If the operator's records include GPS coordinates, the reference datum and nomenclature to be used should be clearly documented.
 - (2) How individuals responding to excavation notifications can have access to up-to-date pipeline alignment and as-built drawings.
 - (3) Standards for marking facilities consistent with the field conditions, including items such as the use of paint on paved areas and stakes, and signs or flags in unpaved areas. A reference for marking facilities is the Common Ground Alliance's "Best Practices" Guide, available at <https://commongroundalliance.com/best-practices-guide>.
 - (4) Availability of personnel who are qualified (see Subpart N) to mark facilities as necessary.
 - (5) The potential for facility markings to become obscured prior to, or during, excavation activity and appropriate action to be taken.
 - (6) Whether a response to the excavator should be made when the operator has no facilities or knowledge of abandoned facilities located in the area of excavation activity. The operator should also review state and local regulations to determine if other response requirements apply.
- (b) Response. Where facilities exist in the area of excavation activity, the operator should respond to the notification prior to the planned start of the excavation activity. The operator should consider documenting the response. The response should include the following.
 - (1) Marking the operator's pipeline facilities, including laterals, in the area of the proposed

excavation activity. In areas where the pipeline facilities are curved or make sharp bends, consider the visibility and frequency of markings. Individually mark pipeline facilities located in the same trench or right-of-way. If metallic facilities are exposed during locating activities, see guide material under §192.459.

- (2) Conducting an onsite meeting if there is potential for misunderstanding concerning the location of facilities or the procedure for marking.
- (3) Reviewing for accuracy any maps, drawings, or records supplied to an excavator to assist in locating underground facilities or abandoned facilities when known. Unless field checked, it is suggested that they be marked with a note such as "Not responsible for accuracy, verify by hand digging."
- (4) Participating in, coordinating, or conducting pre-excavation meetings, when appropriate, with other facility owners and excavators. Special attention should be given to large or complex projects. Discuss aspects of the planned excavation activities, marking schedules, and lines of communication. Provide the excavators with information about the underground pipeline facilities in order to avoid damage. The operator should discuss the potential for facility markings becoming obscured and corrective measures.
- (5) Ensuring adequate separation between a buried foreign structure to be installed and the adjacent pipeline by coordination with the owner or operator of the foreign structure. See guide material under §192.325.
- (6) Advising excavators who plan to use trenchless methods (e.g., boring) of potential damage to gas pipeline facilities. See Guide Material Appendix G-192-6 for protecting existing gas facilities.
- (7) For operators of cast iron facilities, advising excavators at the job site of the following.
 - (i) Cast iron may fail when subjected to undermining and disturbance.
 - (ii) How to avoid undermining or disturbing the cast iron facilities.
 - (iii) Notify the operator immediately if the main is either undermined or disturbed.
- (8) For operators of cast iron facilities, documenting known conditions where facilities have been undermined or disturbed to aid in the study for determining future replacement needs as required under §192.755. Also, see Guide Material Appendix G-192-18, Section 4.
- (9) If dredging operations are involved, consider an enhanced tolerance zone and other precautions listed in the following resources.
 - (i) Recommended Best Practice Guide for Safe Dredging near Underwater Gas and Liquid Pipelines, Council for Dredging and Marine Construction Safety (<https://cdmcs.org>)
 - (ii) Coastal and Marine Operators' Pipeline Industry Initiative (www.camogroup.org)

(c) Records. Operators should document their responses to excavation notifications.

2.8 Inspecting pipelines.

- (a) Need and schedule. Each notification should be evaluated to determine the need for, and the extent of, the inspection. Where required, the inspection may include periodic or full-time surveillance and may include leak surveys during and after construction. The operator should consider maintaining field contact with the excavator during the excavation activities to avoid potential problems and to promptly resolve any problems that may arise. The following factors should be considered in determining the need for, and extent of, inspections.
 - (1) Type and duration of the excavation activity involved.
 - (2) Proximity to the operator's facilities.
 - (3) Located within a High Consequence Area (HCA). If the inspection work is on a covered segment of transmission line, the operator is required to follow the additional items described in §192.935. For threat of third-party damage, see 2 of the guide material under §192.935.
 - (4) Type of excavating equipment involved.
 - (5) Importance of the operator's facilities.
 - (6) Type of area in which the excavation activity is being performed.
 - (7) Potential for a serious incident should damage occur.
 - (8) Past experience of the excavator.
 - (9) Potential for damage occurring which may not be easily recognized by the excavator, such as

- improper support during excavation and backfill or trenchless installations (e.g., boring).
- (10) Potential for facility markings to become obscured.
- (b) Onsite inspection. When onsite inspection is performed, the operator should use qualified personnel as necessary to ensure that the excavator is doing the following (see OPS Advisory Bulletin ADB-06-01; 71 FR 2613, Jan. 17, 2006; reference Guide Material Appendix G-192-1, Section 2).
- (1) Verifying the location of the facilities by hand digging test holes.
 - (2) Supporting and protecting exposed facilities.
 - (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

Notes:

- (1) Although not required, operators should consider developing an emergency plan for Type B gathering lines.
- (2) To differentiate between operators' emergency response personnel and processes and those of public agencies and administrations, the term *operator* (or a variant) is used to denote pipeline operators' personnel and processes. Similarly, the term *local* is used for public agencies, such as fire, police, and other public officials.
- (3) Some activities performed as requirements for emergency plans may also be used to satisfy similar program requirements under §§192.614, 192.616, 192.620(d)(2), and 192.935.

1 WRITTEN EMERGENCY PROCEDURES (§192.615(a))

- (a) Written procedures should state the purpose and objectives of the operator's emergency plan and provide the basis for instructions to their appropriate personnel. The objective of the plan should be to ensure that operator personnel who could be involved in an emergency are prepared to recognize and deal with the situation in an expeditious and safe manner.
- (b) Establishing written procedures may require that parts of the plan be developed and maintained in coordination with local emergency response personnel and with other entities in or near the pipeline rights-of-way (e.g., other utilities, highway authorities, and railroads) that may need to respond to a pipeline emergency.
- (c) Written procedures should also include instructions on interfacing with the Incident Command System (ICS) typically used by local emergency responders. See 1.2 below for interfacing with an ICS and 1.10 below for general information about the ICS.
- (d) If applicable, written procedures should include a reference to Control Room Management procedures associated with a controller's roles and responsibilities during emergency conditions. See 3.2(c) of the guide material under §192.631
- (e) To ensure the safety of the general public, an operator's written procedures should provide for the following as applicable.

1.1 *Receiving, identifying, and classifying emergencies.*

- (a) Provisions should be made to ensure prompt and adequate handling of all calls, reports, or indications concerning emergencies (see §192.615(a)(3)), whether they are from customers, the public, operator employees, SCADA systems, or other sources. The following should be included.
 - (1) Arrangements for receiving notification of an emergency at any hour of the day. When an answering service is used, answering service personnel should be trained and have updated emergency call-out lists of operator personnel for emergency response.
 - (2) Directions to operator employees who receive calls considering the following.
 - (i) The information received should be assessed in order for the operator to react properly to the call and to inform the caller of precautionary actions to be taken prior to the arrival of operator personnel. Personnel receiving notices of gas leaks or odors should obtain the following basic information from the caller and inform the caller that access will be required.
 - (A) Name.
 - (B) Address of leak or odor.
 - (C) Telephone number.
 - (D) Reason for call.
 - (E) Location of the odor (inside or outside).

- (ii) Additional questions that could be asked to assist in determining the priority for action, and if additional instructions should be provided to the caller, include the following.
 - (A) Strength of odor?
 - (B) Length of time odor has been present?
 - (C) Was anyone working on indoor gas piping or appliances?
 - (D) Is there any construction in the area?
 - (E) Can you hear evidence of escaping gas?
 - (F) What type of building or facility is involved?
 - (iii) If the answers to these or other questions indicate a potentially hazardous situation, consideration should be given to providing additional instructions to the caller, such as the following.
 - (A) Do not create a source of ignition by operating switches, electrical appliances, or portable telephones.
 - (B) Evacuate the area and wait for operator personnel to arrive.
 - (C) Call back from a safe location to provide additional information for response personnel.

Note: The operator should confirm that the caller understands the instructions and repeat instructions as necessary.
 - (iv) If gas leakage or other hazard is determined to be significant, the operator should consider contacting the local emergency response agency. The operator should call 911 where appropriate, informing them of the emergency situation and providing pertinent information.
- (3) Operator personnel receiving emergency calls should receive periodic refresher training on leak call procedures, communication skills, and reporting procedures. Periodic performance reviews should be conducted during actual leak calls.
- (b) Instructions to operator personnel should ensure that the information received is evaluated to determine the priority for action. Some situations call for operator personnel to be dispatched promptly for an on-the-scene investigation. Those personnel should respond in an urgent manner giving a potential emergency top priority until the severity of the situation has been determined. Some situations require that priority be given to other actions, such as notification to gas control, other operator or local emergency response personnel. See 3.3 below.
- Examples of emergency situations that require immediate response include the following.
- (1) Gas ignition or explosion.
 - (2) A hissing noise is present or there is any indication of a broken or open-ended pipe.
 - (3) Report of a pulled service or damaged facility.
 - (4) Report of a release that may be representative of an unintentional and uncontrolled release, requiring evaluation to confirm if a rupture has occurred.
 - (5) Observation by operator of an unanticipated or unplanned pressure loss outside normal operating parameters as defined in operating procedures.
 - (6) Observation by operator of an unexplained flow rate or pressure change, or instrumentation indication that may be representative of a rupture.
 - (7) Gas odor throughout the premise or building.
 - (8) Other identified (i.e., operator designated) emergencies.
- (c) In a combination utility (e.g., gas with electric, water or other utilities), training should be provided to personnel of other utilities or divisions to inform the gas operator and other applicable entities of gas leak, gas odor, or other pertinent information provided by customers or the general public.

1.2 *Establishing and maintaining adequate means of communication.*

- (a) Arrangements made for establishing and maintaining adequate public and operator communications should be described. These arrangements should include means of communication with appropriate fire, police, and other public officials. Operators may opt to establish liaison with local emergency coordinating agencies such as 911 call centers or emergency managers in lieu of fire, police, and other public officials individually, and should consider the need for the following.

- (1) Continuously updated operator and public emergency call lists that will show how to contact personnel that may be required to respond to an emergency at any hour.
 - (2) Resources and responsibilities must be determined for jurisdictional areas and emergency contacts for local and out-of-area calls (§192.615(a)(2)).
 - (3) Multiple telephone trunk lines to the emergency operations center.
 - (4) Additional switchboard facilities and personnel.
 - (5) "Unlisted" telephone service to ensure accessibility to operator-only calls.
 - (6) Additional fixed and mobile radio equipment.
 - (7) Standby electrical generating equipment for communications power supply.
 - (8) Dissemination of accurate information to the news media and cooperation with the news media on the scene.
 - (9) A social media program to gather and disseminate information.
- (b) Instructions for working effectively with the local ICS should be described as follows.
- (1) When local emergency responders have set up an Incident Command prior to the arrival of operator personnel:
 - (i) The first operator person to arrive should introduce himself to the Incident Commander as the representative from the gas pipeline operator, and
 - (ii) That person remains the point of contact until the incident has been made safe or until relieved of that duty by another operator representative.
 - (2) When local emergency responders are not yet on the scene:
 - (i) The first person representing the operator to arrive will serve as Command, and
 - (ii) That person should assess the situation and take, or direct, all necessary actions to protect people, protect property, and secure the flow of gas.
 - (3) If local emergency responders arrive later and set up an ICS:
 - (i) The Command for the gas pipeline operator should introduce himself as the point of contact for the operator, brief the local Incident Commander, and
 - (ii) That person should remain the point of contact until the incident has been made safe or until relieved of that duty by another operator representative.
- (c) Instructions to operator personnel should ensure that the information received is evaluated to determine the priority for action. Some situations call for operator personnel to be dispatched promptly for an on-the-scene investigation. Those personnel should respond in an urgent manner giving a potential emergency top priority until the severity of the situation has been determined. Some situations require that priority be given to other actions, such as notification to gas control, other operator personnel, or local emergency response. See 3.3 below. Examples of emergency situations that require immediate response include the following.
- (1) Gas ignition or explosion.
 - (2) A hissing noise is present or there is any indication of a broken or open-ended pipe.
 - (3) Report of a pulled service or damaged facility.
 - (4) Gas odor throughout the premise or building.
 - (5) Other identified (i.e., operator designated) emergency.
 - (6) Report of tampering, vandalism, suspicious activity, or unauthorized access. See guide material (j) and (k) under §191.5.
- (d) Consider providing operator's first-responder personnel with intrinsically safe communication devices to carry with them while on duty. Be aware of communication blind spots.

1.3 *Prompt and effective response to each type of emergency.*

Various types of emergencies will require different responses in order to evaluate and mitigate the hazard. Consideration should be given to the following.

- (a) Emergencies involving gas detected in or near buildings should be prioritized in order to have sufficient operator personnel for response. For leak classification and action criteria, refer to Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems. See §192.605(b)(11), which requires procedures for prompt response to reports of a gas odor in or near buildings.

- (b) Emergencies involving damage to buried facilities during excavation activities should be assessed for potential hidden and multiple leak locations.
- (c) Emergencies involving fire located on or near pipeline facilities may require those facilities to be isolated. If a major delivery point is involved, an alternative gas supply may be needed.
- (d) Emergencies involving an explosion on or near pipeline facilities may result in damage from fire and shock waves.
- (e) Emergencies involving an explosion or fire where non-typical soil conditions exist (e.g., water-saturated ground, frozen ground) that might affect gas migration and the ability of an operator to quickly find the source of the suspected leak. See Guide Material Appendices G-192-11, Section 5.5 and G-192-11A, Section 5.5.
- (f) Emergencies involving blowing or ignited gas may hinder local emergency responders' search and rescue efforts.
- (g) Emergencies involving a potential or confirmed rupture must be immediately and directly communicated to the an appropriate public safety answering point (e.g., 911 call centers) or an emergency coordinating agency to determine the location of any release, regardless of whether the segment is subject to requirements for transmission line valves. (§192.615(a)(8))
- (h) Natural disasters, such as earthquakes and other significant earth movement (e.g., landslides, mudslides, sinkholes), floods, hurricanes, tidal waves, tornadoes, or wildfires, might affect the safe operation of pipeline facilities in many different ways. Manmade disasters, such as mine subsidence, sabotage, infrastructure collapse, or corrosive chemical discharge, might also affect safe operations. Operators affected by these disasters should dispatch personnel to the areas as soon as practicable to evaluate the situation and proceed with emergency response related to their gas facilities, as necessary, to keep or make conditions safe. Operators of pipeline facilities affected by natural disasters should address these situations in the emergency procedures and consider preparing a disaster plan including site-specific procedures, if appropriate. The procedures and plan may include the items listed below.

Note: Multiple advisory bulletins have been issued regarding the potential for damage to pipeline facilities caused by the passage of hurricanes and flooding. For examples, see OPS Advisory Bulletin ADB-2015-02 (80 FR 36042, June 23, 2015; see Guide Material Appendix G-192-1, Section 2) and the advisory bulletin referenced in 6 of the guide material under §192.613.

- (1) Information on responsibilities for operator personnel communication and work assignments.
- (2) Information on alternative reporting locations for operator personnel in case the primary location is damaged or inaccessible.
- (3) Procedures to assess damage, mitigate hazardous conditions, and minimize hazards of released gas to life, property, or the environment, which may include the following.
 - (i) Establishing an operations and communications command center.
 - (ii) Establishing a field command post.
 - (iii) Determining personnel, material, and equipment requirements.
 - (iv) Deploying personnel to sites and locations where they can take appropriate actions, such as shutdown, pressure reduction, isolation, or containment.
 - (v) Evaluating the accessibility of pipeline facilities that may be in jeopardy such as valves and regulator stations needed to isolate the system.
 - (vi) Performing frequent patrols to evaluate the effects on pipeline facilities.
 - (vii) Determining the extent of damage to pipeline facilities.
 - (viii) Ensuring line markers are still in place or replaced in a timely manner for operator-defined critical locations or facilities.
 - (ix) Determining if facilities that are normally above ground (e.g., valves, regulators, relief devices) have become submerged and are in danger of being struck by vessels or debris. Facilities in danger of being struck by vessels should be marked with an appropriate buoy if the locations can be reached safely.
 - (x) Performing surveys to determine the depth of cover over pipelines and the condition of any exposed pipelines, such as those crossing scour holes or where water channels have changed. For pipelines in the Gulf of Mexico and its inlets with waters less than 15 feet deep, see §192.612.
 - (xi) Evaluating right-of-way conditions at water crossings during the flooding and after waters

subside by performing patrols, including appropriate overflights. Notify appropriate staff of any localized or systemic flooding to determine whether pipeline crossings may have been damaged or would be in imminent jeopardy from future flooding.

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

- (4) Procedures to re-establish normal operations including service restoration and progress tracking and reporting. For large-scale outages of distribution systems, see Guide Material Appendix G-192-7.
- (5) Other considerations.
 - (i) Maintaining mutual assistance agreements with other pipeline operators.
 - (ii) Providing accommodations for operator personnel and other assisting personnel.
 - (iii) Shutting off gas service to an affected area if evacuations of that area are being made by police or fire departments.

1.4 *Assuring the availability of personnel, equipment, tools, and materials.*

Arrangements made to assure the availability of personnel, equipment, tools, and materials that may be needed should be described in accordance with the type of emergency. These arrangements should include the assignment of responsibilities for coordinating, directing and performing emergency functions, including the following.

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

1.5 *Controlling emergency situations.*

Actions that may be initiated by the first employee arriving at the scene in order to protect people and property should be described. These actions may include the following.

- (a) Determining the scope of the emergency.
- (b) Evacuating and preventing access to premises that are or may be affected.
- (c) Preventing accidental ignition.
- (d) Reporting to the appropriate supervisor on the situation and requesting further instructions or assistance, if needed.

1.6 *Emergency shutdown and pressure reduction.*

(a) Provisions for shutdown or pressure reduction in the pipeline system as may be necessary to minimize hazards should be described. The plans should include the following.

- (1) Circumstances under which available shutdown, pressure reduction, or system isolation methods are applicable. Considerations should include the following.
 - (i) Access to, and operability of, valves located in areas prone to high water or flooding conditions.
 - (ii) Proximity to buildings and other structures.
 - (iii) Proximity to local emergency responders' search and rescue area.

- (2) Circumstances under which natural gas might be allowed to safely escape to the atmosphere (i.e., vent) until shutdown or repair.
 - (i) Some possible reasons for using this alternative are as follows.
 - (A) Curtailment will affect critical customers (e.g., hospitals).
 - (B) Curtailment will affect large numbers of customers during adverse weather conditions.
 - (C) Line break or leak is remotely located and does not cause a hazard to the public or property.
 - (ii) Some factors to consider are as follows.
 - (A) Sources of ignition.
 - (B) Leak or damage location (rural vs. urban).
 - (C) Proximity to buildings and other structures.
 - (D) Local emergency responders' ability to access the search and rescue area.
 - (E) Ability to make and keep the area safe while gas vents.
 - (F) Ability to coordinate with operator and local emergency responders and public officials.
- (3) Lists or maps of valve locations, regulator locations, compressor schematics, and blowdown locations.
- (4) Maps or other records to identify sections of the system that will be affected by the operation of each valve or other permanent shutdown device.
- (5) Provision for positive identification of critical valves and other permanent facilities required for shutdown. See 2.2 of the guide material under §192.605.
- (6) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
- (7) Provisions for notifying affected customers.
- (8) Provisions for confirming that the shutdown or pressure reduction was effective.
- (b) Distribution system plans should include consideration of the potential hazards associated with an outage and the need to minimize the extent of an outage, and to expedite service restoration. In addition to the use of any existing emergency valves within a distribution system, consideration should also be given to other methods of stopping gas flow, such as:
 - (1) Injecting viscous materials or polyurethane foam through drip risers or any other available connections to the main.
 - (2) Use of squeeze-off or bagging-off techniques.

1.7 *Making safe any actual or potential hazard.*

Provisions should be described for identifying, locating, and making safe any actual or potential hazard. These may include the following.

- (a) Controlling pedestrian and vehicular traffic in the area.
- (b) Eliminating potential sources of ignition.
- (c) Controlling the flow of leaking gas and its migration. See Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.
- (d) Ventilating affected premises.
- (e) Venting the area of the leak by removing manhole covers, barholing, installing vent holes, or other means.
- (f) Determining the full extent of the hazardous area, including the discovery of gas migration and secondary damage such as the following.
 - (1) Deformation of a gas service line indicating that the service line might be separated underground near a foundation wall or at an inside meter set assembly.
 - (2) Multiple underground leaks that may have occurred, allowing gas to migrate into adjacent buildings.
 - (3) Potential pipe separation and gas release at unseen underground locations that may result in gas entering adjacent buildings, or following or entering other underground structures connected to buildings.
- (g) Monitoring for a change in the extent of the hazardous area.
- (h) Determining whether there are utilities whose proximity to the pipeline may affect the response.

- (1) Visually identify the presence of electric and other utilities surrounding the pipeline facility.
 - (2) Evaluate the potential risk associated with the continued operation of the surrounding utilities.
 - (3) Use the local ICS to contact the owner of the surrounding utilities, as necessary, to implement a more effective and coordinated emergency response.
- (i) Coordinating the actions to be taken with fire, police, and other public officials, including the following.
- (1) Search and rescue efforts.
 - (2) Ensuring information pertinent to emergency response is shared in a timely manner.

1.8 *Restoration of service.*

Planning for the safe restoration of service to all facilities affected by the emergency, after proper corrective measures have been taken, should include consideration of the following.

- (a) Provisions for safe restoration of service should include the following.
- (1) Turn-off and turn-on of service to customers, including strict control of turn-off and turn-on orders to assure safety in operation.
 - (2) Purging and repressurizing of pipeline facilities. For service lines containing an EFV, see guide material under §192.381 for purging considerations.
 - (3) Resurvey of the area involved in a leak incident to locate any additional leaks.
- (b) Execution of the repair and restoration of service functions will necessitate prior planning, such as the following.
- (1) Sectionalizing to reduce extent of outages and to expedite turn-on following a major outage.
 - (2) Lists and maps for valve locations, regulator locations, and blowoff or purge locations.
 - (3) Provisions for positive identification of valves and regulator facilities. See 2.2 of the guide material under §192.605.
 - (4) Equipment checklist for repair crews.
 - (5) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
 - (6) Emergency supply connections with other gas companies and procedures for making use of such connections.
 - (7) List of contractors, utilities, and municipalities that have agreed to provide equipment and workers to assist with repair and service restoration. Procedures for securing and utilizing this equipment and workforce should be described.
 - (8) Prearranged use of facilities, owned by others, for temporary operating headquarters for repair and restoration activities. Arrangements should also be made for all necessary support functions for such temporary operating headquarters.
 - (9) Cooperation with appropriate civil organizations in providing housing and feeding facilities for persons requiring shelter during an outage in severe weather.
 - (10) Arrangements to maintain service to critical customers, such as hospitals, to the degree possible during a general service curtailment or outage. In addition, a similar priority should be assigned for turn-off activities.
- (c) For large-scale outages, also see Guide Material Appendix G-192-7.

1.9 *Providing for investigation of failures.*

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

- (a) Keeping a log of significant events and of actions taken.
- (b) Preserving failed facilities or equipment for analysis, as may be appropriate.
- (c) Obtaining and submitting information required by jurisdictional regulatory agencies.
- (d) Including the requirement for post-accident / incident drug and alcohol testing. See Part 199 – Drug and Alcohol Testing and OPS Advisory Bulletin ADB-2012-02 (77 FR 10666, Feb. 23, 2012; see Guide Material Appendix G-192-1, Section 2).

1.10 *Incident Command System (ICS).*

- (a) In the context of applying the ICS, the Federal Emergency Management Agency (FEMA) has defined the term incident as "an occurrence, either caused by humans or natural phenomena, that requires

response actions to prevent or minimize loss of life or damage to property and/or the environment." Certain gas emergencies could fall within the FEMA definition of an incident. Examples of FEMA incidents include the following.

- (1) Fire, both structural and wildland.
 - (2) Natural disasters, such as tornadoes, floods, ice storms, or earthquakes.
 - (3) Human and animal disease outbreaks.
 - (4) Search and rescue missions.
 - (5) Hazardous materials incidents.
 - (6) Criminal acts and crime scene investigations.
 - (7) Terrorist incidents, including the use of weapons of mass destruction.
 - (8) National Special Security Events, which are designated by the U.S. Department of Homeland Security (e.g., Presidential inaugurations, national political conventions, major sporting events).
 - (9) Other planned events, such as parades or demonstrations.
- (b) The ICS is a management system for dealing with emergencies. It has been developed from reviewing past emergencies and formalized into a structured system by FEMA and other emergency response agencies. It is a consistently applied system for controlling on-site personnel, facilities, equipment, and communications in an emergency. It is a designated system used from the time a FEMA incident occurs until the requirements for implementing the ICS no longer exist.
- (c) When an operator and local emergency responders implement an ICS, respective plans may differ but should be based on similar principles so the plans are compatible. The ICS may be used for small or large incidents, remaining adequately flexible to adjust to the changing needs of an incident.
- (d) The ICS functions typically include the following.
- (1) Safety – public and employees.
 - (2) Security – utilize operator or local public safety personnel.
 - (3) Commander responsibilities – establish command center, transfer of command.
 - (4) Operational – incident stabilization plan, repair plan.
 - (5) Logistics – material, equipment, other resources.
 - (6) Public relations – communications, notifications, information liaison.
 - (7) Personnel management.
- (e) The ICS supports responders and decision makers by providing the data they need through effective information and intelligence management. The data provided may include information on the following.
- (1) Maps and records for critical infrastructure and other facilities.
 - (2) Load studies.
 - (3) Affected customers, including residential, commercial, and industrial customers.
- (f) Additional information on the ICS can be found at: training.fema.gov/emiweb/is/icsresource/

1.11 *Role of control room during an emergency.*

If applicable, an operator should provide controllers with procedures and tools when controllers are required to respond to an emergency in accordance with §192.631.

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

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

2.1 *Provide employees access to emergency procedures manual.*

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

2.2 *Training of employees.*

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

Those responsible for instruction of operator employees should place special emphasis on the following.

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

2.3 *Review of employee activities.*

Following each emergency, employee activities should be reviewed, by examining the log of events and actions taken, to determine whether the procedures were effectively followed. Consideration should be given especially to whether responses to the emergency were timely. In addition, consideration should be given to the need for changes in the written procedures as may be indicated by the experience gained during the emergency.

3 **LIAISON WITH PUBLIC OFFICIALS (§192.615(c)) AND OPERATORS OF FACILITIES IN THE VICINITY OF THE PIPELINE**

Note: Section 192.616 requires most operators to develop and implement a written continuing public education program that follows the guidance provided in API RP 1162 for stakeholder audiences that include emergency officials and public officials. Information provided to emergency and public officials under a public awareness program may address some of the requirements of §192.615(c), but may not adequately address all the "liaison" requirements. The liaison requirement of §192.615(c) is expected to bring an operator and respective emergency responders and public officials together to exchange information regarding emergency response that is specific to the operator's systems and facilities. Added guidance for liaison with emergency officials is provided below.

Those responsible for establishing liaison with appropriate public officials and operators of facilities in the vicinity of the pipeline (e.g., telephone, electric, gas, cable, water, sewer, and railroads), with respect to emergency procedures, should consider the following.

3.1 *Compiling current information on the resources of government organizations.*

- (a) Organization's name.
- (b) Type of responsibility.
- (c) Geographic area covered.
- (d) Availability to assist in case of a pipeline emergency.
- (e) Responsibility and resources for fire, bodily injury, control, and area evacuation problems in connection with a gas pipeline emergency.
- (f) Type, size, and capacity of equipment and vehicles.
- (g) Procedures to facilitate prompt communications in emergencies.
- (h) Level of training of responders.

3.2 *Acquainting public officials with emergency procedures.*

- (a) Appropriate fire, police, and other public officials should be informed of the availability, capability, and location of the operator's personnel, equipment, and materials for response to gas pipeline emergencies. They should be provided with a list of the appropriate employees who can be contacted at any hour. The importance of immediate contact should be stressed.
- (b) Consideration should be given to involving local public emergency response personnel in operator-simulated emergency exercises and post-exercise critiques. In areas where multiple pipeline operators have facilities, consideration should be given to joint emergency training and liaison activities with the local emergency response officials.
- (c) For additional information on this subject, see OPS Advisory Bulletin ADB-10-08 (75 FR 67807, Nov. 3, 2010; see Guide Material Appendix G-192-1, Section 2).

3.3 *Identifying emergencies that require notification to and from public officials.*

- (a) The types of emergencies that might require notification of public officials by gas system operators include the following.
 - (1) A serious fire or a fire on adjacent property.
 - (2) Serious bodily injury.
 - (3) Where the number of people involved or the spectators are too numerous for the operator to handle.
 - (4) Adjacent to public rights-of-way where the public could be endangered.
 - (5) Where an area patrol or area evacuation is needed.
 - (6) An incident in a highly populated area.
- (b) The types of emergencies that might require notification to operators by public officials include the following.
 - (1) Report of gas odor.
 - (2) Damage to gas facilities.
 - (3) Operation of a gas system valve by non-operator personnel.
 - (4) Report of a gas outage.

3.4 *Plan with public officials and operators of facilities in the vicinity of the pipeline for mutual assistance.*

- (a) Operator personnel should establish and maintain liaison with appropriate fire, police, and other public officials and operators of facilities in the vicinity of the pipeline to plan how to engage in mutual assistance to minimize hazards to life and property. This planning should include how to work together effectively in an Incident Command System and the means to ensure communication of pertinent information is ongoing and timely during an emergency response. Consideration should be given to various situations including the following.
 - (1) Operator has reason to believe a hazard may exist and where local emergency personnel may be able to respond more quickly than operator personnel. Fire and police department personnel should take action toward protecting the public by means of evacuation and building ventilation, where needed, pending the arrival of operator personnel.
 - (2) Evacuation of buildings and properties.
 - (i) Advise police and fire departments that operator personnel may need to conduct leak

- investigations inside buildings and on properties within the area of the emergency.
- (ii) The operator, police department, and fire department should plan for access to evacuated buildings and properties. The plan should include provisions to instruct personnel in charge of evacuated buildings and properties to provide a means of access, when required.
 - (3) Operation of electric, other utilities, or mechanical equipment located in the vicinity of the pipeline may provide sources of ignition for the gas released, may increase burning time or intensity of fires that have already started, or may delay responders who are attempting to make the situation safe.
 - (4) Pipeline is located in proximity to a derailed train, near or within a railroad right-of-way, where pipeline damage may not be apparent or suspected. Pipeline operators should inform railroad operators and local emergency response officials of the presence, location, and depth (if known) of their pipeline. Knowledge of pipeline existence could reduce hazards to people working at and around the accident location, and could prevent damage or rupture of the pipeline due to the movement of heavy equipment within or near the railroad right-of-way. For additional information, see OPS Advisory Bulletin ADB-2012-08 (77 FR 45417, July 31, 2012; reference Guide Material Appendix G-192-1, Section 2).
 - (5) Flooding has occurred or the threat of flooding might have jeopardized pipeline crossings. The following actions should be considered:
 - (i) Provide relevant information, such as maps, to emergency responders so appropriate response strategies can be developed.
 - (ii) Communicate with local and state officials to address potential concerns related to the flooding (e.g., pipeline exposures, localized flooding, ice dams, debris dams, bank erosion) that might affect pipeline integrity.
 - (iii) Coordinate with other pipeline operators in flood areas and establish or work with emergency response centers to act as a liaison for pipeline problems and solutions.
 - (6) Gas migration to other areas via underground paths (e.g., sewers or other conduits).
- (b) The gas characteristics and properties, such as pressure, specific gravity, gas odor, and flammability limits, should be provided to local emergency response officials. The implications of these characteristics and properties on emergency response decisions should be thoroughly discussed. In discussions with local emergency response officials, the operator should emphasize the following.
- (1) The importance of this information to local emergency response personnel arriving before operator personnel.
 - (2) The use of this information in making decisions, such as areas to be evacuated, traffic rerouting, and control of ignition sources.
 - (3) The importance of gas detectors in properly responding to an incident.

§192.616

Public awareness.

[Effective Date: 01/14/08]

(a) Except for an operator of a master meter or petroleum gas system covered under paragraph (j) of this section, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice (RP) 1162 (incorporated by reference, see §192.7).

(b) The operator's program must follow the general program recommendations of API RP 1162 and assess the unique attributes and characteristics of the operator's pipeline and facilities.

(c) The operator must follow the general program recommendations, including baseline and supplemental requirements of API RP 1162, unless the operator provides justification in its program or procedural manual as to why compliance with all or certain provisions of the recommended practice is not practicable and not necessary for safety.

(d) The operator's program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a gas pipeline facility;

(3) Physical indications that such a release may have occurred;

(4) Steps that should be taken for public safety in the event of a gas pipeline release; and

(5) Procedures for reporting such an event.

(e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations.

(f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas.

(g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.

(h) Operators in existence on June 20, 2005, must have completed their written programs no later than June 20, 2006. The operator of a master meter or petroleum gas system covered under paragraph (j) of this section must complete development of its written procedure by June 13, 2008. Upon request, operators must submit their completed programs to PHMSA or, in the case of an intrastate pipeline facility operator, the appropriate State agency.

(i) The operator's program documentation and evaluation results must be available for periodic review by appropriate regulatory agencies.

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

(1) A description of the purpose and reliability of the pipeline;

(2) An overview of the hazards of the pipeline and prevention measures used;

(3) Information about damage prevention;

(4) How to recognize and respond to a leak; and

(5) How to get additional information.

[Issued by Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-99, 70 FR 28833, May 19, 2005 with Amdt. 192-99 Correction, 70 FR 35041, June 16, 2005; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE17, 72 FR 70808, Dec. 13, 2007]

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) Tenants that are not direct gas customers occupying multi-family residential building/units or multi-commercial units. Operators should also consider notifying those residents and business owners who may be renters or leaseholders along its pipelines that might not be direct customers of a gas distribution operator. This group might include the following.

(1) Working in subdivided buildings or office campuses or complexes.

(2) Residing in apartments, student housing, transitional housing, rental units, or other types of residential units.

(c) Emergency officials and local public officials with land use authority.

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

(d) Excavators.

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

(e) 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 and Appendix D 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

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

Addendum 1, June 2022

Addendum 4, May 2024

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 Appendix G-192-8, Section 10.

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, consider following the evaluation steps in 9 below.

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.

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(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

above.

- (b) For a failure that does not elevate to the level of an incident, an operator may follow the data collection steps. See 5.1 above.

6 INVESTIGATION

A subject matter expert (SME) individual or team can perform an extensive evaluation or a more simplified evaluation based on the nature of a system and its operation. The SME should be knowledgeable by training or experience in the procedures for the investigation of an incident or other failure.

6.1 *Incident.*

When a detailed analysis is to be made, an SME investigation team should be designated. The investigation should include the following.

- (a) Determination of the probable cause.
- (b) Evaluation of the initial response.
- (c) The need for system improvements, if necessary.
- (d) The need for improvements in response, management, and investigation.

6.2 *Other failures.*

Assign an internal SME individual or team.

6.3 *Evaluation*

Consider testing the involved facilities, performing a leak or other survey of the involved area, or inspecting for signs of recent excavation activity.

7 SPECIMENS

As used in this section, a *specimen* is any physical evidence such as a pipe, joint, fitting, meter, other material, soil, or other sample that may be collected as part of a failure investigation.

- (a) Procedures for excavating the area over and around the specimen at the failure location should include precautions such as hand digging, vacuum excavation, or other appropriate methods to avoid causing damage to any potential specimen, pipelines in the vicinity of the excavation near the specimen, or the surrounding environment.
- (b) Procedures should be prepared for selecting, collecting, preserving, labeling, and handling of specimens.
- (c) Procedures for collecting plastic or metallurgical specimens should include precautions against changing the granular structure in the areas of investigatory interest (e.g., avoid heat effects from cutting and outside forces due to tools and equipment).
- (d) Procedures may be necessary for proper sampling and handling of soil and groundwater specimens where corrosion may be involved.
- (e) Procedures controlling the cutting, cleaning, lifting, identifying, and shipping of pipe specimens should be considered for preservation of valuable evidence on the pipe surface, and on any tear surface or fracture face, including making cuts far enough from the failure to avoid damaging critical areas of the specimen.
- (f) The number of specimens needed to be collected at the failure site may vary depending on the type and number of tests anticipated. A series of independent or destructive tests may require multiple specimens. If there is a need to confirm the pipe material specifications, then additional pipe specimens should be obtained near the failure, but in an area of the piping where the physical properties and characteristics are unaffected by the failure itself. Other investigatory procedures may be utilized to confirm pipe material specifications.

8 TESTING AND ANALYSIS

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

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

9 CONSIDERATIONS FOR MECHANICAL FITTINGS

If the cause of a mechanical fitting failure is not readily apparent in the field and the operator chooses to conduct further evaluation off-site, the following is provided for evaluating either a nut-follower or a stab-type fitting. Other compression fittings, if investigated for failure, can follow the same basic principles as covered below. Participation by the manufacturer or referencing the manufacturer's literature (if available) early in the investigation can provide more accurate information.

9.1 *Mechanical fitting failure evaluation for nut-follower fittings.*

- (a) Before disassembly, the operator should:
- (1) Use a checklist to capture as much information as practicable.
 - (2) Mark the 12 o'clock position of fitting with the pipe component while the unit is still in place.
 - (3) Photograph and document external observations, both at the failure site before cutting out and then at the evaluation facility.
 - (4) After proper shutdown and purge of gas, cut out the fitting without disturbing the pipe connection and transport the unit to the evaluation location. Do not attempt to disassemble in the field.
 - (5) Document whether any external blocking or restraint devices were found in the field.
 - (6) Classify and document the surrounding soil.
 - (7) Contact the manufacturer if the problem appears to be with the integrity of the fitting.
 - (8) Document whether any wrench marks or other surface damages are on the fitting body.
 - (9) Document whether nuts on bolted-type fittings appear to be evenly tightened.
 - (10) Document pipe and fitting characteristics, such as nominal size, SDR, schedule, and wall thickness.
 - (11) Document the "printline" marking on pipe and fitting.
 - (12) Document observations, such as cracking, delamination, and sand holes.
 - (13) Document leak path location.
 - (i) Leak through fitting body – Fitting failure.
 - (ii) Leak through sealing area – Joint Failure.
 - (14) Determine an unknown leak path with a method such as the following.
 - (i) Cap the unit using test fittings.
 - (ii) Inject a fluorescein solution into the assembly and gradually pressurize.
 - (iii) Illuminate with UV light and identify specific leak path.
 - (iv) Drain fluorescein and allow time to dry before disassembling. Dry fluorescein in the leak path may be visible after disassembly. This is particularly important in cases where scratches on pipe create a leak path.
 - (15) Mark pipe and fitting for stab depth and apparent leak location.
 - (16) Mark the position of nuts or followers.
 - (17) Photograph again.
 - (18) Test the torque on nuts or followers, if appropriate.
 - (19) For a pullout failure:
 - (i) Examine pipe surface for marks or indentations indicating excavation damage.
 - (ii) Record position of stiffener relative to pipe end.
- (b) During assembly, the operator should:
- (1) Maintain relative position of pipe, fitting, and components as practicable.
 - (2) Not saw or cut into fitting or pipe unless necessary. If necessary, do so in a manner that allows position of components to be accurately determined after disassembly.
 - (3) Count turns required to remove nuts or bolts. Precision down to 1/16th turn or better is helpful.
 - (4) Compare the actual turns found to those recommended by manufacturer. If uncertain, contact the manufacturer.

- (c) After assembly, the operator should:
- (1) As soon as practicable, take high-resolution, close-up photographs of external and internal surfaces of pipe and components to record indentations and other evidence.
 - (2) Document any damaged, cut, or distorted components.
 - (3) Verify the leak path, such as looking for fluorescein traces on pipe and sealing member under UV light.
 - (4) Record the condition of the internal retainer ring since, in some metal mechanical fitting designs, deformation of the internal retainer ring is evidence that the fitting was improperly torqued at installation. In many cases, the retainer ring might be difficult to remove from the nut if improper torque was applied.
 - (5) Document whether the gasket or O-ring appears to be distorted and photograph the condition.
 - (6) Document and photograph any scratches on the pipe under the gasket.
 - (7) Document whether there is dirt or other debris between the gasket and pipe.
 - (8) Document whether scratches, dirt, or debris line up with the fluorescein traces.
 - (9) For a pullout failure:
 - (i) Take note of any indicators on pipe surface of gradual or sudden movement of pipe relative to fitting.
 - (ii) Determine whether the joining procedure used was qualified in accordance with §192.283(b).
 - (10) Document whether all components are present and in correct orientation.
 - (11) Document whether the correctly sized stiffener was used for the plastic piping being connected.
 - (12) Document whether the joining procedure was qualified per §192.283(b).
 - (13) Use the documented findings to help identify the apparent cause of mechanical joint failure.

9.2 *Mechanical fitting failure evaluation for boltless stab fittings (2-inch and smaller).*

The operator should:

- (a) Use a checklist to capture as much information as practicable.
- (b) Mark the 12 o'clock position of fitting with the pipe component while the unit is still in place.
- (c) Photograph and document external observations, both at the failure site before cutting out and then at the evaluation facility.
- (d) After proper shutdown and purge of gas, cut out the fitting without disturbing the pipe connection and transport the unit to the evaluation location. The operator should not attempt to disassemble in the field.
- (e) Document whether any external blocking or restraint devices were found in the field.
- (f) Classify and document the surrounding soil.
- (g) Contact the manufacturer if the problem appears to be with the integrity of the fitting.
- (h) Document whether any wrench marks are on the fitting body.
- (i) Cut fitting in half.
- (j) Determine whether the chamfer was proper for the installed fitting: internal for internal O-ring seal and external for external seal.
- (k) Document whether the pipe was cut square.
- (l) Document the condition of O-rings (e.g., torn, pinched).
- (m) Document the condition of pipe external wall surface and quantify the presence of scratches or gouges.

10 REFERENCE

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

§192.619

Maximum allowable operating pressure: Steel or plastic pipelines.

[Effective Date: 03/12/21]

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure (MAOP) determined under paragraph (c), (d), or (e) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or updated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

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

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

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the Table 1 to paragraph (a)(2)(ii):

TABLE 1 TO PARAGRAPH (a)(2)(ii)

Class location	Installed before (Nov. 12 1970)	Factors, ¹ 2 segment --		
		Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3.....	1.4	1.5	1.5	1.5
4.....	1.4	1.5	1.5	1.5

¹For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

²For a component with a design pressure established in accordance with § 192.153(a) or (b) installed after July 14, 2004, the factor is 1.3.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
(i) Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
(ii) Onshore regulated gathering pipeline (Type C under § 192.9(d)) that first became subject to this part (other than § 192.612) on or after May 16, 2022	May 16, 2023, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(iii) Onshore transmission line that was a gathering pipeline not subject to this part before March 15, 2006.	March 15, 2006, or date pipeline becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
(iv) Offshore gathering lines.	July 1, 1976.	July 1, 1971.
(v) All other pipelines.	July 1, 1970.	July 1, 1965.

(4) The pressure determined by the operator to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with § 192.607, if applicable, and the history of the pipeline segment, including known corrosion and actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instances:

(1) An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(2) For any Type C gas gathering pipeline under §192.9 existing on or before May 16, 2022, that was not previously subject to this part and the operator cannot determine the actual operating pressure of the pipeline for the 5 years preceding May 16, 2023, the operator may establish MAOP using other criteria based on a combination of operating conditions, other tests, and design with approval from PHMSA. The operator must notify PHMSA in accordance with §192.18. The notification must include the following information:

- (i) The proposed MAOP of the pipeline;
- (ii) Description of pipeline segment for which alternative methods are used to establish MAOP, including diameter, wall thickness, pipe grade, seam type, location, endpoints, other pertinent material properties, and age;
- (iii) Pipeline operating data, including operating history and maintenance history;
- (iv) Description of methods being used to establish MAOP;
- (v) Technical justification for use of the methods chosen to establish MAOP; and
- (vi) Evidence of review and acceptance of the justification by a qualified technical subject matter expert.

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

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

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

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

[Amdt. 192-3, 35 FR 17659, Nov. 17, 1970; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976 with Amdt. 192-27A, 41 FR 47252, Oct. 28, 1976; Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; 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. 192-102, 71 FR 13289, Mar. 15, 2006; Amdt. 192-103, 71 FR 33402, June 9, 2006; RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008; Amdt 192-125, Oct. 1, 2019, Amdt 192-128, Amdt. 192-129, 86 FR 63294 Nov. 15, 2021]

GUIDE MATERIAL

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

- (b) Gathering lines constructed of non-listed (§192.7 and Appendix B to Part 192) materials may have an MAOP established by grandfather clause under §192.619(c).
- (c) When pipe segments with the following characteristics are considered for flow reversal or service conversion, caution should be exercised if pressure testing is planned.
 - (1) Grandfathered pipelines that operate without a Subpart J pressure test or where sufficient historical test or material strength records are not available.
 - (2) Low frequency electric resistance welded (LF-ERW) pipe, lap welded pipe, pipe with unknown seam types, and pipe with seam factors less than 1.0, as defined in §192.113.
 - (3) Pipelines with a history of failures and leaks, especially those due to stress corrosion cracking (SCC), internal or external corrosion, selective seam corrosion (SSC), or manufacturing defects.
 - (4) Pipelines that operate above Part 192 design factors (i.e., above 72% SMYS per §192.619(c)).
- (d) See Guide Material Appendices G-192-9, G-192-9A, and G-192-10.

§192.620

Alternative maximum allowable operating pressure for certain steel pipelines.

[Effective Date: 10/01/15]

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

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

Class Location	Alternative Design Factor (F)
1	0.80
2	0.67
3	0.56

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

(ii) [Reserved]

(2) The alternative maximum allowable operating pressure is the lower of the following:

(i) The design pressure of the weakest element in the pipeline segment, determined under subparts C and D of this part.

(ii) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction by a factor determined in the following table:

Class Location	Alternative Test Factor
1	1.25
2	¹ 1.50
3	1.50

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

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

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

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

- (1) For pipelines already in service, notify the PHMSA pipeline safety regional office where the pipeline is in service of the intention to use the alternative pressure at least 180 days before operating at the alternative MAOP. For new pipelines, notify the PHMSA pipeline safety regional office of planned alternative MAOP design and operation at least 60 days prior to the earliest start date of either pipe manufacturing or construction activities. An operator must also notify the state pipeline safety authority when the pipeline is located in a state where PHMSA has an interstate agent agreement or where an intrastate pipeline is regulated by that state.
- (2) Certify, by signature of a senior executive officer of the company, as follows:
 - (i) The pipeline segment meets the conditions described in paragraph (b) of this section; and
 - (ii) The operating and maintenance procedures include the additional operating and maintenance requirements of paragraph (d) of this section; and
 - (iii) The review and any needed program upgrade of the damage prevention program required by paragraph (d)(4)(v) of this section has been completed.

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

(4) For each pipeline segment, do one of the following:

(i) Perform a strength test as described in §192.505 at a test pressure calculated under paragraph (a) of this section or

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

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

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

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

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

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

<p>To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:</p>	<p>Take the following additional step:</p>
<p>(1) Identifying and evaluating threats</p>	<p>Develop a threat matrix consistent with §192.917 to do the following:</p> <ul style="list-style-type: none"> (i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and (ii) Describe and implement procedures used to mitigate the risk.
<p>(2) Notifying the public</p>	<ul style="list-style-type: none"> (i) Recalculate the potential impact circle as defined in §192.903 to reflect use of the alternative maximum operating pressure calculated under paragraph (a) of this section and pipeline operating conditions; and (ii) In implementing the public education program required under §192.616, perform the following: <ul style="list-style-type: none"> (A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and (B) Include information about the integrity management activities performed under this section within the message provided to the audience.
<p>(3) Responding to an emergency in an area defined as a high consequence area in §192.903</p>	<ul style="list-style-type: none"> (i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (d)(2)(i) of this section. (ii) If personnel response time to mainline valves on either side of the high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control. (iii) Remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream. (iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control.

<p>To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:</p>	<p>Take the following additional step:</p>
<p>(4) Protecting the right-of-way</p>	<p>(i) Patrol the right-of-way at intervals not exceeding 45 days, but at least 12 times each calendar year, to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline.</p> <p>(ii) Develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement.</p> <p>(iii) If observed conditions indicate the possible loss of cover, perform a depth of cover study and replace cover as necessary to restore the depth of cover or apply alternative means to provide protection equivalent to the originally-required depth of cover.</p> <p>(iv) Use line-of-sight line markers satisfying the requirements of §192.707(d) except in agricultural areas, large water crossings or swamp, steep terrain, or where prohibited by Federal Energy Regulatory Commission orders, permits, or local law.</p> <p>(v) Review the damage prevention program under §192.614(a) in light of national consensus practices, to ensure the program provides adequate protection of the right-of-way. Identify the standards or practices considered in the review, and meet or exceed those standards or practices by incorporating appropriate changes into the program.</p> <p>(vi) Develop and implement a right-of-way management plan to protect the pipeline segment from damage due to excavation activities.</p>
<p>(5) Controlling internal corrosion</p>	<p>(i) Develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents.</p> <p>(ii) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and gas quality monitoring equipment.</p> <p>(iii) Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling.</p> <p>(iv) Use cleaning pigs and sample accumulated liquids. Use inhibitors when corrosive gas or liquids are present.</p> <p>(v) Address deleterious gas stream constituents as follows: (A) Limit carbon dioxide to 3 percent by volume; (B) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and</p>

<p>To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:</p>	<p>Take the following additional step:</p>
<p>(5) Controlling internal corrosion (continued)</p>	<p>(C) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas, where the hydrogen sulfide is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points.</p> <p>(vi) Review the program at least quarterly based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.</p>
<p>(6) Controlling interference that can impact external corrosion</p>	<p>(i) Prior to operating an existing pipeline segment at an alternate maximum allowable operating pressure calculated under this section, or within six months after placing a new pipeline segment in service at an alternate maximum allowable operating pressure calculated under this section, address any interference currents on the pipeline segment.</p> <p>(ii) To address interference currents, perform the following:</p> <p>(A) Conduct an interference survey to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected;</p> <p>(B) Analyze the results of the survey; and</p> <p>(C) Take any remedial action needed within 6 months after completing the survey to protect the pipeline segment from deleterious current.</p>
<p>(7) Confirming external corrosion control through indirect assessment</p>	<p>(i) Within six months after placing the cathodic protection of a new pipeline segment in operation, or within six months after certifying a segment under §192.620(c)(1) of an existing pipeline segment under this section, assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG).</p> <p>(ii) Remediate any construction damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP-0502-2002 (incorporated by reference, see §192.7).</p> <p>(iii) Within six months after completing the baseline internal inspection required under paragraph (d)(9) of this section, integrate the results of the indirect assessment required under paragraph (d)(7)(i) of this section with the results of the baseline internal inspection and take any needed remedial actions.</p>

<p>To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:</p>	<p>Take the following additional step:</p>
<p>(7) Confirming external corrosion control through indirect assessment (continued)</p>	<p>(iv) For all pipeline segments in high consequence areas, perform periodic assessments as follows:</p> <p>(A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under subpart O of this part.</p> <p>(B) Locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area, if practicable.</p> <p>(C) Integrate the results with those of the baseline and periodic assessments for integrity done under paragraphs (d)(9) and (d)(10) of this section.</p>
<p>(8) Controlling external corrosion through cathodic protection</p>	<p>(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete remedial action within six months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service demonstrating that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State; and</p> <p>(ii) After remedial action to address a failed reading, confirm restoration of adequate corrosion control by a close interval survey on either side of the affected test station to the next test station unless the reason for the failed reading is determined to be a rectifier connection or power input problem that can be remediated and otherwise verified.</p> <p>(iii) If the pipeline segment has been in operation, the cathodic protection system on the pipeline segment must have been operational within 12 months of the completion of construction.</p>
<p>(9) Conducting a baseline assessment of integrity</p>	<p>(i) Except as provided in paragraph (d)(9)(iii) of this section, for a new pipeline segment operating at the new alternative maximum allowable operating pressure, perform a baseline internal inspection of the entire pipeline segment as follows:</p> <p>(A) Assess using a geometry tool after the initial hydrostatic test and backfill and within six months after placing the new pipeline segment in service; and</p> <p>(B) Assess using a high resolution magnetic flux tool within three years after placing the new pipeline segment in service at the alternative maximum allowable operating pressure.</p>

<p>To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:</p>	<p>Take the following additional step:</p>
<p>(9) Conducting a baseline assessment of integrity (continued)</p>	<p>(ii) Except as provided in paragraph (d)(9)(iii) of this section, for an existing pipeline segment, perform a baseline internal assessment using a geometry tool and a high resolution magnetic flux tool before, but within two years prior to, raising pressure to the alternative maximum allowable operating pressure as allowed under this section.</p> <p>(iii) If headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a pipeline segment operating at alternative maximum allowable operating pressure cannot accommodate a geometry tool and a high resolution magnetic flux tool, use direct assessment (per §192.925, §192.927 and/or §192.929) or pressure testing (per subpart J of this part) to assess that portion.</p>
<p>(10) Conducting periodic assessments of integrity</p>	<p>(i) Determine a frequency for subsequent periodic integrity assessments as if all the alternative maximum allowable operating pressure pipeline segments were covered by subpart O of this part and</p> <p>(ii) Conduct periodic internal inspections using a high resolution magnetic flux tool on the frequency determined under paragraph (d)(10)(i) of this section, or</p> <p>(iii) Use direct assessment (per §192.925, §192.927 and/or §192.929) or pressure testing (per subpart J of this part) for periodic assessment of a portion of a segment to the extent permitted for a baseline assessment under paragraph (d)(9)(iii) of this section.</p>
<p>(11) Making repairs</p>	<p>(i) Perform the following when evaluating an anomaly:</p> <p style="padding-left: 40px;">(A) Use the most conservative calculation for determining remaining strength or an alternative validated calculation based on pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature: and</p> <p style="padding-left: 40px;">(B) Take into account the tolerances of the tools used for the inspection.</p> <p>(ii) Repair a defect immediately if any of the following apply:</p> <p style="padding-left: 40px;">(A) The defect is a dent discovered during the baseline assessment for integrity under paragraph (d)(9) of this section and the defect meets the criteria for immediate repair in §192.309(b).</p> <p style="padding-left: 40px;">(B) The defect meets the criteria for immediate repair in §192.933(d).</p>

<p>To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:</p>	<p>Take the following additional step:</p>
<p>(11) Making repairs (continued)</p>	<p>(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.</p> <p>(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure.</p> <p>(iii) If paragraph (d)(11)(ii) of this section does not require immediate repair, repair a defect within one year if any of the following apply:</p> <p>(A) The defect meets the criteria for repair within one year in §192.933(d).</p> <p>(B) The alternative maximum allowable operating pressure was based on a design factor of 0.80 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.</p> <p>(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure.</p> <p>(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure.</p> <p>(iv) Evaluate any defect not required to be repaired under paragraph (d)(11)(ii) or (iii) of this section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.</p>

(e) *Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure?* Notwithstanding the required capacity of pressure relieving and limiting stations otherwise required by §192.201, if an operator establishes a maximum allowable operating pressure for a pipeline segment in accordance with paragraph (a) of this section, an operator must:

- (1) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and
- (2) Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

[Issued by RIN 2137-AE25, 73 FR 62148, Oct. 17, 2008; Eff. date stayed by 73 FR 72737, Dec. 1, 2008; Amdt. 192-111, 74 FR 62503, Nov. 30, 2009; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015]

GUIDE MATERIAL

1 SCOPE

This guide material applies to an alternative MAOP for new or existing steel pipelines. An alternative MAOP for an existing pipeline is applicable as follows.

- (a) Preventing a reduction of MAOP if the class location changes, or
- (b) Increasing MAOP, such as in response to a change in throughput.

To have an alternate MAOP, an existing pipeline is required to meet the design, construction, operations, and maintenance requirements in §192.620. Requirements differ for pipelines that are already in operation versus those that are newly constructed.

2 GENERAL

Certain pipelines or pipeline segments as listed below may not use an alternative MAOP (see §192.620(b)).

- (a) Pipeline segments in Class 4 locations.
- (b) Pipeline segments of a grandfathered pipeline already operating at a higher stress level, but not constructed in accordance with current requirements (see §192.620(c)(8)).
- (c) Pipeline segments with pipe that is bare or ineffectively coated (disbonded or otherwise shields CP current), which may not allow the cathodic protection (CP) to pass through the coating.
- (d) Pipelines that did not have CP installed within 12 months of initial operation.
- (e) Pipelines with wrinkle bends.
- (f) A pipeline with failures, such as seam failure during hydrostatic testing, unless a root cause or failure analysis (including metallurgical examination of the failed pipe) has determined the failure is not indicative of a systemic problem.
- (g) Pipeline segments with pipe manufactured by certain processes, such as low-frequency electric resistance welding, or pipe with a longitudinal joint factor less than 1 (see §192.113).
- (h) Pipeline segments that cannot accommodate internal inspection devices.
- (i) Pipelines constructed with used or reconditioned pipe.
- (j) Non-steel pipelines.
- (k) Pipelines not monitored and controlled by supervisory control and data acquisition (SCADA) systems.
- (l) Pipelines that have mechanical couplings in lieu of girth welds.
- (m) Pipelines transporting gas with a carbon dioxide content of more than 3 percent (see §192.620(d)). Blending should not be used to lower the carbon dioxide content.
- (n) Existing pipelines that do not meet the additional design requirements of §192.112, or the additional construction requirements of §192.328.
- (o) Existing pipelines that do not have at least 95 percent of the girth welds non-destructively tested.

3 ESTABLISHING AN ALTERNATIVE MAOP

- (a) Notification.
 - (1) Section 192.620(c)(1) requires that notification for in-service pipelines be provided to PHMSA and each applicable state pipeline safety agency at least 180 days before operating at the alternative MAOP. This section also requires notification of planned alternative MAOP design and operation for new pipelines at least 60 days prior to the start date of either pipe manufacturing or construction activities, whichever occurs first. Regulatory agencies may use this time for inspection of the facility, records, plans, and procedures.
 - (2) Notification should include the following.
 - (i) Operator name and ID number.
 - (ii) Pipeline name.
 - (iii) Location and simple map of the facility.

- (iv) Proposed MAOP of the facility.
 - (v) Existing MAOP, if the facility is already in use, and reason for changing MAOP.
 - (vi) Other involved facilities, such as compressor stations or regulator stations.
- (3) Early notification might help avoid delays by allowing PHMSA time to review the procedural manual, specifications, pipe manufacturing records, external coating, field construction activities, Operator Qualification (OQ) program, and other documentation.
- (4) The advance notification might not be considered complete until all required documentation has been received by PHMSA. Notification should be considered complete when confirmation is received by the operator.
- (5) Section 192.620(c) requires that additional certification be submitted at least 30 days before the pipeline can operate at the higher MAOP. The 30-day notification requires certification by a senior executive officer that the pipeline meets the requirements for alternative MAOP operation, which include the following.
- (i) Changes to operating and maintenance (O&M) procedures for the more rigorous and additional O&M requirements.
 - (A) Right-of-way (ROW) management plans.
 - (B) Depth-of-cover maintenance program.
 - (C) Site-specific external and internal corrosion plans.
 - (D) Integrity assessment plans.
 - (E) Repair criteria.
 - (ii) Changes to the damage prevention program, which includes ensuring that the program meets or exceeds Common Ground Alliance (CGA) or equivalent best practices.
 - (iii) Changes to the OQ program to ensure that construction tasks are covered.
 - (iv) Identification and assessment of threats.
 - (v) Changes to the public awareness program.
 - (vi) Changes to emergency plans to address the additional needs of responding to emergencies at higher operating stress levels.
 - (vii) Required SCADA monitoring and control is in place.
- (b) Calculating MAOP.
- (1) Alternative MAOP is established based upon design and test factors prescribed in §192.620(a), which are listed below.

Class Location	Alternative Design Factor	Stress level	Alternative Test Factor
1	0.80	80%	1.25
2	0.67	67%	1.50 ¹
3	0.56	56%	1.50
4	NA	NA	NA

¹ For segments installed prior to December 22, 2008, test factor is 1.25.

Table 192.620i

- (2) Alternative design factors for road crossings, fabrications, headers, mainline valve assemblies, separators, meter stations, and compressor stations are available for existing facilities, and can only be used on existing facilities for confirmation at the higher MAOP.
- (3) If operators design road/railroad crossings, fabrications, headers, mainline valve assemblies, separators, meter stations, and compressor stations on new pipelines operating under an alternative MAOP in accordance with the design factors in 49 CFR §192.111(b), (c), or (d), then these short segments of pipelines or facilities will not be operating at an alternative MAOP and are not subject to the alternative MAOP regulation.

4 ADDITIONAL OPERATION AND MAINTENANCE REQUIREMENTS

- (a) General. There are additional operating and maintenance requirements that are intended to address certain risks for gas pipelines, such as excavation damage and corrosion. These include requirements for an operator to evaluate and address the issues associated with operating at higher pressures. Section 192.620(c)(2)(ii) requires that the operator make the necessary changes to their O&M procedures to include the requirements in §192.620(d) before commencing operation at an alternative MAOP.
- (b) Identifying and evaluating threats. Some provisions of §192.620(d) are more restrictive than Subpart O. The Regulations address many known threats, however, other threats may exist or develop that affect the pipeline integrity. It is up to the operator to identify and evaluate possible pipeline threats in accordance with ASME B31.8S (see listing in §192.7, not IBR for §192.620). To address the comparison of conventional MAOP to the risk of an alternative MAOP pipeline, the operator should develop a risk ranking that identifies and compares the increased risk.
- (c) Notifying the public (§192.620(d)(2)). Additional public information is necessary to inform any stakeholders living along the ROW. At a minimum, the public notification includes either the 220-yard corridor required for class location, or the calculated potential impact radius (PIR) for the segment, whichever is the greater distance. An operator should consider adding additional footage to these distances.

Some activities performed as requirements for public awareness may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.616, and 192.935.

- (1) An operator may want to review the messages sent to stakeholders along an alternative MAOP pipeline to ensure the special nature of the pipeline is addressed. The messages should include the MAOP and product type, additional O&M activities and inspections, and the additional integrity requirements. This may require different types of communication, including social media.
- (2) Where the alternative MAOP pipeline is in a High Consequence Area (HCA) already identified per Subpart O, then no additional notification may be necessary beyond that required under Subpart O.
- (3) An operator may want to consider more frequent evaluations for effectiveness on alternative MAOP pipelines.
- (d) Responding to an emergency in HCAs. While additional response measures are required for HCAs, the operator may choose to incorporate these additional requirements beyond the HCA limits. The operator should maintain a list of response times based on actual driving of the route. The operator may want to consider the following.
 - (1) Reviewing response time from the normal daytime crew departure location.
 - (2) Reviewing response time during non-working hours for first responders.
 - (3) Altering the responding location if drive times are not within required limits.
 - (4) Periodically reviewing response time to determine if any significant changes to roads or driving conditions might alter response times.
- (e) Protecting the right-of-way (§192.620(d)(4)). The operator must have a written plan to address ROW protection. Operators may already address ROW protection and soil monitoring issues in their damage prevention, continuing surveillance, patrolling, or other O&M procedures, such that an additional plan may not be required. To protect from outside force damage, the operator must maintain the pipeline depth of cover. If observed conditions indicate a loss of cover, the operator is required to perform a depth-of-cover study and replace the cover or remediate by alternative methods (§192.620(d)(4)(iii)). Alternative protection must provide equivalent protection and the operator must demonstrate this equivalence.
 - (1) Transmission pipelines are often located in areas such as hills and mountainous terrain, which can exhibit unstable soils, (e.g., clay). It is important to ensure that stresses caused by soil movement do not damage pipelines in these areas with reduced design safety factors.

- (2) Plans should include how an operator will address the various environmental or geologic conditions that might affect the pipeline.
- (3) Other considerations for protecting the ROW might include an annual review for possible loss of cover. This can be accomplished by reviewing patrolling and continuing surveillance records, one-call records, or other means of monitoring areas that have the potential for loss of cover.
- (4) Actual field survey for depth of cover should be done periodically. Some methods of performing depth-of-cover survey include the following.
 - (i) Barring or probing the line.
 - (ii) Using line locating equipment.
 - (iii) Using survey and in-line inspection (ILI) GPS data.
 - (iv) Using current attenuation surveys.
 - (v) Other methods.
- (5) The operator may choose to develop a written procedure to document that missing line markers will be detected and replaced. Due to the inherent hazards of the alternative MAOP pipelines, a more frequent marker check and replacement program may be appropriate. The operator should document all removed, repaired, and replaced pipeline markers. The operator should also document areas where line markers are not placed within line-of-sight, and the justification for the lack of additional markers.
- (6) The operator should review national consensus standards such as CGA, implement the applicable best practices into their written procedures, and provide written justification, as appropriate, for not implementing these practices.
- (f) Controlling external corrosion (§192.620(d)(6), (7), and (8)). Two levels of protection are required against the corrosion threat: coating and CP. These requirements are intended to provide redundant protection. If coating fails, CP continues to protect the pipe. If CP fails, the coating is still present.
 - (1) The operator must conduct surveys capable of detecting the effect of interfering currents, but these surveys need not measure "current" directly. The operator should establish limits for interference remediation. In deciding where surveys are needed, the operator should consider the proximity of potential sources of interference, including the following.
 - (i) Electric transmission lines.
 - (ii) Other CP systems.
 - (iii) Foreign pipelines.
 - (iv) Electric railways.
 - (2) The operator should establish a plan to address interference currents, including periodic readings, testing requirements, and appropriate remediation. The operator should follow the requirements of NACE SP0169.
 - (3) Operators can delay the start of operation at an alternative MAOP if they cannot schedule coating surveys within six months. Coating adequacy is important for existing pipelines as well as new construction. ILI or other assessments are a second level of defense by detecting corrosion after it occurs, and should not be considered as an alternative for prevention.
 - (4) Test stations must be located at half-mile intervals within an HCA with at least one test station within the HCA if practicable (§192.620(d)(7)(iv)(B)). The operator should document cases where this spacing is impracticable.
 - (5) Low CP readings must be addressed within 6 months. The operator should verify the remediation was adequate by performing an electrical survey around the low reading (§192.620(d)(8)(i)).
 - (6) Operators must notify the PHMSA regional office where a pipeline is located (and applicable state pipeline safety agency) if inadequate CP readings are not addressed within six months, providing the reason for the delay and a justification that the delay is not detrimental to pipeline safety. Operators have the discretion to determine the corrective action and must verify that corrective action is adequate (§192.620(d)(8)(i)).
- (g) Additional design requirements (§192.620(b)(2)). Compressor station discharge temperature is limited to 120 °F, except as provided by §192.112(h)(2) and (3), which allow operation above this temperature if research, testing, and field monitoring tests demonstrate that the coating type being used will withstand long-term operation at the higher temperature. The operator must assemble and

maintain the data supporting higher-temperature operation. For temperatures exceeding 120 °F, operators must establish a long-term coating integrity monitoring program (§192.112(h)(3)). In addition, a monitoring program could include the following.

- (1) Maximum limits for temperatures and the basis for those maximum limits. (In general, an operator should limit operating temperatures of FBE coated pipe to no greater than 150 °F under all circumstances.) The operator should install gas coolers to limit compressor station discharge temperatures if maximum limits could be exceeded.
 - (2) Temperature monitoring at the compressor station and along the pipeline to identify where pipe and coating temperatures could exceed 120 °F. If "real time" continuous temperature monitoring at the furthest point down the pipeline where the temperature might exceed 120 °F is not provided, the operator must demonstrate that the approach to periodically monitor temperatures will ensure that any location above 120 °F will be promptly identified.
 - (3) Monitor and record the actual operating temperatures in the segments operating under alternative MAOP rule for the life of the pipeline.
 - (4) Conduct coating performance surveys using either direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG) to monitor coating conditions and identify coating holidays. These coating surveys should include a baseline survey, one-year survey, 3-year survey, and 7-year survey to identify poor coating performance. If ILI surveys and these DCVG or ACVG surveys show coating deterioration, ILI intervals need to be decreased accordingly. All coating holidays or other issues indicative of deteriorating coating quality identified from these surveys must be promptly remediated.
 - (5) A long-term coating integrity monitoring program can be used as a basis for allowing pipe temperatures in excess of 120 °F. Operators must submit their programs to the PHMSA regional office in which the pipeline is located for review before pipeline segments may be operated at alternative MAOP at these higher temperatures. The monitoring programs must be comprehensive enough to ensure long-term coating integrity, to identify instances in which coating integrity becomes degraded, and to address those problems. Operators should consider installing gas coolers at compressor stations, or as an alternative, installing heavier-wall pipe operating at a conventional MAOP for the distance downstream of a compressor station to ensure that the pipe wall temperature does not exceed 120 °F.
- (h) Controlling internal corrosion (§192.620(d)(5)). An operator should develop a written internal corrosion plan specific to each alternative MAOP pipeline. The operator should include information such as pipeline configuration, low points or drop-out locations, liquid removal locations, receipt points, partial pressures of corrosive constituents, monitoring program and related sampling intervals, use of cleaning pigs, and use of inhibitors or biocides. The plan should also include action thresholds, and types of remedial actions to be taken. For internal corrosion control, see guide material under §§192.475 and 192.476.
- (1) Monitoring programs can include the use of internal corrosion coupons at strategic points, gas quality monitoring, liquid sampling, sampling of pigging products, or other methods of internal corrosion monitoring. Deleterious gas stream constituents also include entrained or suspended solids (regardless of size) that are detrimental to the pipeline or pipeline facilities. The operator should modify internal pipe inspection procedures to include sampling of all products that might be found if the pipeline is cut open.
 - (2) Operators can rely on others (e.g., those supplying gas) to perform monitoring, but must ensure that such monitoring covers all gas streams and meets the requirements of §192.620(d)(5), including the need for continuous monitoring.
- (i) Overpressure protection (§192.620(e)(1)). The overpressure protection limit is reduced to a maximum of 104 percent of MAOP. The operator may choose not to set initial alarms or overpressure protection devices above the MAOP. Redundant systems are recommended. Excursions above MAOP should be documented as an abnormal operation.

5 INTEGRITY MANAGEMENT REQUIREMENTS

- (a) Direct assessment methods (e.g., close interval survey (CIS), DCVG) must be used for periodic assessment (§192.620(d)(7)(iv)). An operator may want to modify pipe inspection reports required

- by §192.459 to provide additional data for analysis.
- (b) An operator must consider tool tolerances and accuracy when scheduling remediation response (§192.620(d)(11)(i)(B)). An operator should retain the documentation and justification for the values used, which may include unity plots. Under-calling defects may necessitate regrading of the tool run.
 - (c) The operator should apply additional restrictions for direct assessment pipe examinations for internal or external corrosion, or SCC, including detailed measurements, nondestructive examination (NDE), and characterization of the defect or anomaly.
 - (d) The operator should adjust reporting thresholds to ensure that small defects are identified for analysis.
 - (e) Existing repair criteria should account for smaller-type defects and faster repair times.
 - (f) The operator should have a method to communicate the results of dig inspections back to the ILI vendor for confirming and improving accuracy of the ILI data and improving vendor algorithms for data analysis.
 - (g) The operator must integrate all results, including ILI data, external corrosion data and surveys, internal corrosion data, depth-of-cover data, and other data as appropriate for analyzing threats and risks (§192.620(d)(7)(iii)).
 - (h) The operator must define action thresholds, such as immediate or one-year, based on design criteria and calculated failure pressures (§192.620(d)(11)).

Note: Although PHMSA updated the incorporated-by-reference standard in §192.7 from NACE RP-0502-2002 to NACE SP0502-2010 under Amendment 192-119, §192.620(d)(7)(ii) was not updated

6 HIGH YIELD PIPELINES (GENERALLY GRADE X-70 OR ABOVE)

- (a) Operators should perform ILI that will identify threats to the pipeline.
 - (1) The operator should use a high-resolution deformation tool in lieu of a geometry tool.
 - (2) The deformation tool is to include multi-finger sensors and have an accuracy of +/- 1 percent to identify expanded pipe and dents.
- (b) The results of the initial ILI must be integrated with the initial CIS and any DCVG or ACVG surveys required by §192.620, as well as other data, such as patrolling and depth-of-cover surveys (§192.620(d)(7)(iii)).
- (c) The operator must evaluate and remediate anomalies (e.g., expanded pipe, dents) prior to increasing the pressure above 72 percent SMYS for Class 1 locations (see §192.620(c)(2)(ii) and (c)(5)).
 - (1) The results of deformation and geometry tool runs for expanded pipe and dents should be analyzed and submitted to the PHMSA Regional Director.
 - (2) All pipe exhibiting an indicated diameter greater than 1 percent above the nominal pipe diameter should be noted on the report of potential deformations.
 - (3) Analysis should consider pipe properties and property distributions, hydrostatic test pressures and reported test behavior, and pipe end-to-center variations. Based on local pressure and expected behavior, any expansion exceeding anticipated expansion by more than 1.5 percent should be investigated by excavation to determine actual expansion.
 - (4) An operator should take appropriate action in accordance with OPS Advisory Bulletin ADB-10-03 for examination of potential problems with misalignment, improper transitioning, improper back welds, cut factory bends, improper support of pipe and appurtenances, and other construction issues.

7 DENT REPAIRS

Certain pipeline dents must be repaired in order to operate pipelines at stress levels allowed under the alternative MAOP rule as follows.

- (a) The repair criteria in §192.620(d)(11)(ii) require that dents in existing lines implementing alternative MAOP must be repaired if they meet criteria in either §192.309(b) or §192.933(d)(1) or (2). This is intended to ensure that existing pipelines operated at stress levels allowed by the alternative MAOP rule are in "like new" condition with respect to dent defects.
- (b) The operator should review the deformation/geometry tool reports and consider the following

information.

- (1) Pipe properties and property distributions from tests.
 - (2) Test pressures and reported test behavior from hydrostatic tests.
 - (3) Pipe end-to-center diameter variations.
- (c) Inspections for low-strength pipe and any pipe repair/removal must be completed prior to operating the pipeline to an alternative MAOP (§192.620(c)(8)).

8 REFERENCES

- (a) Alternative MAOP FAQs by PHMSA-OPS available at <http://primis.phmsa.dot.gov/maop/faqs.htm>.
- (b) "Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Gas Pipelines," available at <http://primis.phmsa.dot.gov/lowstrength/docs/InterimGuidelinesGas.pdf>.
- (c) OPS Advisory Bulletin ADB-10-03 (75 FR 14243, Mar. 24, 2010; see Guide Material Appendix G-192-1, Section 2).

§192.621

Maximum allowable operating pressure: High-pressure distribution systems.

[Effective Date: 07/13/98]

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.

(2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i.g., unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of §192.197(c).

(3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.

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

(5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a) (5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

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

GUIDE MATERIAL

For high-pressure distribution systems containing steel or plastic pipelines, see §192.619.

§192.623

Maximum and minimum allowable operating pressure: Low-pressure distribution systems.

[Effective Date: 04/26/96]

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

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

[Amdt. 192-75, 61 FR 18512, Apr. 26, 1996 with Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996]

GUIDE MATERIAL

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

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

§192.624

Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines.

[Effective Date: 07/01/2020]

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

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

- (i) A high consequence area as defined in § 192.903; or
- (ii) A Class 3 or Class 4 location.

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

- (i) A high consequence area as defined in § 192.903; or
- (ii) A Class 3 or Class 4 location; or
- (iii) A moderate consequence area as defined by § 192.3, if the pipeline segment can accommodate inspection by means of instrumented inspection inline tools.

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

(1) Operators must complete all actions required by this section on at least 50% of the pipeline mileage by July 3, 2028.

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

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

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

(1) *Method 1: Pressure test.* Perform a pressure test and verify material property records in accordance with § 192.607 and the following requirements:

(i) *Pressure test.* Perform a pressure test in accordance of subpart J of this part. The MAOP must equal to the test pressure divided by the greater of either 1.25 or applicable class location factor in § 192.619(a)(2)(ii).

(ii) *Material properties records.* Determine if the following material properties records are documented in traceable, verifiable, and complete records. Diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength).

(iii) *Material properties verification.* If any of the records required by paragraph (c)(1)(ii) are not documented in traceable, verifiable, and complete records the operator must obtain the missing records in accordance with § 192.607. The operator must test the pipe materials cut out from the test manifold sites at the time the pressure test is conducted. If there is a failure during a pressure test, the operator test any removed pipe from the pressure test failure in accordance with § 192.607.

(2) *Method 2: Pressure Reduction.* Reduce pressure as necessary, and limit MAOP to no greater than the highest actual operating pressure sustained by the pipeline during the 5 years preceding October 1, 2019, divided by the greater of 1.25 or applicable class location factor in § 192.619(a)(2)(ii). The highest actual sustained pressure must have been reached for a minimum cumulative of 8 hours during a continuous 30-day period. The value used at the highest actual sustained operating pressure must account for differences between upstream and downstream pressure on the pipeline by use of either the lowest maximum pressure value for the entire pipeline segment or using the operating pressure gradient along the entire pipeline segment (i.e., the location specific operating pressure at each location).

(i) Where the pipeline segment has had a class location change in accordance with § 192.611, and records documenting diameter, wall thickness, seam type, and grade (minimum yield strength, ultimate tensile strength), and pressure tests are not documented in traceable, verifiable, and complete records, the operator must reduce the pipeline segment MAOP as follows:

[A] For pipeline segments where a class location changed from Class 1 to Class 2, from Class 2 to Class 3, or from Class 3 to Class 4, reduce the MAOP to no greater than the highest actual operating pressure sustained during the 5 years preceding October 1, 2019, divided by 1.39 for Class 1 to Class 2, 1.67 for Class 2 to Class 3, and 2.00 for Class 3 to Class 4

[B] For pipeline segments where a class location changed from Class 1 to Class 3, reduce the MAOP to no greater than the highest actual operating pressure sustained during the 5 years preceding October 1, 2019, divided by 2.00.

(ii) Future uprating of the pipeline segment in accordance with subpart K is allowed if the MAOP is establish using Method 2.

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

- (A) Descriptions of the operational constraint, special circumstances, or other factors that preclude or make it impracticable, to use the pressure reduction factor specified in § 192.624(c)(2);
- (B) The fracture mechanics modeling for failure stress pressures and cyclic fatigue crack growth analysis that complies with § 192.712;
- (C) Justification that establishing MAOP by another method allowed by this section is impracticable;
- (D) Justification that the reduced MAOP determined by the operator is safe based on analysis of the condition of the pipeline segment, including material property records, material properties verified in accordance with § 192.607, and the history of the pipeline segment, particularly known corrosion and leakage, and the actual operating pressure, and additional compensatory preventive and mitigative measures taken or planned; and
- (E) Planned duration for operating the requested MAOP, long-term remediation measures and justification of this operating time interval, including fracture mechanics modeling for failure stress pressure and cyclic fatigue growth analysis and other validated forms of engineering analysis that have been reviewed and confirmed by subject matter experts.

(3) *Method 3: Engineering Critical Assessment (ECA).* Conduct an ECA in accordance with § 192.632.

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

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

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

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

TABLE 1 to § 192.624(c)(5)(ii)

Class locations	Patrols	Leakage surveys
(A) Class 1 and Class 2	3 1/2 months, but at least four times each calendar year.	3 1/2 months, but at least four times each calendar year.
(B) Class 3 and Class 4	3 months, but at least six times each calendar year.	3 months, but at least six times each calendar year.

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

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

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

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

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

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

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

(vi) Operational monitoring procedures

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

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

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

GUIDE MATERIAL

1 GENERAL

This section applies to onshore steel transmission pipeline segments. MAOP reconfirmation is also applicable to transmission line pipe and non-line pipe components within appurtenant facilities including compressor, meter, and pressure limiting stations. MAOP reconfirmation is required (§192.624(a)) for pipeline segments with non-TVC MAOP records located within the following areas.

Applicability	Pipeline Location
MAOP Records (§ 192.619(a)(2)) not Traceable, Verifiable, and Complete (TVC)	High Consequence Area
	Class 3 Location
	Class 4 Location
Pipelines with MAOP Grandfathered by §192.619(c) and ≥ 30% SMYS	High Consequence Area
	Class 3 Location
	Class 4 Location
	Moderate Consequence Area and ILI-capable

(a) Traceable, Verifiable, and Complete (TVC) Records Considerations – Operators may consider the following definitions that are taken from the PHMSA preamble to the Final Rule of Amendment 192-125:

- (1) Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, which include mechanical and chemical properties; purchase requisition; or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter. Careful attention should be given to records transcribed from original documents as they may contain errors. Information from a transcribed document, in many cases, should be verified with complementary or supporting documents.
- (2) Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a pipeline segment complemented by pressure charts or field logs. Another

example might include a purchase order to a pipe mill with pipe specifications verified by a metallurgical test of a coupon pulled from the same pipeline segment. In general, the only acceptable use of an affidavit would be as a complementary document, prepared and signed at the time of the test or inspection by a qualified individual who observed the test or inspection being performed.

- (3) Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking such as a corporate stamp or seal. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable. An incomplete record might reflect that the pressure test was initiated, failed and restarted without conclusive indication of a successful test. A record that cannot be specifically linked to an individual pipeline segment is not a complete record for that segment. Incomplete or partial records are not an adequate basis for establishing MAOP or MOP. If records are unknown or unknowable, a more conservative approach is indicated.
- (4) A single record may be confirmed as being TVC.
- (5) Pressure test records must meet the requirements of § 192.619(a)(2).
- (b) For pipelines that have TVC test records in accordance with §192.619(a)(2), but tested prior to July 1, 1965, the confirmed MAOP is restricted to §192.619(a)(3) (the lowest of §192.619(a)).

2 PROCEDURES AND COMPLETION DATES

- (a) Operators will be required to report annual MAOP reconfirmation progress to PHMSA as part of the annual submittal of Form F 7100.2-1 (PHMSA Annual Report for Natural and Other Gas Transmission and Gathering Pipeline Systems).
- (b) If a pipeline segment requires MAOP reconfirmation due to a change in location class, then operators must confirm or revise the MAOP for that segment within 24 months. This follows §§192.609 and 192.611 timeframes.

3 RECONFIRMATION METHODOLOGIES – CLARIFICATIONS AND CONSIDERATIONS

- (a) Method 1 – Pressure Test.
If any of the records are not TVC, then missing records must be obtained and/or material attributes verified in accordance with § 192.607 (§192.624(c)(1)).
- (b) Method 2 – Pressure Reduction.
The minimum cumulative duration of eight hours where the highest actual sustained pressure must have been reached during the continuous 30-day period (§192.624(c)(2)). The eight-hour period does not need to be continuous; it can be made up of shorter periods that over the course of 30 days amount to at least eight hours above a certain pressure. Sustained pressure may be substantiated using operator's pressure logs for the pipeline (e.g., SCADA data, pressure measurement points).
- (c) Method 3 – Engineering Critical Assessment (ECA).
 - (1) Operators should consider developing procedures on how to conduct an ECA within their organization.
 - (2) Examples of technically proven models for calculating predicted failure pressures include those listed below. Other methods must use a technically proven fracture mechanics model appropriate to the failure mode, material properties, and boundary condition used (pressure test, ILI) (§192.632).
 - (i) Brittle Failure.
 - (A) Newman-Raju Model
 - (B) PipeAssess PI™
 - (ii) Ductile Failure.
 - (A) Modified Log-Secant Model
 - (B) API 579 – Level II or Level III
 - (C) CorLas™

- (D) PAFFC Model
- (E) PipeAssess PI™
- (3) See guide material under §192.632.
- (d) Method 4 – Pipe Replacement.
- (e) Method 5 – Pressure Reduction for Pipeline Segments with Small Potential Impact Radius (PIR).
The minimum cumulative duration of eight hours where the highest actual sustained pressure must have been reached during the continuous 30-day period (§192.624(c)(5)). The eight-hour period does not need to be continuous; it can be made up of shorter periods that over the course of 30 days amount to at least eight hours above a certain pressure. Sustained pressure may be substantiated using operator’s pressure logs for the pipeline (e.g., SCADA data, pressure measurement points).
- (f) Method 6 – Alternative Technology.
If no response is provided by PHMSA within the 90-day timeframe subsequent to notification, then operators may proceed with the use of the alternative technology (§192.18).
- (g) Operators should consider developing a process or decision matrix for reconfirmation method selection and pipeline segment prioritization. The following factors should be considered in the development.
 - (1) History of the pipeline segment and current pipeline conditions.
 - (2) Reliability and resiliency of the impacted pipeline network.
 - (3) Ability to take a pipeline out of service for pressure testing (feasibility of Method 1).
 - (4) Pressure reduction impacting the ability to run an in-line inspection (ILI) tool (feasibility of Methods 2 and 5).
 - (5) Ability to accommodate the passage of an ILI tool or availability of assessment tools (feasibility of Method 3).
 - (6) Constructability (e.g., pipeline accessibility, permitting).
 - (7) Impact to customers, the public, and the environment (e.g., service interruptions, sensitive areas).
 - (8) Cost management.
 - (9) Specific PHMSA requirements (e.g., deadlines).

4 RECORDS

Records for abandoned pipelines do not need to be retained.

§192.625 Odorization of gas.

[Effective Date: 10/15/03]

- (a) A combustible gas in a distribution line must contain a natural odorant or be odorized so that at a concentration in air of one-fifth of the lower explosive limit, the gas is readily detectable by a person with a normal sense of smell.
- (b) After December 31, 1976, a combustible gas in a transmission line in a Class 3 or Class 4 location must comply with the requirements of paragraph (a) of this section unless:
 - (1) At least 50 percent of the length of the line downstream from that location is in a Class 1 or Class 2 location;
 - (2) The line transports gas to any of the following facilities which received gas without an odorant from that line before May 5, 1975;
 - (i) An underground storage field;
 - (ii) A gas processing plant;
 - (iii) A gas dehydration plant; or
 - (iv) An industrial plant using gas in a process where the presence of an odorant:
 - (A) Makes the end product unfit for the purpose for which it is intended;

(B) Reduces the activity of a catalyst; or

(C) Reduces the percentage completion of a chemical reaction;

(3) In the case of a lateral line which transports gas to a distribution center, at least 50 percent of the length of that line is in a Class 1 or Class 2 location; or

(4) The combustible gas is hydrogen intended for use as a feedstock in a manufacturing process.

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

(1) The odorant may not be deleterious to persons, materials, or pipe.

(2) The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.

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

(e) Equipment for odorization must introduce the odorant without wide variations in the level of odorant.

(f) To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable. Operators of master meter systems may comply with this requirement by —

(1) Receiving written verification from their gas source that the gas has the proper concentration of odorant; and

(2) Conducting periodic "sniff" tests at the extremities of the system to confirm that the gas contains odorant.

[Amdt. 192-2, 35 FR 17335, Nov. 11, 1970; Amdt. 192-6, 36 FR 25423, Dec. 31, 1971; Amdt. 192-7, 37 FR 17970, Sept. 2, 1972; Amdt. 192-14, 38 FR 14943, June 7, 1973; Amdt. 192-15, 38 FR 35471, Dec. 28, 1973; Amdt. 192-16, 39 FR 45253, Dec. 31, 1974; Amdt. 192-21, 40 FR 20279, May 9, 1975; Amdt. 192-58, 53 FR 1633, Jan. 21, 1988; Amdt. 192-76, 61 FR 26121, May 24, 1996 with Amdt. 192-76 Correction, 61 FR 36825, July 15, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

1 GATHERING LINES

Operators of Type A gathering lines must evaluate the need for odorization according to §192.625(b) (§192.9(c)). Type B gathering lines are exempt from odorization requirements (§192.9(d)).

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

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

3 PERIODIC SAMPLING (§192.625(f))

3.1 Sites.

(a) Sampling sites should be selected to ensure that all gas within the piping system contains the required odorant concentration. The number of sites selected depends upon the size and configuration of the system, location of gate stations and locations suspected of low odorant level within the system.

(b) Consider the need for additional sampling sites when portable compressed natural gas (CNG) is temporarily introduced into the pipeline system. The type of processes used to produce CNG may cause the odorant level in the CNG to be reduced.

3.2 Frequency.

The testing should be performed at sufficiently frequent intervals to ensure that the gas is odorized to the required level.

3.3 Tests.

(a) Odor concentration tests should be conducted by personnel having a normal sense of smell and trained in the operation and use of odor concentration meters and procedures. A reference for determining odor intensity of natural gas is ASTM D6273.

(b) Sniff tests are qualitative tests that should be performed by individuals with a normal sense of smell. Such tests should be conducted by releasing small amounts of gas for a short duration in a

controlled manner to determine whether odorant is detectable.

- (c) A normal sense of smell may be affected by smoking, eating spicy foods, chewing tobacco or gum, or the presence of other strong odors. It may also be affected by health-related conditions, such as a head cold, that may interfere with the sense of smell. Prolonged or repetitive exposure to gas should be avoided because the sense of smell will fatigue with extended exposure to odorant.
- (d) A program should be considered to periodically check personnel who perform odorant sampling to verify that they possess normal olfactory senses.
- (e) A chemical analysis instrument (e.g., gas chromatograph) may be used to support or supplement odorant level information. If a chemical analysis instrument is used, the operator should periodically validate the measured odorant concentration with the proper concentration, which must be determined separately in accordance with paragraph (a) above.

3.4 *Records.*

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

4 ODOR INTENSITY IN PIPELINES

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

5 ODORANTS IN PLASTIC PIPELINES

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

6 SPECIAL CONSIDERATIONS

Operators should evaluate odorization requirements when transmission lines are subject to flow reversal.

7 REFERENCES

- (a) AGA XQ0005, "Odorization Manual."
- (b) ASTM D6273, "Standard Test Methods for Natural Gas Odor Intensity."

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§192.627

Tapping pipelines under pressure.

[Effective Date: 11/12/70]

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

GUIDE MATERIAL

1 PERSONNEL QUALIFICATIONS

- (a) Personnel performing hot taps should be:
 - (1) Familiar with the pressure limitations of the hot tapping equipment to be used; and
 - (2) Thoroughly trained in the mechanical procedures and safety precautions associated with the use of such equipment.
- (b) Operators should consider using their Operator Qualification Program to establish tapping qualification criteria and documentation requirements for an individual's qualification.
- (c) Although not required, operators of Type B gathering lines should consider the need for qualified personnel while performing hot taps on existing pipelines.

2 IDENTIFICATION OF PIPE

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

2.1 Before tapping.

- (a) Maps and records. The operator should thoroughly review applicable maps and records and contact the operators of other underground facilities (e.g., one-call system) to determine the location of other lines that may be in the vicinity of the pipeline to be tapped.
- (b) Exposed pipe. The following factors may be used to ensure that the exposed pipe is the one to be tapped. When identification of the pipe is uncertain, the operator should consider extending the excavation.
 - (1) Outside diameter.
 - (2) Longitudinal weld characteristics.
 - (i) Electric resistance weld.
 - (ii) Electric flash weld.
 - (iii) Electric fusion/submerged arc weld.
 - (iv) Spiral weld.
 - (v) Seamless.
 - (vi) Other weld characteristics.
 - (3) Coating.
 - (i) Coal tar.
 - (ii) Asphalt.
 - (iii) Wax.
 - (iv) Thin-film.
 - (v) Tape.
 - (vi) Extruded mastic or similar material.
 - (vii) Other coating materials.
 - (viii) Bare.

- (4) Material.
 - (i) Steel.
 - (ii) Cast iron.
 - (iii) Plastic.
 - (iv) Non-industry proprietary pipe.
 - (5) Joint connections.
 - (i) Welded.
 - (ii) Mechanically coupled.
 - (iii) Threaded.
 - (iv) Bell and spigot (lead, cement, or other) joint.
 - (v) Fused.
 - (vi) Solvent cement.
 - (vii) Other.
 - (6) Manufacturers markings.
 - (7) Color.
 - (8) Surface finish.
 - (9) Pipe-to-soil potential (off/on rectifier, test leads, and bonds).
 - (10) Wall thickness (ultrasonic).
 - (11) Pipe temperature.
- (c) Unexposed pipe. The following may be used to further ensure identification of the pipe to be tapped.
- (1) Pipe locator tracing.
 - (2) Probing.
 - (3) Above-ground indications of other buried facilities, such as markers, valve settings, backfill, and painted fence posts.
 - (4) Field alignment.

2.2 *During tapping.*

During the tapping procedure, the operator should address the following.

- (a) On initial line perforation:
 - (1) Verify pressure.
 - (2) Verify line contents, such as odorized gas, oil, gasoline, or water.
- (b) Inspect recovered coupon.

2.3 *Special considerations for casings and insertions.*

The operator should check for the presence of vents that would indicate the existence of a casing. If observations (e.g., records, vents, variance in diameter) indicate the possibility of a casing or insertion, the operator should consider radiography or checking for the existence of a depressured annulus (with tapping machine or by other means).

3 **SUITABILITY FOR TAPPING**

The operator should consider the following to determine the suitability of the pipe and the proposed location for tapping.

- (a) Inspect pipe for external corrosion.
- (b) Determine internal defects with ultrasonic meter or radiography.
- (c) Verify proper tap / seam / joint relationships.
- (d) Verify tapping equipment and materials are correct for intended pressure service.
- (e) Determine the proximity to regulators, valves, relief valves, meters, and other equipment that might be affected by metal shavings or other materials that are deposited into a pipeline during tapping operations. When in close proximity, the operator should consider using a magnetic sweep to collect metal shavings or installing a filter or screen. See §192.739(a)(4) for additional information.

4 **LOW-HYDROGEN WELDING**

Consideration should be given to the use of a low-hydrogen welding procedure when welding on a steel pipeline in service where the flow of gas or the metal thickness does not allow for maintaining adequate welding temperature.

§192.629

Purging of pipelines.

[Effective Date: 11/12/70]

(a) When a pipeline is being purged of air by use of gas, the gas must be released into one end of the line in a moderately rapid and continuous flow. If gas cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the gas.

(b) When a pipeline is being purged of gas by use of air, the air must be released into one end of the line in a moderately rapid and continuous flow. If air cannot be supplied in sufficient quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be released into the line before the air.

GUIDE MATERIAL

Note: Although not required, operators of Type B gathering lines should consider the use of written purging procedures.

1 PURGING INSIDE BUILDINGS

- (a) If a service line terminates indoors and purging is necessary, its contents should be vented to an unconfined outside location using tubing, hose, or other means. Service lines and customer piping served by low pressure, where the volume is small and the purging will not constitute a hazard, may be purged indoors as follows.
 - (1) Through an appliance burner equipped with a continuous source of ignition, or
 - (2) Monitoring the discharge point of the purge with a combustible gas indicator and stopping the purge as soon as gas is detected.
- (b) The gas should not be purged into a confined space or area where there is an ignition source. Personnel should ensure there is adequate ventilation and control the purging rate.
- (c) Metallic components of purge lines should be grounded to prevent a static electrical discharge. See guide material under §192.751.

2 NOTIFICATIONS

- (a) Operators may consider including information on purging interior gas piping directly to the outside in public awareness messages or communications with plumbers and construction trades.
- (b) For notification of public officials and the public in the vicinity of purge or discharge, see 4 of the guide material under §192.751.

3 SERVICE LINES WITH EXCESS FLOW VALVES (EFV)

For service lines containing an EFV, see guide material under §192.381 for purging considerations.

4 REFERENCES

- (a) AGA XK1801, "Purging Manual."
- (b) NFPA 54/ANSI Z223.1, "National Fuel Gas Code."

§192.631

Control room management.

[Effective Date: 03/24/17]

(a) **General.**

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

- (i) Distribution with less than 250,000 services, or
- (ii) Transmission without a compressor station, the operator must have and follow written procedures that implement only paragraphs (d) (regarding fatigue), (i) (regarding compliance validation), and (j) (regarding compliance and deviations) of this section.

(2) The procedures required by this section must be integrated, as appropriate, with operating and emergency procedures required by §§192.605 and 192.615. An operator must develop the procedures no later than August 1, 2011, and must implement the procedures according to the following schedule. The procedures required by paragraphs (b), (c)(5), (d)(2) and (d)(3), (f) and (g) of this section must be implemented no later than October 1, 2011. The procedures required by paragraphs (c)(1) through (4), (d)(1), (d)(4), and (e) must be implemented no later than August 1, 2012. The training procedures required by paragraph (h) must be implemented no later than August 1, 2012, except that any training required by another paragraph of this section must be implemented no later than the deadline for that paragraph.

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

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

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

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

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

(5) The roles, responsibilities and qualifications of others with the authority to direct or supersede the specific technical actions of a controller.

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

(1) Implement sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 (incorporated by reference, see §192.7) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of sections 1, 4, 8, 9, 11.1, and 11.3 of API RP 1165 are not practical for the SCADA system used;

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

safety are made to field equipment or SCADA displays;

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

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

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

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

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

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

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

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

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

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

(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;

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

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

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

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

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

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

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

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

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

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

(i) Controller fatigue;

- (ii) **Field equipment;**
- (iii) **The operation of any relief device;**
- (iv) **Procedures;**
- (v) **SCADA system configuration; and**
- (vi) **SCADA system performance.**

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

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

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

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

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

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

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

(6) Control room team training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers (control room personnel) during normal, abnormal or emergency situations. Operators must comply with the team training requirements under this paragraph by no later than January 23, 2018.

(i) **Compliance validation.** Upon request, operators must submit their procedures to PHMSA or, in the case of an intrastate pipeline facility regulated by a State, to the appropriate State agency.

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

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

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

[Issued by Amdt. 192-112, 74 FR 63310, Dec. 3, 2009 with Amdt. 192-112 Correction, 75 FR 5536, Feb. 3, 2010; Amdt. 192-117, 76 FR 35130, June 16, 2011; Amdt. 192-123, 82 FR 7998, Jan. 23, 2017]

GUIDE MATERIAL

1 GENERAL

(a) Section 192.631 applies to any operator of a pipeline (facility) that uses a control room and controllers to monitor and control at least some of those pipeline facilities remotely through a Supervisory Control and Data Acquisition (SCADA) system. An operator is required to have written plans that cover all of the components listed in the sections below.

(b) Certain operators are required to develop the appropriate procedures to comply with only fatigue mitigation (§192.631(d)), compliance validation (§192.631(i)), and compliance and deviation (§192.631(j)).

(c) Operators of Type A gathering lines need to determine the applicability of control room management under §192.631 (§192.9(c)). The requirements of this section do not apply to Type B gathering lines (§192.9(d)).

(d) When determining the number of services under the oversight of a control room, the total should equal the number of services that are served by a single control room as reported to PHMSA-OPS on the annual report (§191.11).

(e) A single control room that oversees the following may be required to meet all of the requirements

of §192.631.

- (1) Several distribution systems having an aggregate total of 250,000 services or more at any one time.
 - (2) Several transmission systems and any one of the systems has a compressor station.
 - (3) A transmission system that has a compressor station and a distribution system of less than 250,000 services.
 - (4) A distribution system of 250,000 services or more and a transmission system that does not have a compressor station.
- (f) Where an operator has several control rooms that oversee distinct distribution systems and each control room oversees a system of less than 250,000 services, the operator is only required to comply with the fatigue mitigation, compliance validation, and compliance and deviation requirements of §192.631(a)(1).
- (g) An operator may already have many of the required components as either written or unwritten procedures. Existing procedures, such as those required by §§192.605 and 192.615, may be modified to meet the additional requirement of control room management, and unwritten procedures should be documented. The operator should verify that there are no conflicts between new control room management procedures and existing procedures.

2 CONTROLLER

- (a) A controller is a person who monitors and controls pipeline operations from a control room (see §192.3). Monitoring the pipeline means the person reviews real-time or near real-time operational information such as pressures and flows via a SCADA system. Controlling the pipeline is the ability to change pressures or flows via a SCADA system or by contacting someone else to make the change in the field.
- (b) Many compressor stations have what is often referred to as a control room. This is a place where station operators monitor the station operation, but may also control the pipeline operations in and out of the station. An operator should review the function of these remote control rooms to determine if personnel are actually serving as controllers. If these remote persons are not authorized to make changes without confirmation from the central control room, they should not be considered controllers.
- (c) An individual who accesses the SCADA system for other incidental business purposes such as monitoring, commercial reasons, customer information, or general information should not be considered a controller.
- (d) A person in a 24-hour manned location (e.g., police station, 911 center) should not be considered a controller under §192.631, especially for small gas systems, where that person:
 - (1) does not use a computer-type interface with a keyboard or mouse and a display screen (or touch-controlled screen);
 - (2) is charged with watching a gauge or light without understanding the implications; or
 - (3) is only provided with specific instructions as to whom to contact when certain changes are noted.

3 COMPONENTS OF CONTROL ROOM MANAGEMENT PROCEDURES

3.1 General.

- (a) Controllers of gas systems have a wide variety of roles due to the differences and complexities of various gas systems. Transmission system control functions may be primarily focused on moving gas from Point A to Point B. Distribution system control functions may be primarily focused on maintaining adequate pressures and flows for end-use consumers. Control room management procedures should be tailored to the specific type of system.
- (b) Procedures can be existing procedures that are modified to meet the prescribed requirements of §192.631.
- (c) The control room management procedures should complement the operator's existing procedural manual for operations, maintenance, and emergencies.

3.2 *Controller roles and responsibilities.*

Section 192.631(b) requires operators to define the roles and responsibilities of the controller during normal, abnormal, and emergency operating conditions. This section also requires operators to define the roles, responsibilities, and qualifications of others authorized to direct or supersede the actions of the controller.

(a) Normal operating conditions.

- (1) Types of normal operating conditions might include the following.
 - (i) Gas flow control and monitoring.
 - (ii) Gas pressure control and monitoring.
 - (iii) Equipment operation and monitoring.
 - (iv) System requirements and monitoring.
 - (v) Start/stop of compressor stations to meet system requirements.
 - (vi) Gas delivery schedule adjustments.
 - (vii) Gas storage monitoring.
 - (viii) Interconnects and delivery nominations.
 - (ix) Pressure set-point adjustments.
 - (x) Activation or deactivation of pipelines for routine operations.
 - (xi) Pigging operations.
 - (xii) Notifications to field personnel.
- (2) Procedures should contain the following.
 - (i) A description of normal operating conditions.
 - (ii) A clear definition of the controller's authority over normal system operations. Consideration should be given to the responsibilities that could be within a controller's range of authority, without requiring any supervisory oversight or approval.
 - (iii) A communication protocol should designate who a controller should notify and what information the controller should provide during normal operational changes. This could be as simple as a log, or could rely on computerized records to note the changes. The communication protocol should define the required communications between the control room and field operations personnel.
 - (iv) Recordkeeping requirements for controller shift changes.

(b) Abnormal operating conditions.

- (1) Types of abnormal operating conditions might include the following.
 - (i) Loss of communication between the SCADA display and a field device.
 - (ii) An operable field device that does not respond to a SCADA command.
 - (iii) An unexpected shutdown of field equipment, such as a compressor engine.
 - (iv) An unexpected closure of a valve.
 - (v) Pressure exceeding MAOP or pressure limits.
 - (vi) Pressure falling below delivery requirements.
 - (vii) False or abnormal readings.
 - (viii) High-high alarms.
 - (ix) Activation of a safety device, such as a relief valve.
 - (x) Emergencies on connecting pipelines.
 - (xi) Any other malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property as defined by the operator.
 - (xii) For transmission operators, events defined by the requirements of §192.605(c).
- (2) Procedures should contain the following.
 - (i) A description of operations that would constitute an abnormal operating condition or situation.
 - (ii) Actions that should be taken by a controller upon becoming aware of an abnormal operating condition.
 - (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

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.
 - (ix) Report of unauthorized system hacking (cyberattack), physical tampering, or other physical acts of sabotage.
 - (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. In the case of incidents related to attempted or confirmed breach of security or cyber security, the Department of Homeland Security recommends operators make notifications to its agencies as advised in guide material (j) and (k) under §191.5.

Notification criteria can be found in the TSA Pipeline Security Guidelines. (March 2018; reference Guide Material Appendix G-192-1, Section 2).

- (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

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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

data.

(g) Recordkeeping.

A crucial part of the SCADA system is the recordkeeping function provided by the system. One component is how often information is received from the field. Acquired data is sent to a computer memory to be retained. Operators should consider data polling frequencies, the location of information on the pipeline system, and computer memory in determining how much information needs to be retained. Too much data may clog the system and allow a controller to miss critical pressure measurements. Too little data may lead to false conclusions. An operator may choose to vary the polling times based on factors such as the importance of the data, critical locations, and the need for up-to-date information to make decisions. The retained data is often used for flow analysis and efficiency studies, but is particularly important for reviewing abnormal operations, emergencies, and incidents.

- (h) Section 192.631(c)(4) requires that backup SCADA systems are tested at least once each calendar year, but at intervals not to exceed 15 months. These tests may be done in conjunction with the annually required manual operation tests, or may be done separately.

4.2 Controller interface.

- (a) Section 192.631(c)(1) requires the implementation of certain sections of API RP 1165 (see §192.7 for IBR), when changing or upgrading SCADA systems. If implementation of API RP 1165 is impractical, an operator should use sound engineering practices or safety analyses to explain why compliance is impractical or is unnecessary. The justification needs to be in writing (§192.631(j)). The justification should be included either in the procedures or in other suitable locations. The level of safety should be equal to or greater than that which would have been provided if the operator had followed API RP 1165.

- (b) SCADA screen displays are the primary point of interaction between the controller and the pipeline system. Consideration should be given to the following when changing SCADA displays.

- (1) Amount of data shown on any screen at one time.
- (2) Summary screens for aggregating important data.
- (3) Navigational tools to minimize the number of controller actions (typically mouse clicks) to move between screens.
- (4) Highlighting the important data.
- (5) Location of data on the display.
- (6) Consistency of layouts, data locations, font types, and use of color and objects across multiple screens (objects are symbols on the screen that are used to represent field devices).
- (7) Differences between data that is shown in a normal operating state and data that is shown in an abnormal or alarm state.
- (8) Consistency of displays within a company.
- (9) Consistency of displays between a main control room and remote locations.

4.3 Alarm management.

- (a) Alarms come in several different varieties. Most alarms notify the controller that an unusual condition exists on the pipeline or associated equipment. Some alarms notify the controller of a condition that may directly affect pipeline safety (e.g., high pressure). Some alarms may notify the controller of an abnormal condition on a piece of field equipment (e.g., low oil pressure on a compressor). Other alarms may notify the controller of a situation that does not affect pipeline safety (e.g., security alarms), but requires controller action. Every alarm that comes in through the SCADA system should require some type of controller action. However, some alarms may be informational and notify the controller that an automated process has initiated. Operators should consider the following.

- (1) Alarm prioritization (possibly providing another means to monitor alarms that are not associated with the safety and integrity of the pipeline).
- (2) Other control room tasks that could distract a controller from the SCADA display.
- (3) Configuring alarms that a controller will see to elicit a response by the controller.
- (4) Alarm response method (e.g., direct intervention by a controller, elevation to a higher

- authority, simply logging the event)
- (b) Each operator using a SCADA system is required to have a written alarm management plan that addresses each requirement of §192.631(e). The alarm management plan should contain the following.
 - (1) Definition of each alarm that will be viewed by a controller and why the point is an alarm.
 - (2) Parameters, such as set-point values, for each defined alarm.
 - (3) Actions to be taken by the controller when an alarm is activated.
 - (4) A method to log the following points affecting pipeline safety.
 - (i) Alarms that have been temporarily inhibited.
 - (ii) Alarms that have been permanently removed.
 - (iii) Alarms that have provided false information.
 - (iv) Alarms that have had forced or manual values.
 - (5) Intervals for the alarm review.
 - (6) A process for reviewing alarms and general activity directed to controllers. A review of points affecting pipeline safety that have been disabled, had alarms inhibited, or had forced or manual values must be performed monthly (§192.631(e)(2)). A review and verification of all alarms and set points should be done annually. If one part of a system has substantially more alarms than another, an operator may consider the redistribution of alarm responsibilities.
 - (7) Recordkeeping requirements for the review processes.
 - (c) Operators that use a single controller on duty should develop a method to allow controllers to be notified of alarms while away from their console or desk.

4.4 Point-to-point verification.

- (a) Section 192.631(c)(2) requires point-to-point verification between safety-related field devices and SCADA displays. This verification must be performed on changes made to SCADA displays, in addition to newly installed or modified field devices. The point-to-point verification generally involves a field technician at the site of the field device communicating with a controller (or other qualified person) and verifying that the value being transmitted by the field device matches the values being displayed on the SCADA screen, and that the data activates the alarm if outside the set parameters. Operators might consider performing point-to-point verifications annually or during regular calibration cycles. The verification plan should include written procedures that describe and record the verification process.
- (b) Examples of safety-related field devices that might require point-to-point verification include the following.
 - (1) Valve status indicators.
 - (2) Pressure transmitters.
 - (3) Flow-rate transmitters.
 - (4) Compressor status indicators.
 - (5) Emergency shutdown status.
 - (6) Leak detection indicators.
 - (7) RTU communication status indicators.

4.5 SCADA system design and monitoring to protect from unauthorized access.

- (a) Operators should consider the following methods for securing authorized access by hardening physical and software borders around SCADA systems to limit the risk to the safe operation of pipelines.
 - (1) Segregating the control system network from the corporate network.
 - (2) Limiting remote connection ports to the control system and if necessary, requiring token-based authentication to gain access.
 - (3) Adding physical protection around remote sites with SCADA network access.
 - (4) Enhancing user access control on SCADA system networks and devices and limiting access to critical systems to individuals with safety or business needs.
 - (5) Employing application whitelisting (the practice of explicitly allowing some identified entities access to a particular privilege, service, mobility, or recognition – the reverse of blacklisting)

and strict policies on peripheral devices (e.g., removable media, printers, scanners) connected to the SCADA network.

- (6) Monitoring unauthorized usage.
- (b) See references in 10 below.

5 OPERATING EXPERIENCE

- (a) An operator should periodically review relevant operating information to enhance the control room management plan. Reportable incidents (for definition, see §191.3) must be reviewed to determine if the following factors contributed to the incident (§192.631(g)(1)).
 - (1) Controller fatigue.
 - (2) Field equipment.
 - (3) Control room procedures.
 - (4) SCADA configuration and performance.
 - (5) Operation of any relief device (for transmission facilities, the operation of a relief device should already be noted as an abnormal operation).
- (b) Post-emergency reviews, as required by §192.615(b)(3), should examine whether controller actions contributed to the emergency. In addition to emergencies and reportable incidents, an operator should review abnormal operations (§192.605(c)), accidents, failure investigations (§192.617), root-cause investigations, or near misses as these might also provide valuable information. Any deficiencies or improvements noted during the review should be documented, and changes to the procedures should be implemented, if appropriate.
- (c) The review procedure should specify the records needed to provide documentation of the incident reviews.

6 MANAGEMENT OF CHANGE (§192.631(f))

- (a) Changes are regular occurrences during the course of pipeline operations requiring effective management through established processes and procedures. Operators should identify and document changes that might impact a controller's ability to monitor or control the pipeline facilities. Communications between the control room, management, and field personnel are a vital part of the control room MOC process. Operators should consider controller involvement when implementing the following changes to pipeline facilities.
 - (1) Temporary interruption or limitation of gas flow (e.g., valve closure, pipeline shutdown).
 - (2) Restoration of gas flow capability (e.g., valve opening, completion of maintenance outage).
 - (3) Temporary limitation or restoration of control (e.g., compressor maintenance outage, regulator or city-gate station maintenance).
 - (4) Temporary or permanent change in pipeline flow patterns (e.g., placing new pipeline facility in service, removing a pipeline from service, flow reversal).
 - (5) Change in established MAOP due to regulatory oversight or integrity management limitation.
 - (6) Purchase or sale of assets.
 - (7) Change to existing equipment (e.g., valves, piping) or new equipment coming online.
 - (8) Newly constructed facility (e.g., pipeline, compressor station, measurement or regulator station) being turned on line.
 - (9) Converting an existing liquid pipeline to natural gas service
 - (10) Procedural change affecting operations, maintenance, or safety.
 - (11) Change to operating agreement.
 - (12) Pigging or other maintenance activity.
 - (13) Change to control systems or SCADA.
 - (14) Emergency or abnormal situation.
 - (15) Implementation of change resulting from the required reviews in 5 above.
- (b) Information about planned changes (e.g., temporary flow patterns, new facilities, blow-down activities) to a controlled pipeline facility should be brought to the attention of the controller through direct planning involvement.

- (c) An MOC plan for a control room may be a separate document, or an existing MOC process may be modified to address the requirements of a control room. An operator is encouraged to consolidate procedures, where possible, to reduce the number of potential conflicts between multiple documents.

7 TRAINING (§192.631(h))

The controller training program may include the following.

- (a) Appropriate training for activities that would be considered covered tasks in the operator qualification (OQ) program.
 - (1) An operator should continue to implement the OQ regulations (Subpart N) through the application of the four-part test for covered tasks. The operator should also determine whether any new tasks will be added to the OQ program when implementing control room management procedures. The operator should define both generic and specific covered tasks for controllers.
 - (2) Certain control room procedures that are developed should be incorporated into the OQ program, as appropriate.
- b) Training content that is specific to controller roles and responsibilities.
 - (1) A working knowledge of the pipeline system, including the following.
 - (i) Practical knowledge of how fluid dynamics, electrical power, and communications could impact operations (for communications, see 3.3 above).
 - (ii) Information about how pressure and flow in all pipeline segments are impacted by control actions.
 - (iii) Information about flexibility and limitations at inlet points, mainline valves, stations, and delivery points.
 - (iv) MAOP and any imposed lower pressures on all pipeline segments within the controller's area of responsibilities.
 - (2) All reasonably foreseeable operational configurations (setups) in its training program, including those setups that are repeated on an infrequent basis (possibly quarterly or greater intervals). Examples of infrequent operations include the following.
 - (i) Seasonal operating parameters.
 - (ii) Start-up and shutdown.
 - (iii) Line reversals.
 - (iv) Combining pipelines (through valve operation) to operate in common rather than separately.
 - (v) Bleed valve operations.
 - (vi) Power-loss failure modes.
 - (vii) Slack line conditions.
 - (viii) Purging.
 - (ix) Running in-line inspection tools.
 - (3) A list of foreseeable operating scenarios that is more likely to cause an AOC, simultaneous AOCs, or multiple AOCs in sequence for training controllers on how to recognize and handle them. Section 192.631(h)(2) requires that the training program for AOCs include either tabletop exercises or computerized simulation methods.
 - (4) A review of historical alarm logs to identify appropriate scenarios for training.
 - (5) Accidents, incidents, near misses, non-reportable events (e.g., small leaks, audit findings), and circumstances that could better inform and better train controllers to safely control the pipeline and recognize and correctly respond to abnormal, unusual, or emergency conditions as defined in 5 above. Events in which controllers contributed to the event are important to avoid recurrence of controller mistakes. Also, proper controller reaction is an important aspect in avoiding recurrence of other types of incidents.
 - (6) Lessons learned from field equipment deficiencies that could affect control room operations.

The following are some examples.

- (i) Instrumentation that is out of calibration, resulting in a false alarm or inaccurate display of operational parameters (e.g., pressure, flow).
 - (ii) Valve limit switches that provide incorrect information on valve status.
 - (iii) Inappropriate setting for relief equipment compared to alarm set points.
 - (iv) Discovery of a mainline valve previously unknown to the controller.
- (7) The responsibilities for communication, including the operator's communications plan and emergency plan requirements.
- (c) Provisions for recordkeeping to demonstrate that each controller has successfully completed the controller operator qualification and training program, including requalification (§192.631(j)(1)). Records should include the following.
- (1) Controller name and training date.
 - (2) Course materials, including descriptions of exercises and simulations employed during the training.
 - (3) Tests and results.
- (d) Training and exercises that include controllers and other individuals, defined by the operator, who would operationally collaborate with control room personnel during normal, abnormal, or emergency situations (§192.631(h)(6)).
- (e) An operator's control room management procedures must include provisions for training program review each calendar year, but at intervals not exceeding 15 months between reviews (§192.631(h)).

8 SHIFT WORK AND FATIGUE (§192.631(d))

Many control rooms are 24-hour operations, staffed by controllers that work in shifts. Shift work or long hours can result in controller fatigue. Control room management procedures should address staffing requirements to maintain the safe operation of the pipeline. Written procedures must establish a maximum controller service-hour limit and should take into consideration the unique factors of the operator's system. Deviation from the limits may occur during emergencies, but should only be permitted as necessary for the safe operation of the pipeline. Deviations from service-hour limits must be documented (§192.631(j)(2)). Operators are required to provide education and training to controllers and appropriate supervisory personnel on fatigue awareness and fatigue mitigation.

8.1 Shift scheduling.

- (a) Shift length and schedule rotations must allow controllers opportunity for eight hours of continuous sleep (§192.631(d)(1)). In addition, operators are also required to establish the maximum hours of service for controllers. Considerations in developing and managing shift schedules should include the following.
- (1) Number of available controllers.
 - (2) Length of each shift.
 - (3) Minimizing the disruption of normal sleep patterns.
 - (4) Overlap time, if any, between shifts.
 - (5) Time off between shifts (e.g., 8-hour shifts have 16 hours of "off" time, 10-hour shifts have 14 hours of "off" time, 12-hour shifts have 12 hours of "off" time).
 - (6) Controller travel time between home and control room.
 - (7) Rotation and time off between shift changes (e.g., day shift to night shift and night shift to day shift).
 - (8) Coverage in the event of unexpected controller absence.
 - (9) Single controller shifts.
 - (10) Overtime scheduling and limitations on "double" shifts.
 - (11) Controllers that also perform other non-control room functions.
- (b) Operators should develop procedures to provide for and document control room coverage during an emergency situation that would result in a controller's maximum hours of service being exceeded. Deviations from normal shifts must be documented (§192.631(j)(2)).

- (c) Operators are required to demonstrate compliance with their established shift lengths and schedule rotations (§192.631(d)(1) and (j)(1)). An operator should also consider the time controllers spend performing non-controller activities and commuting. Methods of accurately recording hours of service might include the following.
 - (1) Time cards.
 - (2) Shift-change records.
 - (3) Keycards.
 - (4) Any other method that can reasonably demonstrate controller hours of service.

8.2 *Fatigue awareness.*

Fatigue awareness training may be included in the OQ plan or in a separate plan. Fatigue awareness and mitigation training should include educating controllers and their supervisors on the following subjects.

- (a) *Fatigue.*
 - (1) Definition.
 - (2) Signs and symptoms.
 - (3) Causes.
 - (4) Effects on the human body.
 - (5) Use of stimulants, such as caffeine.
 - (6) Relation to physical activity and nutrition.
 - (7) Accumulation.
 - (8) Driving.
 - (9) Countermeasures.
 - (10) Relation to off-duty activities.
- (b) *Sleep.*
 - (1) Circadian rhythms (i.e., body clock)
 - (2) Importance of sufficient sleep.
 - (3) Physiological effects of inadequate sleep.
 - (4) Psychological effects of inadequate sleep.
 - (5) Sleep environment.
 - (6) Causes of sleep deprivation.
 - (7) Sleep disorders.
 - (8) Medication effects.

8.3 *Fatigue mitigation.*

- (a) An operator should implement means designed to mitigate on-duty controller fatigue and procedures for addressing when a controller has been identified as fatigued. Operators that use a single controller should develop a method to allow controllers to reduce fatigue and still be aware of changes or alarms that might occur while away from their console or desk.
 - (1) Methods to reduce fatigue in a controller's work environment may include the following.
 - (i) Adjusting control room environmental factors (e.g., lighting, temperature, sound).
 - (ii) Strategic use of break periods.
 - (iii) Varying tasks during shifts.
 - (iv) Making exercise time or equipment available.
 - (2) An adequate recovery period in the form of "off" time should be provided to controllers when changing shift cycles from night-to-day or day-to-night.
 - (3) Fatigue identification procedures should include the following.
 - (i) A method to notify appropriate supervision.
 - (ii) A means or plan to replace or substitute a controller that has been identified as fatigued.
- (b) An operator might consider providing a sleep area or transporting a fatigued controller home to prevent that controller from driving.

9 COMPLIANCE AND DEVIATION

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

10 REFERENCES

- (a) API RP 1165, "Recommended Practice for Pipeline SCADA Displays" (see §192.7 for IBR).
- (b) API RP 1168, "Pipeline Control Room Management."
- (c) OPS Advisory Bulletin ADB-2016-06. "Pipeline Safety: Safeguarding and Securing Pipelines From Unauthorized Access" (81 FR 89183, Dec. 9, 2016; reference Guide Material Appendix 6-192-1, Section 2).
- (d) Department of Homeland Security guidance document "Recommended Practice: Improving Industrial Control System Cybersecurity with Defense-in-Depth Strategies." September 2016. Found online at: http://ics-cert.us-cert.gov/sites/default/files/recommended_practices/NCCIC_ICSCERT_Defense_in_Depth_2016_S508C.pdf.
- (e) TSA Pipeline Security Guidelines. March 2018.

§192.632

Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines.

[Effective Date: 06/01/2020]

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

(a) *ECA Analysis.*

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

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

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

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

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

(iv) If SMYS or actual material yield and ultimate tensile strength is not known or not documented by traceable, verifiable, and complete records, then the operator must assume 30,000 p.s.i. or determine the material properties using § 192.607.

(3) The ECA must analyze the interaction of defects to conservatively determine the most limiting predicted failure pressure. Examples include, but are not limited to, cracks in or near locations with corrosion metal loss, dents with gouges or other metal loss, or cracks in or near dents or other deformation damage. The ECA must document all evaluations and any assumptions used in the ECA process.

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

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

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

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

(3) Operators may use “other technology” if it is validated by a subject matter expert to produce an equivalent understanding of the condition of the pipe equal to or greater than pressure testing or an inline inspection program. If an operator elects to use “other technology” in the ECA, it must notify PHMSA in advance of using the other technology in accordance with § 192.18. The “other technology” notification must have:

- (i) Descriptions of the technology or technologies to be used for all tests, examinations, and assessments, including characterization of defect size used in the crack assessments (length, depth, and volumetric); and
- (ii) Procedures and processes to conduct tests, examinations, assessments and evaluations, analyze defects, and remediate defects discovered.

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

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

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

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

(4) An operator must use unity plots or equivalent methodologies to validate the performance of the ILI tools in identifying and sizing actionable manufacturing and construction related anomalies. Enough data points must be used to validate tool performance at the same or better statistical confidence level provided in the tool specifications. The operator must have a process for identifying defects outside the tool performance specifications and following up with the ILI vendor to conduct additional in-field examinations, reanalyze ILI data, or both.

(5) Interpretation and evaluation of assessment results must meet the requirements of §§ 192.710, 192.713, and subpart O, and must conservatively account for the accuracy and reliability of ILI, in-the-ditch examination methods and tools, and any other assessment and examination results used to determine the actual sizes of cracks, metal loss, deformation and other defect dimensions by applying the most conservative limit of the tool tolerance specification. ILI and in-the-ditch examination tools and procedures for crack assessments (length and depth) must have performance and evaluation standards confirmed for accuracy through confirmation tests for the defect types and pipe material vintage being evaluated. Inaccuracies must be accounted for in the procedures for evaluations and fracture mechanics models for predicted failure pressure determinations.
(6) Anomalies detected by ILI assessments must be remediated in accordance with applicable criteria in §§ 192.713 and 192.933.

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

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

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

GUIDE MATERIAL

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

§192.634

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) 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

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

§192.636

Transmission lines: Response to a rupture; capabilities of rupture-mitigation valves (RMVs) or alternative equivalent technologies.

[Effective Date: 10/05/2022]

(a) **Scope.** The requirements in this section apply to rupture-mitigation valves (RMVs), as defined in §192.3, or alternative equivalent technologies, installed pursuant to §§192.179(e), (f), (g), and 192.634.

(b) **Rupture identification and valve shut-off time.** An operator must, as soon as practicable but within 30 minutes of rupture identification (see § 192.615(a)(12)), fully close any RMVs or alternative equivalent technologies necessary to minimize the volume of gas released from a pipeline and mitigate the consequences of a rupture.

(c) **Open Valves.** An operator may leave an RMV or alternative equivalent technology open for more than 30 minutes, as required by paragraph (b) of this section, if the operator has previously established in its operating procedures and demonstrated within a notice submitted under § 192.18 for PHMSA review, that closing the RMV or alternative equivalent technology would be detrimental to public safety. The request must have been coordinated with appropriate local emergency responders, and the operator and emergency responders must determine that it is safe to leave the valve open. Operators must have written procedures for determining whether to leave an RMV or alternative equivalent technology open, including plans to communicate with local emergency responders and minimize environmental impacts, which must be submitted as part of its notification to PHMSA.

(d) **Valve monitoring and operation capabilities.** An RMV, as defined in § 192.3, or alternative equivalent technology, must be capable of being monitored or controlled either remotely or by on-site personnel as follows:

(1) Operated during normal, abnormal, and emergency operating conditions;
(2) Monitored for valve status (i.e., open, closed, or partial closed/open), upstream pressure, and downstream pressure. For automatic shut-off valves (ASV), an operator does not need to monitor remotely a valve's status if the operator has the capability to monitor pressures or gas flow rate within each pipeline segment located between RMVs or alternative equivalent technologies to identify and locate a rupture. Pipeline segments that use manual valves or other alternative equivalent technologies must have the capability to monitor pressures or gas flow rates on the pipeline to identify and locate a rupture; and

(3) Have a back-up power source to maintain SCADA systems or other remote communications for remote-control valve (RCV) or automatic shut-off valve (ASV) operational status, or be monitored and controlled by on-site personnel.

(e) **Monitoring of valve shut-off response status.** The position and operational status of an RMV must be appropriately monitored through electronic communication with remote instrumentation or other equivalent means. An operator does not need to monitor remotely an ASV's status if the operator has the capability to monitor pressures or gas flow rate on the pipeline to identify and locate a rupture.

(f) **Flow modeling for automatic shut-off valves.** Prior to using an ASV as an RMV, an operator must conduct flow modeling for the shut-off segment and any laterals that feed the shut-off segment, so that the valve will close within 30 minutes or less following rupture identification, consistent with the operator's procedures, and in accordance with §192.3 and this section. The flow modeling must include the anticipated maximum, normal, or any other flow volumes, pressures, or other operating conditions that may be encountered during the year, not exceeding

a period of 15 months, and it must be modeled for the flow between the RMVs or alternative equivalent technologies, and any looped pipelines or gas receipt tie-ins. If operating conditions change that could affect the ASV set pressures and the 30-minute valve closure time after notification of potential rupture, as defined at §192.3, an operator must conduct a new flow model and reset the ASV set pressures prior to the next review for ASV set pressures in accordance with §192.745. The flow model must include a time/pressure chart for the segment containing the ASV if a rupture occurs. An operator must conduct this flow modeling prior to making flow condition changes in a manner that could render the 30-minute valve closure time unachievable.

(g) **Manual Valves in non-HCA, Class 1 locations.** For pipeline segments in a Class 1 location that do not meet the definition of a high consequence area (HCA), an operator submitting a notification pursuant to §§192.18 and 192.179 for use of manual valves as an alternative equivalent technology may also request an exemption from the requirements of §192.636(b).

GUIDE MATERIAL

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

SUBPART M MAINTENANCE

§192.701

Scope.

[Effective Date: 11/12/70]

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

GUIDE MATERIAL

Type B gathering lines are exempt from this subpart, except for §§192.703(c), 192.706, and 192.707.

For Type B gathering lines that are replaced, relocated, or otherwise changed, the design, installation, construction, initial inspection, and initial testing must be in accordance with the requirements for transmission lines (§192.9(d)).

§192.703

General.

[Effective Date: 11/12/70]

- (a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.
- (b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.
- (c) Hazardous leaks must be repaired promptly.

GUIDE MATERIAL

1 GENERAL

Any time a pipeline is found to be damaged or deteriorated to the extent that its serviceability is impaired or leakage constituting a hazard is evident, immediate temporary measures should be employed to protect the public and property. If it is not feasible to make a permanent repair at the time of discovery, permanent repairs should be made as soon as feasible.

2 REPAIR OF PIPE

2.1 General.

Prior to repairing a pipeline, the operator should consider the operating conditions, design, and maintenance history, as necessary, to ensure that repair actions do not further damage the pipe. Where warranted, the operating pressure should be lowered, pipe exposure should be limited, access to the area should be limited, personnel protection should be provided, and fire extinguishing equipment should be available.

2.2 Repairs to distribution lines.

Methods of permanent repair to non-thermoplastic distribution lines include the following.

- (a) Cutting out as a cylinder and replacing the piece of damaged pipe.
- (b) Applying a full-encirclement welded split sleeve of appropriate design.
- (c) Applying a properly designed bolt-on type of leak clamp or sleeve.
- (d) For steel pipe, applying a fillet-welded steel plate patch of similar material of equal or greater thickness, of appropriate grade, and with rounded corners.

2.3 *Repairs to transmission lines and Type A gathering lines.*

For repairs to steel transmission lines and Type A gathering lines, see §§192.711, 192.713, 192.715, 192.717, and 192.751. Section 192.485 allows the alternative of lowering the MAOP on corroded transmission pipe where a safe operating pressure can be calculated based on the remaining strength of the corroded pipe. See guide material under §192.485.

2.4 *Permanent repairs to thermoplastic piping.*

Repair methods for thermoplastic piping include the following.

- (a) Cutting out as a cylinder and replacing the piece of damaged pipe.
- (b) Applying a properly designed bolt-on type saddle, leak clamp, or sleeve.
- (c) Installing a repair sleeve meeting the requirements of ASTM D2513 (see listing in §192.7, not IBR for §192.703).
- (d) See guide material under §192.311.
- (e) For gas flow control during repair (e.g., squeeze-off and re-opening), see 5 of the guide material under §192.321.

2.5 *Repair procedures.*

The repair should be made in accordance with a qualified repair procedure.

2.6 *Compression couplings in pipelines.*

Repairs using compression couplings and repairs to pipelines that may contain compression couplings should consider the following.

- (a) Coupled pipe is subject to pullout near bends, near the end of the pipeline, at temporary end closures, while performing stoppering or stopping procedures, when the pipeline is severed, and while long sections of pipeline are exposed.
- (b) Some factors that can contribute to pullout potential are the pipe diameter, material, and surface; operating pressure; temperature changes; buoyancy; and soil moisture, compaction, and type.
- (c) The procedure for safely repairing the pipeline should include consideration of the following precautionary, preventive, and mitigating actions.
 - (1) Reviewing maps and records to determine if couplings exist.
 - (2) Reviewing and following manufacturer's recommendation for installing and maintaining compression couplings.
 - (3) Analyzing each project for the potential of coupling pullout, including pullouts on adjacent line sections.
 - (4) Performing an electrical continuity test to check for indications of unknown insulating couplings.
 - (5) Reviewing contingency procedures to be used in the event of a pullout.
 - (6) Reducing pressure prior to excavation.
 - (7) Installing anchors sufficient to resist anticipated pullout forces caused by movement of the pipeline in any direction.
 - (8) Reinforcing known couplings.
 - (9) Minimizing the length of exposed pipe during the repair work.
 - (10) Backfilling offset replacement piping before severing the pipeline.
 - (11) Providing a separate excavation for pressure control operations to prevent injury from pullout of an unknown coupling.
 - (12) Designing and installing protective sleeves or bridging when making mechanical joints that either connect plastic piping or plastic piping to steel piping. This is especially true for PE pipe manufactured prior to 1982, since some is known to be susceptible to premature brittle-like

failures. Also, attention should be given to any recommendations by the pipe manufacturer. For protective sleeves, see guide material under §192.367.

2.7 *Inspection and testing.*

- (a) All repairs to distribution lines should be visually inspected and leak tested at operating pressure.
- (b) All repairs to transmission lines should be tested in accordance with §192.719.
- (c) For safety during pressurization, the operator should consider restricting access to pipeline facilities such as the following.
 - (1) Test header.
 - (2) Exposed piping and appurtenances.
 - (3) Repair fittings.
 - (4) Compression couplings.
 - (5) Dead ends.
 - (6) Areas near the pipeline facility that might be affected.

3 **CONSIDERATIONS FOR REPLACEMENT OR RENEWAL**

3.1 *All pipelines.*

A guide to assist an operator in developing a method of evaluating the serviceability and need for replacement or renewal of existing pipelines is AGA XL0702, "Distribution Pipe: Repair and Replacement Decision Manual."

3.2 *Cast iron pipe.*

See Guide Material Appendix G-192-18.

3.3 *Other considerations.*

A gas facility might be considered for replacement if located near an exposed, deteriorated electrical conduit.

4 **REALIGNMENT OF PIPING**

4.1 *Steel.*

(a) *General.*

Prior to realigning (moving in any direction) piping, the operator should establish a procedure for determining the feasibility of safely realigning the piping and performing the work. A reference for developing such a procedure is PRCI L51717, "Pipeline In-Service Relocation Engineering Manual."

- (1) *Feasibility analysis.* The procedure for determining the feasibility of safely realigning the pipe should include consideration of the following.
 - (i) Determining the amount of realignment required.
 - (ii) Reviewing the operating history of the involved section, such as records of leaks, damage, and external and internal corrosion.
 - (iii) Reviewing 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.
 - (iv) Performing a new stress analysis, reviewing relevant prior stress analyses and safe practices established by prior projects.
 - (v) Determining the maximum safe operating pressure during the realignment.
 - (vi) When the feasibility analysis indicates a potentially unsafe condition may be caused by moving the pipe under normal operating conditions, consideration should be given to isolating the line segment, lowering the pressure in the segment, depressuring the segment, or other appropriate action.
- (2) *Performance of the work.* The procedure for performing the work should include consideration of the following.
 - (i) Training and qualification of personnel for the realignment procedure.

- (ii) Monitoring the pressure during the realignment to ensure that the maximum safe operating pressure is not exceeded.
 - (iii) Providing for shutdown and purging of the piping if necessary.
 - (iv) Minimizing employee and public exposure at the work site.
 - (v) Potential adverse effects of weather conditions, ground and surface water, and bank stability.
 - (vi) External inspection of the exposed pipe for variation from the feasibility study and for visible defects, such as dents, gouges, grooves, arc burns, corrosion, and coating damage.
 - (vii) Making appropriate repairs.
 - (viii) Full control by the operator of the actual realignment process.
 - (ix) The adequacy of pipe supports to prevent unintended movement.
 - (x) Ditch padding and backfill materials to prevent damage to the pipe and coating.
 - (xi) Backfill and compaction procedures to prevent additional movement due to settlement after realignment.
- (b) Additional considerations for compression-coupled piping.
- (1) *Feasibility analysis*. The procedure for determining the feasibility of safely realigning the piping should also include consideration of the following.
 - (i) Reviewing the manufacturers' recommendations for installing and maintaining compression couplings.
 - (ii) Analyzing each project for the potential of coupling pullout, including pullouts on line sections connected to each side of the project piping.
 - (iii) Installing anchors to resist unbalanced forces on each side of the project piping.
 - (iv) Reinforcing all involved couplings prior to actually realigning the pipe.
 - (2) *Performance of the work*. The procedure for performing the work should also include consideration of the following.
 - (i) Reducing pressure prior to excavating, reinforcing, and realigning.
 - (ii) Minimizing excavation during the locating and reinforcing activities.
- (c) References.
- (1) PRCI L51717, "Pipeline In-Service Relocation Engineering Manual," (PR218-9308).
 - (2) API RP 1117, "Movement of In-Service Pipelines."

4.2 Cast iron.

Realignment of cast iron pipe is not recommended. See Guide Material Appendix G-192-18.

4.3 Plastic.

Realignment of plastic pipe is not recommended except where replacement is not feasible. If realignment is necessary, then the following should be considered.

- (a) General.
 - See 4.1 (a) and (b) above.
- (b) Additional considerations.
 - (1) Damaged sections should be replaced.
 - (2) Recommendations of pipe and fitting manufacturers should be reviewed in determining the allowable pipe movement and joint deflection.
 - (3) To minimize or avoid stress concentration at joints during and after realignment, the operator should:
 - (i) Consider the effect of thermal stresses.
 - (ii) Provide continuous pipe support (e.g., bridging, protective sleeves, ditch grading, and proper backfill) to prevent movement from settlement after realignment. For protective sleeves, see guide material under §192.367.
 - (iii) Review records to determine the type of plastic material used in manufacturing the pipe. Thermosetting plastics (e.g., fiberglass reinforced epoxy composite pipe) and some thermoplastics (e.g., ABS and PVC) allow only marginal flexing of joints without damage.
 - (iv) During PE piping relocation, minimum bend radius recommendations should be observed to avoid overstressing joints at fittings in PE piping, which can lead to

premature failures. For bend radius recommendations, see guide material under §192.367.

- (v) Review records to determine the types of fittings that may be involved. Some fittings provide little, if any, pullout resistance.
- (4) Branch lines and service lines connected to the section to be realigned should be reviewed and replaced or extended as necessary. Extensions will usually be required to prevent imposed tensile stresses in the pipe material due to the realignment.
- (5) Buried valves should be properly supported and aligned for correct operational orientation.

5 GAS LEAKAGE CONTROL GUIDELINES

Guide Material Appendix G-192-11 (Natural Gas Systems) and Guide Material Appendix G-192-11A (Petroleum Gas Systems) provide guidelines for the detection, classification, and control of gas leakage. These appendices include information related to the prompt repair of hazardous leaks.

Type B operators must repair hazardous leaks as required by §192.9(d)(8) and may follow the guidelines of Table 3a Leak Classification and Action Criteria for Grade 1 leaks or other operator criteria to define hazardous leaks. Repairs to Type B gathering lines should be made in accordance with requirements for transmission lines.

§192.705
Transmission lines: Patrolling.
[Effective Date: 07/08/96]

(a) Each operator shall have a patrol program to observe surface conditions on and adjacent to the transmission line right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation.

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

Class location of line	Maximum interval between patrols	
	At highway and railroad crossings	At all other places
1, 2	7½ months; but at least twice each calendar year.	15 months; but at least once each calendar year.
3	4½ months; but at least four times each calendar year.	7½ months; but at least twice each calendar year.
4	4½ months; but at least four times each calendar year.	4½ months; but at least four times each calendar year.

(c) Methods of patrolling include walking, driving, flying or other appropriate means of traversing the right-of-way.

[Amdt. 192-21, 40 FR 20279, May 9, 1975; Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]

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.
 - (i) Suspicious persons, activities, or devices in the vicinity of pipe facilities. See guide material under §191.5 regarding reporting of such occurrences to federal authorities. As appropriate, an operator should report such instances to local law enforcement.

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 or videos) used by the person making the patrol should identify areas near the transmission line that might require special

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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 or suspicious activities 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.

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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

- (1) See Guide Material Appendix G-192-17 for the explicit requirements of each patrol, survey, inspection, or test required by Subparts L and M.
- (2) 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.
- (3) See guide material under §192.227 for records demonstrating the qualification of each individual welder at the time of construction of steel transmission and regulated gathering lines.
- (4) See §192.285(e) for records demonstrating the qualification of each individual plastic pipe joiner at the time of construction of plastic transmission line.

§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,

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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 lesser 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 Amendments 192-125 and 192-130.

§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

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.

$$P = \frac{2S(t - \frac{3}{32})(0.72)}{D}$$

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 listing in §192.7, not IBR for §192.713).

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

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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 updated in accordance

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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

transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS.

- (2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp.
- (3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 p.s.i. (276 MPa) gage SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.
- (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design.
- (5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

[Amdt. 192-11, 37 FR 21816, Oct. 14, 1972; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-88, 64 FR 69660, Dec. 14, 1999]

GUIDE MATERIAL

- (a) For information regarding replacement and repairs, see guide material under §192.713.
- (b) For information regarding reliable engineering tests and analyses, see guide material under §192.485.
- (c) For information regarding scheduling integrity management repairs, see 2 of the guide material under §192.933.

§192.719

Transmission lines: Testing of repairs.

[Effective Date: 12/18/86]

(a) *Testing of replacement pipe.* If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe must be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

(b) *Testing of repairs made by welding.* Each repair made by welding in accordance with §§192.713, 192.715, and 192.717 must be examined in accordance with §192.241.

[Amdt. 192-54, 51 FR 41634, Nov. 18, 1986]

GUIDE MATERIAL

When tie-in girth welds are not strength tested, they should be nondestructively tested in accordance with §192.241.

§192.720

Distribution systems: Leak repair.

[Effective Date: 01/22/19]

Mechanical leak repair clamps installed after January 22, 2019 may not be used as a permanent repair method for plastic pipe.

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

GUIDE MATERIAL

No guide material available at present.

§192.721

Distribution systems: Patrolling.

[Effective Date: 07/08/96]

(a) The frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage, and the consequent hazards to public safety.

(b) Mains in place or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled —

(1) In business districts, at intervals not exceeding 4½ months, but at least four times each calendar year; and

(2) Outside business districts, at intervals not exceeding 7½ months, but at least twice each calendar year.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-78, 61 FR 28770, June 6, 1996 with Amdt. 192-78 Correction, 61 FR 30824, June 18, 1996]

GUIDE MATERIAL

1 GENERAL

Distribution mains 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 such as the following.

(a) Excavation, grading, demolition or other construction activity which 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 distribution facilities or a freshly backfilled excavation over or near distribution facilities.

(c) Physical deterioration of exposed piping, pipeline spans, and structural pipeline supports, such as bridges, piling, headwalls, casings, and foundations.

(d) Land subsidence, earth slippage, soil erosion, extensive tree root growth, flooding, climatic conditions, and other natural causes that can result in impressed secondary loads.

(e) Need for additional distribution pipeline identification and marking in private right-of-way and in rural areas.

(f) Damage to casing vents and carrier pipe leakage at cased crossings.

(g) Suspicious persons or activities in the vicinity of pipe facilities. See guide material under §191.5 regarding reporting of such occurrences. As appropriate, an operator should report such instances to local law enforcement.

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 SPECIAL LOCATIONS

Places or structures where physical movement or external loading may cause leakage or failure should be identified by the operator based on knowledge of the system characteristics and problem areas. Where a main or its support structure is constructed and maintained to resist movement and external loading, the operator may determine that special-location patrols are not required.

Areas where an operator should consider performing increased patrol activity include the following.

- (a) Bridge crossings.
- (b) Aerial crossings.
- (c) Unstable river banks.
- (d) Exposed water crossings.
- (e) Areas susceptible to washout.
- (f) Landslide areas.
- (g) Areas susceptible to earth subsidence, such as mines and landfills.
- (h) Tunnels.
- (i) Railroad crossings.
- (j) Attachments to buildings or other structures.
- (k) Facilities or support structures that require maintenance, until repaired.

4 REPORTS

Patrol reports should indicate hazardous conditions or suspicious activities observed, corrective action taken or recommended, and the nature and location of any deficiencies.

§192.723

Distribution systems: Leakage surveys.

[Effective Date: 07/14/04]

(a) Each operator of a distribution system shall conduct periodic leakage surveys in accordance with this section.

(b) The type and scope of the leakage control program must be determined by the nature of the operations and the local conditions, but it must meet the following minimum requirements:

(1) A leakage survey with leak detector equipment must be conducted in business districts, including tests of the atmosphere in gas, electric, telephone, sewer, and water system manholes, at cracks in pavement and sidewalks, and at other locations providing an opportunity for finding gas leaks, at intervals not exceeding 15 months, but at least once each calendar year.

(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months. However, for cathodically unprotected distribution lines subject to §192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least

once every 3 calendar years at intervals not exceeding 39 months.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-70, 58 FR 54524, Oct. 22, 1993; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-94, 69 FR 32886, June 14, 2004 with Amdt. 192-94 Correction, 69 FR 54591, Sept. 9, 2004]

GUIDE MATERIAL

1 FREQUENCY

1.1 *Business districts.*

In determining business districts, the following should be considered.

- (a) Areas where the public regularly congregates or where the majority of the buildings on either side of the street are regularly utilized for industrial, commercial, financial, educational, religious, health, or recreational purposes.
- (b) Areas where gas and other underground facilities are congested under continuous street and sidewalk paving that extends to the building walls on one or both sides of the street.
- (c) Any other area that, in the judgment of the operator, should be so designated.

1.2 *Minimum requirements.*

The minimum frequency for leakage surveys is established by §192.723(b).

1.3 *Increased frequency.*

Consideration should be given to increased frequency for leak surveys based on the particular circumstances and conditions. Surveys should be conducted most frequently in those areas with the greatest potential for leakage and where leakage could be expected to create a hazard. Factors to be considered in establishing the frequency of leak surveys include the following.

- (a) Piping system. Age of pipe, materials, type of facilities, operating pressure, leak history records, and other studies.
- (b) Corrosion. Known areas of significant corrosion, or areas where corrosive environments are known to exist. Cased crossings of roads, highways, railroads, etc., due to susceptibility to unique corrosive conditions.
- (c) Piping location. Proximity to buildings or other structures and the type and use of the buildings. Proximity to areas of concentrations of people.
- (d) Environmental conditions and construction activity. Conditions that could increase the potential for leakage or cause leaking gas to migrate to an area where it could create a hazard such as the following.
 - (1) Weather conditions.
 - (2) Areas of known frost heaving.
 - (3) Wall to wall pavement.
 - (4) Porous soil conditions.
 - (5) Areas of high construction activity.
 - (6) Trenchless excavation activities (e.g., boring).
 - (7) Blasting. See Guide Material Appendix G-192-16.
 - (8) Large earth moving equipment.
 - (9) Heavy traffic.
 - (10) Unstable soil or areas subject to earth movement.
- (e) Other. Any other condition known to the operator that has significant potential to initiate a leak or to permit leaking gas to migrate to an area where it could result in a hazard, such as the following.
 - (1) Earthquake.
 - (2) Subsidence.
 - (3) Flooding.
 - (4) An increase in operating pressure.
 - (5) The extensive growth of tree roots around pipeline facilities that can exert substantial

longitudinal force on the pipe and nearby joints.

1.4 Special one-time surveys.

- (a) Special one-time surveys should be considered following exposure of the pipeline to unusual stresses (e.g., earthquakes, blasting) or trenchless installation of foreign buried facilities that cross gas pipelines.
- (b) Special one-time surveys should be considered where gas migration and the ability to quickly identify the location of the suspected leak is affected by weather-related conditions (e.g., water-saturated ground, frozen ground). See Guide Material Appendices G-192-11, Section 5.5 and G-192-11A, Section 5.5.

1.5 Establishment and review of survey frequency.

Leak survey frequencies should be based on operating experience, sound judgment, and a knowledge of the system. Once established, frequencies should be reviewed periodically to affirm that they are still appropriate. Leak surveys may be accomplished in conjunction with patrolling, scheduled inspections, and other routine activities.

2 GAS LEAKAGE CONTROL GUIDELINES

See Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.

§192.725

Test requirements for reinstating service lines.

[Effective Date: 11/12/70]

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

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

GUIDE MATERIAL

No guide material necessary.

§192.727

Abandonment or deactivation of facilities.

[Effective Date: 02/17/09]

(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is

no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.

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

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

(g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

(1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at <http://www.npms.phmsa.dot.gov> or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001; fax (202) 366-4566; e-mail InformationResourcesManager@phmsa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(2) [Reserved].

[Amdt. 192-8, 37 FR 20694, Oct. 3, 1972; Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-71, 59 FR 6579, Feb. 11, 1994; Amdt. 192-89, 65 FR 54440, Sept. 8, 2000 with Amdt. 192-89 Correction, 65 FR 57861, Sept. 26, 2000; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; RIN 2137-AE29, 73 FR 16562, Mar. 28, 2008; RIN 2137-AE29 (#2), 74 FR 2889, Jan. 16, 2009]

GUIDE MATERIAL

Note: Although not required, operators of Type B gathering lines should consider the following when abandoning facilities.

1 GENERAL

(a) The following procedural guidance covers the maintenance of pipelines (including service lines) not

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actively being used to transport gas and the permanent abandonment of transmission lines, Type A gathering lines, distribution mains, and distribution service lines. See 5 below for information regarding inactive pipelines.

- (b) For planned shutdown in connection with abandonment or deactivation, see Guide Material Appendix G-192-12.
- (c) Abandonment should not be considered complete until the gas or liquid hydrocarbons contained within the abandoned section poses no potential hazard. An operator should consider diameter, length, location, or other parameters when identifying piping to be abandoned that needs to be purged.
- (d) Pipelines may be purged using air, inert gas, or water. If air is used as the purging agent, precautions should be taken to ensure that no liquid hydrocarbons are present. See §192.629 and AGA XK1801, "Purging Manual" for purging of natural gas and liquid hydrocarbons.

2 ABANDONMENT OF TRANSMISSION PIPELINES AND DISTRIBUTION MAINS

2.1 *Check prior to abandonment.*

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

2.2 *Sealing.*

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

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

2.3 *Additional considerations in addition to purging and sealing.*

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

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

2.4 *Segmenting the abandoned sections.*

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

2.5 *Removal of above-grade facilities and filling voids.*

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

3 ABANDONMENT OF DISTRIBUTION SERVICE LINES IN CONJUNCTION WITH MAIN ABANDONMENT

3.1 *Curb valves and curb boxes.*

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

3.2 *Meter risers and headers.*

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

3.3 Service lines below grade through a basement wall.

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

3.4 Outside meter set assembly and above-grade entrances.

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

4 ABANDONMENT OF SERVICE LINES FROM ACTIVE MAINS

4.1 Disconnecting.

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

4.2 Sealing.

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

4.3 Other actions.

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

5 INACTIVE PIPELINES

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

5.1 General.

Each operator should consider the following elements when determining whether to abandon or continue maintaining an inactive pipeline.

- (a) Location (e.g., business district, urban, suburban, rural).
- (b) Type of piping material.
- (c) Joining method (e.g., welding, fusion, compression couplings).
- (d) Cathodic protection.
- (e) Operating pressure.
- (f) Likelihood of reactivation.
- (g) Leakage and maintenance history.
- (h) Proposed construction.

5.2 Continuing maintenance.

Provisions for continuing maintenance of inactive pipelines should be included in the procedural manual for operations, maintenance, and emergencies required under §192.605. (See guide material under §192.3 for definition of "inactive pipeline.") Examples of such maintenance include the following.

- (a) Regularly scheduled leak surveys and patrolling.
- (b) Corrosion control monitoring of cathodically protected systems.
- (c) Maps and records for damage prevention.
- (d) Evaluating aboveground piping for the following.

- (i) Atmospheric corrosion.
- (ii) Susceptibility to damage from vehicles and other forces.
- (iii) Unauthorized activities.

6 INACTIVE SERVICE LINES

In addition to 5.2 above, the operator should consider the following for continuing maintenance of inactive service lines.

- (a) Identifying and documenting the location of inactive service lines in a record management system.
- (b) Developing criteria for abandonment.

§192.729
(Removed.)

[Effective Date: 02/11/95]

§192.731

Compressor stations: Inspection and testing of relief devices.

[Effective Date: 11/22/82]

(a) Except for rupture discs, each pressure relieving device in a compressor station must be inspected and tested in accordance with §§192.739 and 192.743, and must be operated periodically to determine that it opens at the correct set pressure.

(b) Any defective or inadequate equipment found must be promptly repaired or replaced.

(c) Each remote control shutdown device must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year, to determine that it functions properly.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982]

GUIDE MATERIAL

The MAOP of regulated segments of gathering lines could be protected by equipment that is located in non-regulated compressor stations. While the compressor station might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or isolation of downstream regulated segments could be regulated.

Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine inspections of overpressure protection devices.

§192.733
(Removed.)

[Effective Date: 02/11/95]

§192.735

Compressor stations: Storage of combustible materials.

[Effective Date: 08/06/15]

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

(b) Aboveground oil or gasoline storage tanks must be protected in accordance with NFPA-30 (incorporated by reference, see §192.7).

[Amdt. 192-119, 80 FR 168, Jan. 5, 2015 with Amdt. 192-119 Correction, 80 FR 46847, Aug. 6, 2015]

GUIDE MATERIAL

No guide material necessary.

§192.736

Compressor stations: Gas detection.

[Effective Date: 07/13/98]

(a) Not later than September 16, 1996, each compressor building in a compressor station must have a fixed gas detection and alarm system, unless the building is—

- (1) Constructed so that at least 50 percent of its upright side area is permanently open; or
- (2) Located in an unattended field compressor station of 1,000 horsepower (746 kW) or less.

(b) Except when shutdown of the system is necessary for maintenance under paragraph (c) of this section, each gas detection and alarm system required by this section must—

- (1) Continuously monitor the compressor building for a concentration of gas in air of not more than 25 percent of the lower explosive limit; and
- (2) If that concentration of gas is detected, warn persons about to enter the building and persons inside the building of the danger.

(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.

[Issued by Amdt. 192-69, 58 FR 48460, Sept. 16, 1993; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 GENERAL

See §192.171 for design of gas detection and alarm systems.

2 MAINTENANCE AND TESTING OF GAS DETECTION AND ALARM SYSTEMS

The operator should develop the following.

- (a) Maintenance and testing procedures to ensure proper function of the gas detectors and alarm system.
- (b) Procedures for calibrating the gas detection equipment and verifying that the alarms are functioning properly.

§192.737
(Removed.)

[Effective Date: 02/11/95]

§192.739

Pressure limiting and regulating stations: Inspection and testing.

[Effective Date: 10/08/04]

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is—

- (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) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressures consistent with the pressure limits of §192.201(a); and
- (4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

(b) For steel pipelines whose MAOP is determined under §192.619(c), if the MAOP is 60 psi (414 kPa) gage or more, the control or relief pressure limit is as follows:

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

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-96, 69 FR 27861, May 17, 2004 with Amdt. 192-96 DFR Confirmation, 69 FR 54248, Sept. 8, 2004]

GUIDE MATERIAL

1 GENERAL

1.1 Gathering lines.

- (a) The MAOP of gathering lines could be protected by equipment that is located outside of the regulated segment of pipeline. While the pressure limiting station, relief device, or regulating station might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or

isolation of downstream regulated segments could be regulated by function.

- (b) Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine inspections of overpressure protection devices.

1.2 General considerations.

- (a) Prior to operating equipment, a review of the station's operating mode(s) should be performed using resources such as station schematics or SME input. The operator should follow system operation procedures including applicable recommendations for Control Room Management plans (see guide material under §192.631). The review should include the operating system pressure and what might occur during overpressurization event.
- (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.

Addendum 1, June 2022

Addendum 4, May 2024

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.

7 OVERPRESSURE PROTECTION CONSIDERATIONS FOR LOW-PRESSURE DISTRIBUTION SYSTEMS

During an activity that could potentially cause overpressurization, use the type of gauges suitable (pressure range) for the system being worked on. Continuously observe and monitor the operating pressures in appropriate locations. Leave gauges in place for an appropriate length of time after the work is completed to identify any lagging pressure changes.

§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.

4 ABNORMAL OPERATING CONDITIONS (§192.741(c))

If an abnormal operating condition is indicated, the operator should:

- (a) Investigate and determine if pressure regulating and auxiliary control equipment is in satisfactory operating condition. Any unsatisfactory condition found by inspection or test should be immediately corrected.
- (b) Investigate and determine if the pressure recording device is in proper operating condition. Any unsatisfactory condition found by inspection or test should be corrected as soon as practical.
- (c) Investigate the distribution system in the vicinity of a high-pressure or low-pressure condition.

§192.743

Pressure limiting and regulating stations: Capacity of relief devices.

[Effective Date: 10/08/04]

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

(b) If review and calculations are used to determine if a device has sufficient capacity, the calculated capacity must be compared with the rated or experimentally determined relieving capacity of the device for the conditions under which it operates. After the initial calculations, subsequent calculations need not be made if the annual review documents that parameters have not changed to cause the rated or experimentally determined relieving capacity to be insufficient.

(c) If a relief device is of insufficient capacity, a new or additional device must be installed to provide the capacity required by paragraph (a) of this section.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-55, 51 FR 41633, Nov. 18, 1986; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-96, 69 FR 27861, May 17, 2004 with Amdt. 192-96 DFR Confirmation, 69 FR 54248, Sept. 8, 2004]

GUIDE MATERIAL

1 CAPACITY DETERMINATION BY IN-PLACE TESTING

1.1 *Determination of actual flow.*

The capacity of the relief valve system can be determined by direct measurement under full flow conditions or by determining a coefficient through limited flow tests that can be used in calculating the full capacity. References for performing the appropriate tests include the following.

- (a) UG-131 of the ASME Boiler and Pressure Vessel Code, Section VIII (see listing in §192.7, not IBR for §192.743).
- (b) API RP 525, "Testing Procedure for Pressure-Relieving Devices Discharging Against Variable Back Pressure" (Revised 1960; Discontinued).

1.2 *Demonstrating adequate capacity.*

- (a) A test may be conducted by simulating conditions of maximum pressure and supply volume conditions for the pressure control source of the protected segment and minimum flow conditions on the discharge side of the source. Under these conditions the pressure control source should be wide open. Adequate capacity is determined if the relief device prevents the downstream pressure from exceeding that permitted by §192.201.
- (b) When conducting such a test, care must be taken to maintain service and to prevent overpressuring any components in the system.

2 CAPACITY DETERMINATION BY CALCULATION

2.1 *Determination of required relief capacity.*

- (a) The maximum possible flow through the source supplying the system being protected should be determined.
 - (1) When the source is controlled by the operator, recognized engineering formulas may be used to make the calculations based on data published by, or otherwise obtained from, the manufacturer of the equipment used as a pressure source or pressure control component.
 - (i) A lesser capacity than calculated above is acceptable if calculations of flow in the piping on the inlet or outlet of the equipment show a lesser throughput to be the maximum.
 - (ii) Data used in these calculations should be selected so that the capacity calculated will represent the maximum throughput in actual operations, including emergencies. Minimum demand may be considered.
 - (2) When the operator does not have control of the source, information should be obtained to adequately determine the maximum flow and pressure capacity of that source. This information may then be used as the basis for relief capacity requirements.
- (b) When more than one pressure regulating or compressor station feeds a pipeline, relief capacity based on complete failure of the largest capacity regulator or compressor should be adequate. The operator should consider subsequent failures that may be caused by an initial failure.

2.2 *Determination of relief device capacity.*

See 2 of the guide material under §192.201.

3 REDETERMINATION

A redetermination of the required relief capacity should be made whenever there are changes in the system that could increase the supply of gas from the source, the capacity of the control device, or the ability of the relief device to handle the required flow.

4 GATHERING LINES

- (a) The MAOP of gathering lines could be protected by equipment that is located outside of the regulated segment of pipeline. While the relief device might not be subject to Part 192 due to its location, individual devices that provide overpressure protection or isolation of downstream regulated segments could be regulated by function.
- (b) Although not required for non-regulated devices, operators of Type B gathering lines should consider performing routine capacity calculations for relief devices.

§192.745

Valve maintenance: Transmission lines.

[Effective Date: 10/15/03]

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

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

(c) For each remote-control valve (RCV) installed in accordance with §§ 192.179 or 192.634, an operator must conduct a point-to-point verification between SCADA system displays and the installed valves, sensors, and communications equipment, in accordance with § 192.631(c) and (e).

(d) For each alternative equivalent technology installed on an onshore pipeline under §§192.179(e), 192.179(f), or 192.634 that is manually or locally operated (i.e., not a rupture-mitigation valve (RMV), as that term is defined in § 192.3):

(1) Operators must achieve a valve closure time of 30 minutes or less, pursuant to §192.636(b), through an initial drill and through periodic validation as required in paragraph (d)(2) of this section. An operator must review and document the results of each phase of the drill response to validate the total response time, including confirming the rupture, and valve shut-off time as being less than or equal to 30 minutes after rupture identification.

(2) Within each pipeline system and within each operating or maintenance field work unit, operators must randomly select a valve serving as an alternative equivalent technology in lieu of an RMV for an annual 30-minute-total response time validation drill that simulates worst-case conditions for that location to ensure compliance with § 192.636. Operators are not required to close the valve fully during the drill; a minimum 25 percent valve closure is sufficient to demonstrate compliance with drill requirements unless the operator has operational information that requires an additional closure percentage for maintaining reliability. The response drill must occur at least once each calendar year, with intervals not to exceed 15 months. Operators must include in their written procedures the method they use to randomly select which alternative equivalent technology is tested in accordance with this paragraph.

(3) If the 30-minute-maximum response time cannot be achieved during the drill, the operator must revise response efforts to achieve compliance with § 192.636 as soon as practicable but no later than 12 months after the drill. Alternative valve shut-off measures must be in place in accordance with paragraph (e) of this section within 7 days of a failed drill.

(4) Based on the results of response-time drills, the operator must include lessons learned in:

- (i) Training and qualifications programs;
- (ii) Design, construction, testing, maintenance, operating, and emergency procedures manuals; and
- (iii) Any other areas identified by the operator as needing improvement.

(5) The requirements of this paragraph (d) do not apply to manual valves who, pursuant to §192.636(g), have been exempted from the requirements of §192.636(b).

(e) Each operator must develop and implement remedial measures to correct any valve installed

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on an onshore pipeline under §§192.179(e), 192.179(f), or 192.634 that is indicated to be inoperable or unable to maintain effective shut-off as follows:

(1) Repair or replace the valve as soon as practicable but no later than 12 months after finding that the valve is inoperable or unable to maintain effective shut-off. An operator must request an extension from PHMSA in accordance with §192.18 if repair or replacement of a valve within 12 months would be economically, technically, or operationally infeasible; and

(2) Designate an alternative valve acting as an RMV within 7 calendar days of the finding while repairs are being made and document an interim response plan to maintain safety. Such valves are not required to comply with the valve spacing requirements of this part.

(f) An operator using an ASV as an RMV, in accordance with §§192.3, 192.179, 192.634, and 192.636, must document and confirm the ASV shut-in pressures, in accordance with 192.636(f), on a calendar year basis not to exceed 15 months. ASV shut-in set pressures must be proven and reset individually at each ASV, as required, on a calendar year basis not to exceed 15 months.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003; Amdt. 192-130, 87 FR 20940, Apr. 8, 2022]

GUIDE MATERIAL

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

1 INSPECTION AND MAINTENANCE

- (a) Each operator should review the valve manufacturer's recommendations and develop an appropriate maintenance program.
- (b) Valves should be operated to the extent necessary to establish operability during an emergency. When operating the valve, precautions should be taken to avoid a service outage or overpressuring the system.
- (c) When maintenance is completed, the operator should verify that the valves are in the proper position.
- (d) When inspecting or maintaining valves, the location reference data contained in the operator's records should be compared with field conditions. Changes, such as referenced landmarks, street alignment, and topography, should be noted and incorporated in the records.
- (e) Gathering line emergency valves.
 - (i) While a valve protecting a Type A gathering line might not be subject to Part 192 due to its location, it could be regulated by function.
 - (ii) Although not required, operators should consider performing routine inspections on valves protecting Type B gathering lines.

2 PRECAUTIONS

If a valve is to be partially operated, precautions should be taken to avoid a service outage or overpressuring the system. Such precautions might include the following.

- (a) Documenting the valve type (e.g., plug, gate, ball) and the direction and number of turns to operate the valve.
- (b) Verifying the orientation of the valve in relation to the valve stops.
- (c) Monitoring downstream pressure for any variation from normal operating pressure.
- (d) Qualified personnel (see Subpart N) and system operating SME, if necessary, should be involved in the inspection or adjustment of any valve that could affect pressure regulating equipment or other pressure sensing equipment.
- (e) See guide material under §192.739 for equipment associated with pressure regulation and overpressure protection.

3 INOPERABLE VALVES

The following actions should be considered if a valve is found inoperable.

- (a) Repair the valve to make it operable.
- (b) Designate another valve or valves to substitute for the inoperable valve that will provide a similar level of effectiveness for isolating the line section. Consideration should be given to the following.

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- (1) Spacing requirements as prescribed in §192.179.
 - (2) Updating records for emergency shutdown and future maintenance requirements.
 - (3) Informing employees of the change to the isolation or emergency shutdown plan.
- (c) Replace the valve.

§192.747

Valve maintenance: Distribution systems.

[Effective Date: 10/15/03]

(a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.

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

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-93, 68 FR 53895, Sept. 15, 2003]

GUIDE MATERIAL

1 INSPECTION AND MAINTENANCE

Valves should be checked for adequate lubrication and proper alignment to permit the use of a key, wrench, handle, or other operating device. Where applicable, the valve box or vault should be cleared of any debris that would interfere with or delay the operation of the valve.

2 PRECAUTIONS

If a valve is to be partially operated, precautions should be taken to avoid a service outage or overpressuring the system. Such precautions might include the following.

- (a) Documenting the valve type (e.g., plug, gate, ball) and the direction and number of turns to operate the valve.
- (b) Verifying the orientation of the valve in relation to the valve stops.
- (c) Monitoring downstream pressure for any variation from normal operating pressure.
- (d) Qualified personnel (see Subpart N) and system operating SME, if necessary, should be involved in the inspection or adjustment of any valve that could affect pressure regulating equipment or other pressure sensing equipment.
- (e) See guide material under §192.739 for equipment associated with pressure regulation and overpressure protection.

3 INOPERABLE VALVES

The following actions should be considered if a valve is found inoperable.

- (a) Repair the valve to make it operable.
- (b) Designate another valve or valves to substitute for the inoperable valve that will provide a similar level of effectiveness for isolating the desired area. Consideration should be given to the following.
 - (1) Updating records for emergency shutdown and future maintenance requirements.
 - (2) Informing employees of the change to the isolation or emergency shutdown plan.
- (c) Replace the valve.

4 IDENTIFICATION AND RECORD VERIFICATION

- (a) See §192.181 for additional information on identifying valves necessary for the safe operation of a distribution system.
- (b) See guide material under §192.745 regarding verification of records with current field data.

§192.749
Vault maintenance.

[Effective Date: 07/13/98]

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

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

(c) The ventilating equipment must also be inspected to determine that it is functioning properly.

(d) Each vault cover must be inspected to assure that it does not present a hazard to public safety.

[Amdt. 192-43, 47 FR 46850, Oct. 21, 1982; Amdt. 192-85, 63 FR 37500, July 13, 1998]

GUIDE MATERIAL

1 APPLICABILITY

The following guide material applies to vaults that contain pressure regulating or pressure limiting equipment and have a volumetric internal content of 200 cubic feet or greater. Section 192.749 does not apply to valve access vaults, other underground vault-type structures that have a volumetric internal content of less than 200 cubic feet, or underground vault-type structures that do not contain pressure regulating or limiting equipment (e.g., emergency isolation valve, hand-hole access type). See guide material §192.3 for a definition of vault.

2 HAZARDOUS ATMOSPHERES

Hazardous atmospheres might exist in such vaults due to leakage from components within the vault, or from seepage of gases (e.g., natural gas, nitrogen) or other vapors, fumes, or mists (e.g., gasoline) from outside the vault.

3 DEVELOPMENT OF SAFETY PROCEDURES

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

3.1 Procedures prior to entry.

- (a) Engine exhausts should be kept away from the vault opening.
- (b) All possible sources of ignition should be kept away from the work area, except as may be required in the performance of the work. See §192.751.
- (c) Sufficient safety equipment (e.g., dry chemical fire extinguishers, breathing apparatus, safety harnesses) should be available in the work area.
- (d) Flashlights, lighting fixtures, and extension cords should be of a type approved for hazardous atmospheres.
- (e) Before the cover is removed, the vault atmosphere should be tested for combustible gas. Use the holes or pry holes, or lift the edge of the cover slightly to admit the testing probe. In double cover manholes, it will be necessary to remove the outer cover and partially lift the inner cover to make the test.
- (f) Immediately after removal of the cover, tests for combustible gas and for oxygen deficiency should be made at various levels that can be reached from the surface.
- (g) Results of the tests made in accordance with 3.1(e) and (f) above should determine the procedures

to be followed.

- (1) *Combustibles at 60% of the Lower Explosive Limit or Less (e.g., 3.0% natural gas in air or less).* The vault may be entered without breathing apparatus after establishing, by test, that a safe oxygen level exists, or if continuous forced draft ventilation is maintained. Forced draft ventilation is superior to suction draft ventilation.
- (2) *Combustibles in excess of 60% of the Lower Explosive Limit.* The vault should not be entered unless ventilation maintains combustible level below 60% of the Lower Explosive Limit and a safe oxygen level exists. However, in the event the vault cannot be adequately ventilated and the facility cannot be taken out of service to effect necessary repairs, the vault may be entered with the use of an approved breathing apparatus and safety harness.

3.2 Procedures for vault entry and while working in the vault.

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

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.

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 eliminating static electricity from both the inside and outside of PE pipe.
- (c) A plastic pipe vent or blowdown stack should not be used due to the possibility that venting gas with a high scale or dust content could generate an internal static electrical charge that could ignite the escaping gas. Metal vent stacks should be grounded before placement in the escaping gas stream. Venting should be done downwind at a safe distance from personnel and flammable material.
- (d) To reduce potential sources of ignition, all tools, including squeeze-off tools, used in gaseous atmospheres should be grounded or the non-sparking type.

1.4 *Other sources of ignition.*

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

1.5 *Fire extinguishers.*

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

1.6 *Verification of the presence of gas.*

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

1.7 *Accidental ignition of discharged gas.*

Operators should consider using the following measures to help avoid accidental ignition when gas is discharged in areas subject to public motor vehicle or pedestrian traffic.

- (a) Posting warning signs.
- (b) Directing motor vehicles and pedestrians away from the area by considering the following.
 - (1) Law enforcement.
 - (2) Traffic flaggers.

- (3) Signs (e.g., detour, road closed).
- (4) Barricades.

2 WELDING, CUTTING, AND OTHER HOT WORK

2.1 *General.*

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

2.2 *Pipelines filled with gas.*

When a pipeline or main is to be kept full of gas during welding or cutting operations, the following are recommended.

- (a) A slight flow of gas should be kept moving toward the cutting or welding operation.
- (b) The gas pressure at the site of the work should be controlled by suitable means.
- (c) All slots or open ends should be closed with tape, tightly fitted canvas, or other suitable material immediately after a cut is made.
- (d) Two openings should not be uncovered at the same time.

2.3 *Pipelines containing air.*

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

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

3.1 *General.*

Planned work on gas facilities should incorporate procedures to shut off or minimize the escape of gas. No portion of a pipeline, large-diameter service line, or main should be cut out under pressure, unless the flow of gas is shut off or minimized by the use of line valves, line plugging equipment, bags, stoppers, or pipe squeezers. Where 100% shutoff is not feasible, the following precautions are recommended.

- (a) Plan the job to minimize the escape of gas and sequence steps to limit the time and amount of gas to which personnel are exposed.
- (b) Ensure that the size and position of the cut allows the gas to vent properly even with an employee in the excavation.
- (c) Protect personnel working in a gaseous atmosphere under an overhang, in a tunnel, or in a manhole.

3.2 *Isolating pipeline segments.*

- (a) Preliminary action. The operator should conduct a prework meeting(s) to review the following with the personnel involved.
 - (1) The method of isolation.
 - (2) The purpose of each activity.

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

4 NOTIFICATIONS PRIOR TO PURGE OR BLOWDOWN

4.1 *Public officials.*

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

4.2 *Public in vicinity of gas discharge.*

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

5 REFERENCE

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]

SUBPART N QUALIFICATION OF PIPELINE PERSONNEL

Cautionary Note: Guide material in Subpart N is written specifically for the Regulations as adopted in Amendments 192-86, 192-90, and 192-100. Operators are advised that provisions in the Pipeline Safety Act of 2002 and Office of Pipeline Safety protocols for inspection need to be considered in their compliance with operator qualification.

§192.801

Scope.

[Effective Date: 10/26/99]

- (a) This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.
- (b) For the purpose of this subpart, a covered task is an activity, identified by the operator, that:
 - (1) Is performed on a pipeline facility;
 - (2) Is an operations or maintenance task;
 - (3) Is performed as a requirement of this part; and
 - (4) Affects the operation or integrity of the pipeline.

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999]

GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

1 GENERAL

Guide material under this subpart provides direction for compliance with Subpart N, which covers operator qualification (OQ) of individuals who perform covered tasks on a pipeline facility.

Operators of petroleum gas distribution systems or small natural gas systems (e.g., master meter operators) should review the "Small LP Gas Operator Guide" or the "Small Natural Gas Operator Guide" available at <https://www.phmsa.dot.gov/training/pipeline/guidance-manuals>.

2 CONTRACTORS

- (a) In implementing its OQ program, an operator should consider that any contractor individual who performs covered tasks on the operator's behalf needs to be qualified unless the individual will be directed and observed by an individual that is qualified.
- (b) An operator should consider including provisions in its own written program to address the use of contractor or mutual aid employees performing covered tasks.
- (c) It may be necessary for an operator to work with the contractor or mutual aid employee to ensure that qualifications are established and maintained consistent with the operator's program.

3 EMERGENCY RESPONSE

An operator should plan to use individuals who are qualified under its OQ program for emergency response for tasks that meet the four-part test in §192.801(b).

§192.803
Definitions.

[Effective Date: 08/20/01]

Abnormal operating condition means a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

- (a) Indicate a condition exceeding design limits; or
- (b) Result in a hazard(s) to persons, property, or the environment.

Evaluation means a process, established and documented by the operator, to determine an individual's ability to perform a covered task by any of the following:

- (a) Written examination;
- (b) Oral examination;
- (c) Work performance history review;
- (d) Observation during:
 - (1) Performance on the job,
 - (2) On the job training, or
 - (3) Simulations;
- (e) Other forms of assessment.

Qualified means that an individual has been evaluated and can:

- (a) Perform assigned covered tasks; and
- (b) Recognize and react to abnormal operating conditions.

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999; Amdt. 192-90, 66 FR 43523, Aug. 20, 2001]

GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

1 ABNORMAL OPERATING CONDITION

Operators should identify conditions that would be reasonably recognizable by an individual performing a covered task.

1.1 Incorporation of conditions in task competency requirements.

Conditions that are included in the basic competency requirements for a particular task need not be considered abnormal operating conditions for that task. This is illustrated by the following examples.

- (a) If an operator identifies leak surveys as a covered task, the discovery of a leak need not be considered an abnormal operating condition for the individual performing this task. Finding leaks is an objective of the given task and the individual performing the task is expected to understand how to identify and respond to leaks.
- (b) If monitoring cathodic protection systems using electrical surveys is a covered task, finding a low pipe-to-soil reading need not be considered an abnormal operating condition. To find such readings is an objective of the task, and the individual performing the task is expected to understand how to identify and respond to such conditions.

1.2 Examples of abnormal operating conditions.

Examples of abnormal operating conditions may include the following.

- (a) Escaping gas.
- (b) Fire or explosion.
- (c) Excessive or inadequate pressure.
- (d) Inadequate odorization.

- (e) Damage to facilities.
- (f) Component failure.
- (g) Stray current.
- (h) Unintended movement or unusual loading on the pipeline.
- (i) Adverse or unusual weather conditions.

Qualification for a particular covered task may involve recognizing and reacting to one or more abnormal operating conditions. Some abnormal operating conditions may be common to more than one covered task.

2 COVERED TASKS

See 2.1 of the guide material under §192.805.

3 EVALUATION

Although any of the methods identified in the regulation are acceptable, the operator should consider whether a particular method is suitable for evaluating an individual for a given covered task. For example, if an individual has difficulty in taking written tests, another form of evaluation may be appropriate. If an operator identifies welding as a covered task, evaluation without a performance element would not be appropriate, since §§192.227 and 192.229 require that a welder or welding operator actually make an acceptable weld in accordance with a qualified welding procedure (as required to initially qualify or maintain qualification). The evaluation method selected should enable the operator to determine whether the individual is capable of performing the routine aspects of the covered task as well as recognizing and reacting to abnormal operating conditions associated with the covered task.

3.1 Evaluator.

- (a) A person with responsibility for evaluating an individual's qualifications to perform covered tasks should have the required knowledge, through training or experience, to determine that an individual has the ability to:
 - (1) Perform covered tasks, and
 - (2) Recognize and react to abnormal operating conditions that might arise or be observed while performing those tasks.
- (b) The level of knowledge and experience may vary depending on the method of evaluation. If the evaluation method requires the evaluator to use judgment to determine if the evaluation was passed (e.g., evaluation through observation on the job), then the evaluator should have sufficient knowledge and experience to discern whether the task was performed properly. If the evaluator is merely proctoring a written or computer-based exam, then the evaluator need not be knowledgeable about the subject matter. An operator may use third-party evaluators for qualifying individuals who perform covered tasks, provided that the evaluator meets the above criteria.

3.2 Evaluation method.

- (a) The evaluation method chosen for any specific covered task should include one or more of the following actions.

Note: After October 28, 2002 and December 16, 2004, §192.809(d) and (e), respectively, do not permit work performance history review or observation of on-the-job performance to be the sole evaluation method.

 - (1) Written examination.
 - (2) Oral examination.
 - (3) Work performance history review.
 - (4) Observation during:
 - (i) Performance on the job.
 - (ii) On-the-job or classroom training.
 - (iii) Simulation.
 - (5) Other forms of assessment identified by the operator.

- (b) For any particular evaluation method selected, the operator should assess whether one or more of the other evaluation methods should be used to augment the qualifying evaluation for a given covered task. The evaluations should verify that the individual possesses the knowledge, skills, and abilities to perform the task and recognize and react to abnormal operating conditions. For example, an operator may choose written examination as the primary evaluation method, but also include a task performance observation where the written examination does not provide enough information to perform a complete evaluation.
- (1) Written or oral examinations.

A test used as an evaluation method should be as objective as possible. Questions used in these evaluation methods should be stated in such a way as to not lead the individual to a correct answer.
 - (2) Work performance history review.

In using work performance history review for transitional or initial qualification prior to October 28, 2002, the operator should consider whether the documentation related to performance history is adequate for performing an appropriate evaluation and or demonstrating compliance. Considerations should be as follows.

 - (i) When used as the sole evaluation method for transitional qualification, work performance documentation may not contain sufficient detail to fulfill the part of the qualification requirement related to recognition and reaction to abnormal operating conditions. In some cases, the operator may be able to use documentation of an individual's involvement in:
 - (A) Leak, facility damage, or abnormal operation discoveries,
 - (B) Emergency response or training, and
 - (C) Abnormal operation training.
 - (ii) Generally, affidavits of past performance should not be used as the sole documentation in this evaluation method.
 - (iii) If it is anticipated by the operator that work performance history review will be used as part of future initial or subsequent evaluations, the operator should consider what types of records would be useful for the evaluation. The operator should consider collecting such information as soon as practical in advance of the subsequent evaluation date. Such records may include the following.
 - (A) Documented inspection, testing, and maintenance records.
 - (B) Written performance evaluations regarding covered and related tasks.
 - (C) Any documentation that may have been generated as a result of direct observation of individuals.
 - (iv) Work performance history review may include the following.
 - (A) A search of existing records for documentation of an individual's past satisfactory performance of a covered task.
 - (B) Verification that the individual's work performance history contains no indications of substandard work or involvement in an incident caused by an error in performing a covered task.
 - (C) Verification that the individual has successfully performed the covered task on a regular basis prior to October 26, 1999.
 - (3) Observation on the job, during training, or in a simulation.
 - (i) Observation of an individual, performing a task either on the job or in a simulated setting, is used primarily to verify that the individual possesses the skills and abilities to perform the routine aspects of a task. During observation, verbal interaction may be useful to assess the individual's knowledge.
 - (ii) Abnormal operating conditions can be evaluated through observation in simulated settings, but will not necessarily occur during observation on the job. When observation on the job is used as an evaluation method for a task, the ability to recognize and react to abnormal operating conditions could be evaluated separately or through one or more oral questions asked of the individual by the evaluator during on-the-job observation.
 - (iii) Checklists of key steps in the task, copies of the procedures, or other references can

be helpful in ensuring that the evaluation is performed consistently.

(4) Performance monitoring.

The operator may also consider planned or impromptu observation of performance of covered and related tasks by individuals and developing documentation that could be useful in a work performance history review.

3.3 Evaluation categories.

The three types of qualifications are as follows.

- (a) Transitional qualification means qualification in a covered task completed by October 28, 2002, of an individual who had been performing that task on a regular basis prior to October 26, 1999.
- (b) Initial qualification means the first qualification of an individual in a covered task that is not transitional qualification.
- (c) Subsequent qualification means evaluation of an individual's qualification to perform a covered task, after "transitional" or "initial" qualification, at the interval established by the operator. The subsequent qualification process may use different evaluation criteria than used for transitional or initial qualification. The interval for the first subsequent qualification does not need to start until October 28, 2002. Therefore, if an operator chooses October 28, 2002, as the start date for the subsequent qualification interval applicable to previously qualified individuals, the first subsequent qualification interval for those individuals may exceed the intervals established under the operator's written program. However, for qualifications on or after October 28, 2002, the established subsequent evaluation intervals would apply.

Subsequent evaluations may be used as follows.

- (1) Verify that all necessary changes since the last qualification have been communicated to affected personnel.
- (2) Identify qualification concerns.
- (3) Evaluate the employee's performance over the preceding interval.

4 CONTRACTORS

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

<p>§192.805 Qualification program.</p>
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Each operator shall have and follow a written qualification program. The program shall include provisions to:

- (a) Identify covered tasks;
- (b) Ensure through evaluation that individuals performing covered tasks are qualified;
- (c) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;
- (d) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an incident as defined in Part 191;
- (e) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;
- (f) Communicate changes that affect covered tasks to individuals performing those covered tasks;
- (g) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed; and

(h) After December 16, 2004, provide training, as appropriate, to ensure that individuals performing covered tasks have the necessary knowledge and skills to perform the tasks in a manner that ensures the safe operation of pipeline facilities; and

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

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

GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

1 GENERAL

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

2 ELEMENTS OF THE WRITTEN PROGRAM

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

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

(a) Four-part test.

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

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

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

(i) *An operating task* is one that causes a system or a part of a system to function. Opening and closing a valve is an example of an operating task.

- (ii) A *maintenance task* is one that is performed on an existing system, or part of an existing system, with the intent of preserving its viability. Repairing pipe by grinding or applying a sleeve is an example of a maintenance task, because it is done to an existing portion of the pipeline facility to preserve the portion's viability. Other examples of a maintenance task are any of those associated with replacing or rerouting an existing pipeline, since they too are done to preserve the original pipeline's viability. Tasks performed on a section of pipe that extends an existing section of pipe, however, are not maintenance tasks because the added pipe is not an existing part of the pipeline facility at the time the tasks are performed. Disconnecting pipe to be replaced or rerouted and the connecting of new or replacement pipe to an existing pipeline system may be considered a maintenance task because it involves modification to an existing part of the pipeline facility.
- (3) *Performed as a requirement of Part 192* means that Part 192 specifies that the task must be performed. An operator may choose not to consider tasks that are addressed in its procedural manual that are not specifically required in the Regulations when identifying covered tasks. An operator may also choose not to consider implied tasks (e.g., those that are addressed solely as a result of a requirement for written procedures) and subtasks to those required by Part 192 when identifying covered tasks for its Operator Qualification Program.
- (4) *Affects the operations or integrity of the pipeline* suggests that the improper performance of the task may adversely affect the safe operation or safety of the pipeline.
 - (i) In evaluating the effect on the operation, the one aspect the operator should consider is whether an incorrect performance of a task would cause the design limits of the pipeline to be exceeded. For example, an incorrectly set overpressure protection device could allow the pressure in the pipeline to exceed the limits permitted in the Regulations.
 - (ii) In assessing whether a task could affect the integrity of a pipeline, the operator should consider whether improper performance could make the pipeline unsuitable for operation at its MAOP. The effect need not be instantaneous to meet this criterion. For example, the effect of an incorrectly performed pipe-to-soil reading may not manifest itself until well after the reading is completed. Corrosion may occur unchecked to the extent where the integrity is eventually affected.
- (b) Additional considerations.

The operator's written program should identify the method that the operator uses in determining whether a task is covered or not. Consideration should also be given to identifying how tasks are added or removed from the program.

 - (1) Physical contact is not necessary. The performance of the task does not require that the pipeline be contacted to be considered a "covered task" (i.e., the individual performing the task need not touch the pipeline in order for the task to be considered covered).
 - (i) An operator may identify certain tasks performed by gas control personnel as "covered tasks" if incorrect performance of these tasks could result in unsafe operation of pipeline, and these tasks meet the other three criteria.
 - (ii) Similarly, leak surveys may be another example where the pipeline is not physically contacted with instrumentation or tools.
 - (iii) According to OPS Advisory Bulletin ADB-06-01, the operator may need to consider pipeline excavation activity as a covered task. See OPS ADB-06-01 (71 FR 2613, Jan. 17, 2006; reference Guide Material Appendix G-192-1, Section 2).
 - (2) Location of task performance. Some covered tasks may be considered as being dependent on location for performance of the task. For example, if regulator maintenance is considered a covered task by the operator and it is performed in-place in the field, this would be a covered task. If the regulator is removed from service and taken to an off-site location to be rebuilt, none of the tasks performed at the off-site location would be covered. However, the removal and reinstallation of the regulator would be a covered task.

- (3) Tasks may be identified from any subpart. The review of Part 192 for "covered tasks" should encompass all subparts. For example, welding and corrosion control are not found in the operations and maintenance subparts of Part 192, but both of these activities may be covered tasks if the four-part test outlined in §192.801 is met.
- (4) Covered tasks performed by contractors. Since some contractors may perform covered tasks for more than one operator, contractors may identify covered tasks in a manner different from the operator. The operator should ensure that the covered tasks performed by the contractor encompass the elements of the operator's covered tasks that are being contracted.

2.2 *Evaluation of qualifications (§192.805(b)).*

See 3 of the guide the material under §192.803.

2.3 *Non-qualified individuals (§192.805(c)).*

(a) Covered task performance.

Non-qualified individuals may perform covered tasks under certain circumstances including the non-qualified individual's participation in on-the-job training or when working as part of a crew. A non-qualified individual may only perform a covered task under the following conditions.

- (1) A qualified individual is assigned to direct and observe the non-qualified individual during the performance of the covered task.
- (2) A qualified individual is able to take immediate corrective actions if necessary.

For a person to direct and observe a non-qualified individual, the person should, at all times during the performance of the covered task, be able to correct an improper performance of the task by any individuals being observed.

(b) Directed and observed performance - span of control.

When an operator decides to have a qualified individual direct and observe non-qualified individuals performing covered tasks, the operator should limit the number of individuals being observed by each qualified person. This is based on the ability of the observer to effectively respond to errors that may occur during the performance of the task by the non-qualified individuals. The number may vary based on factors such as the following.

- (1) Complexity of the task.
- (2) Consequence of improper performance of the task.
- (3) Ability of the person performing the observation.
- (4) Knowledge and abilities of the individuals being observed.

(c) When covered task performance may not be appropriate.

Not all covered tasks may lend themselves to performance by individuals that are not qualified, even if observed by a qualified individual.

- (1) High risk of hazard. If the potential errors that may occur in the performance of the task could lead to a hazard because there would not be enough time for the observer to respond, then the operator should not consider permitting non-qualified individuals to perform that covered task. For example, any covered task that may involve cutting or welding on an in-service pipeline may not be appropriate for a non-qualified person to perform under direction and observation of a qualified individual. A mistake that could lead to a hazard would likely not be avoidable, even with the intervention of an observer who is qualified in the task.
- (2) Other regulatory constraints. If the Regulations require specific qualification for a task (e.g., welding, joining of plastic pipe, or performing a hot tap), then an operator that has identified any of these as a covered task should not allow the task to be performed by a non-qualified individual.

2.4 *Performance contributing to an incident (§192.805(d)).*

- (a) Determine if reevaluation of covered task qualification is needed.
If there is reason to believe that an individual's performance of a covered task contributed to an incident, a review of that individual's qualification to perform that covered task should be conducted. The review should determine whether an individual needs to be reevaluated for the covered task. Some errors in performance may not be a result of insufficient qualification but may be attributable to human factors, such as emotional distress or distraction. In these cases, the operator may decide that reevaluation is not needed.
- (b) Determining if other actions are needed.
If the operator concludes that reevaluation is needed, the operator should also determine if there is a deficiency in the evaluation standards used for the most recent qualification. If so, the operator may need to reevaluate the qualification of other individuals who have been qualified in the covered task involved in the incident and make appropriate adjustments to their evaluation process. The operator should also consider whether additional training may be appropriate prior to the reevaluation.
- (c) If task performance by specific individual is not documented.
Since it is not required that performance of each covered task be documented, there may be situations where the operator cannot identify the individual that may have performed the covered task that contributed to an incident. In these cases, the operator should consider reviewing the qualifications of all individuals that may have performed the task, which could have contributed to the incident. This may involve a review of work scheduling documentation, time reports, operator records of individuals performing the particular task in the area over a period of time, and similar records.

2.5 *Reasonable cause to verify qualification (§192.805(e)).*

If there is reason to believe that an individual is no longer qualified to perform a covered task, a review of the individual's qualification should be conducted.

- (a) Indicators.
Concerns regarding an individual's ability to perform a covered task may be prompted by a number of circumstances, which include the following.
 - (1) Change in an individual's physical abilities related to performance of the covered task.
 - (2) Documented statement from the individual or other persons relative to the individual's performance of the covered task.
 - (3) Prolonged absence from performing the covered task.
 - (4) Documented unsatisfactory performance of the covered task.
 - (5) Results of any monitoring that the operator may conduct on covered task performance.
- (b) Course of action.
A method to determine whether an individual needs to be reevaluated may be described in the written OQ program. Upon determination of reasonable cause, the operator should determine the individual's ability to perform the covered task.
 - (1) *Reevaluation.* If, as a result of the review, the operator concludes that the individual is no longer qualified, that individual may be reevaluated in accordance with the OQ program if the individual is still expected to perform the task.
 - (2) *Training and reevaluation.* The operator should consider whether training would be appropriate prior to reevaluation.
 - (3) *Stop using individual for the covered task.* If the individual is no longer able to perform the covered task, the operator should stop using this individual to perform the covered task.

2.6 *Communication of changes (§192.805(f)).*

In addition to communicating changes that affect covered tasks to the individuals who perform those covered tasks (including contractors), the operator should also consider communicating such changes to other individuals that may be affected by the change (e.g., evaluators, supervisors, program administrators). The change may be significant enough to require modifications to the qualification process, additional evaluation requirements, or a need to reevaluate qualifications of any individual currently qualified for the affected tasks.

(a) Types of change.

These changes may include the following.

- (1) Modifications to operator policies or procedures.
- (2) Changes in state or federal regulations.
- (3) Use of new equipment or technology.
- (4) New information from equipment or product manufacturers.
- (5) Changes needed as a result of monitoring performance or program effectiveness.

(b) Level of communication.

The need to communicate changes will vary depending upon the impact of the change on the covered task. For a change that is not substantive (e.g., does not materially affect the knowledge, skills, or abilities required for a covered task), an operator may decide that communication is not necessary.

(c) Timing of communication.

When the change needs to be implemented may also vary. The use of new equipment could be phased in if continued use of the existing equipment is adequate. This would permit the operator time to provide necessary communications and any required training or additional evaluations without disruption of O&M activities. However, communications related to changes in regulations that result in an existing non-covered operating or maintenance task becoming a covered task may be more urgent since effective dates of new or revised regulations may not provide such flexibility to achieve compliance to the operator qualification requirements. In cases where the operator is aware of an impending rule change (e.g., through monitoring of regulatory projects of the regulating agency), the operator may consider some level of communication prior to the issuance of the final rule (e.g., when a notice of proposed rulemaking is issued).

(d) Type of communication.

The type of communication may also vary based on the impact or complexity of the change. For example, changes that have limited impact or are minor procedural changes may require a simple communication regarding the change (e.g., written or oral communication or briefing). However, changes that are more substantive may require training or an orientation session, and in some cases, may involve additional evaluations. Methods for communication may include the following.

- (1) Written or oral instruction.
- (2) Individual or group meetings.
- (3) Tailgate or pre-job briefings.
- (4) Training sessions.
- (5) Technical mailings.

(e) Documentation of communication.

Operators should document the communications made related to these changes, including the identification of the individuals notified.

2.7 *Evaluation intervals (§192.805(g)).*

(a) The intervals that an operator establishes for the periodic evaluation of qualification (subsequent qualification) may be based on a fixed time interval or on frequency of performance, or other appropriate units. In establishing the appropriate interval, the operator may consider one or more of the following.

- (1) Frequency of task performance.
- (2) Complexity of the task.
- (3) Regulatory requirements.
- (4) Level of risk.

- (5) Accepted industry-related intervals (e.g., NACE, ASNT, and API).
- (6) Other appropriate factors.
- (b) An operator may choose to adopt intervals established by vendors that have expertise in qualification issues. The operator should ensure that the vendor's assumptions are applicable to the operator's situation.

2.8 Training (§192.805(h)).

- (a) The operator should determine the knowledge and skills that are needed to perform covered tasks in a competent manner and focus its training, if needed, accordingly for the individuals who perform a covered task. The operator should consider including the following in its training program.
 - (1) Knowledge of elements of the procedural manual for operations, maintenance, and emergencies that apply to the covered task (see 6 of the guide material under §192.605).
 - (2) Knowledge of pertinent policies, procedures, job methods, materials, maps, and records that apply to the covered task.
 - (3) Knowledge of appropriate abnormal operating conditions.
 - (4) Skills to use the appropriate tools, instruments, and equipment.
 - (5) Skills to perform appropriate actions if abnormal operating conditions are encountered.
- (b) Training may be delivered through methods such as classroom or computer-based instruction, simulation exercises, and on-the-job training. Training aids and publications available from gas industry associations and other sources should be considered in the development of training programs. Such programs may include a review of pertinent accident reports that illustrate and emphasize both good and bad practices.
- (c) Considerations for identifying the need and eventual selection of training program components associated with the identified training need can be found in ASME B31Q, Section 7, "Training."

2.9 Notification of significant modification (§192.805(i)).

The operator should define significant modifications for the purpose of federal or state agency notification, and should consider including any modification that may be viewed as lessening the requirements of the operator's written program. Examples of such modifications could include the following.

- (a) Increase of evaluation interval.
- (b) Deletion of previously identified covered tasks in the program.
- (c) Change in required evaluation methods.
- (d) Increase span-of-control ratios.
- (e) Changes due to mergers or acquisitions.
- (f) Wholesale changes, such as using a third-party plan instead of an operator plan or the adoption of different tasks (e.g., ASME B31Q instead of operator-determined tasks).

§192.807

Recordkeeping.

[Effective Date: 10/26/99]

Each operator shall maintain records that demonstrate compliance with this subpart.

- (a) **Qualification records shall include:**
 - (1) **Identification of qualified individual(s);**
 - (2) **Identification of the covered tasks the individual is qualified to perform;**
 - (3) **Date(s) of current qualification; and**
 - (4) **Qualification method(s).**

(b) **Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.**

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999]

GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

1 RECORDKEEPING

- (a) All records of an individual's qualification to perform a covered task may be maintained at a central location, or at multiple locations.
- (b) Records may be maintained either electronically, as paper copies, or in any other appropriate format.
- (c) If third party data management vendors are used, the records should be readily accessible by the operator.
- (d) The operator does not need to maintain qualification records of contractors provided the contractors are maintaining such records in a manner that meets the requirements of this rule, and the records are available to the operator.
- (e) The operator should be able to produce documentation of qualification for any individual that is performing a covered task on their behalf.
- (f) Records may be kept in any format that would indicate each of the four elements identified in this rule have been addressed.

2 QUALIFICATION CHECK PRIOR TO PERFORMANCE

Prior to performance of a covered task, the operator should ensure that the individuals performing the task or those assigned to direct and observe non-qualified individuals performing the task are documented as being qualified, as required by its written OQ program.

§192.809

General.

[Effective Date: 07/15/05]

(a) Operators must have a written qualification program by April 27, 2001. The program must be available for review by the Administrator or by a state agency participating under 49 U.S.C. Chapter 601 if the program is under the authority of that state agency.

(b) Operators must complete the qualification of individuals performing covered tasks by October 28, 2002.

(c) Work performance history review may be used as a sole evaluation method for individuals who were performing a covered task prior to October 26, 1999.

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

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

[Issued by Amdt. 192-86, 64 FR 46853, Aug. 27, 1999; Amdt. 192-90, 66 FR 43523, Aug. 20, 2001; Amdt. 192-100, 70 FR 10332, Mar. 3, 2005 with Amdt. 192-100 DFR Confirmation, 70 FR 34693, June 15, 2005]

GUIDE MATERIAL

See Cautionary Note at the beginning of Subpart N.

No guide material necessary.

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SUBPART O GAS TRANSMISSION PIPELINE INTEGRITY MANAGEMENT

§192.901

What do the regulations in this subpart cover?

[Effective Date: 02/14/04]

This subpart prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§192.917, 192.921, 192.935 and 192.937 apply.

[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 GENERAL

The requirements of Subpart O apply to all transmission pipelines including compressor stations, metering stations, regulator stations, valve sets, and other fabricated assemblies. The requirements of Subpart O do not apply to distribution lines or to gathering lines.

2 APPLICABILITY OF THIS SUBPART

Table 192.901i identifies the applicability of each section of Subpart O to plastic line pipe, steel line pipe and pipeline components. In the table, "Components" refers to gas-carrying components other than line pipe that are typically above ground, such as compressor stations, meter stations, and regulator stations.

APPLICABILITY OF SUBPART O						
Regulation Section	Natural Gas Transmission Pipeline System					
	Covered Segment (see §192.903)			Non-Covered Segment		
	Plastic Line Pipe	Steel Line Pipe	Components	Plastic Line Pipe	Steel Line Pipe	Components
192.901	R	R	R	R	R	R
192.903	R	R	R	R	R	R
192.905	R	R	R	R	R	R
192.907	R	R	R	C	C	C
192.909	R	R	R	NA	NA	NA
192.911	C	R	R	NA	NA	NA

Legend: R = Required; C = Consider; NA = Not Applicable

TABLE 192.901i

APPLICABILITY OF SUBPART O (Continued)						
Regulation Section	Natural Gas Transmission Pipeline System					
	Covered Segment (see §192.903)			Non-Covered Segment		
	Plastic Line Pipe	Steel Line Pipe	Components	Plastic Line Pipe	Steel Line Pipe	Components
192.913 (if used)	NA	R	R	NA	C	C
192.915	C	R	R	C	R	R
192.917	R	R	R	R	R	R
192.919	C	R	R	NA	NA	NA
192.921	R	R	R	NA	NA	NA
192.923	NA	*	*	NA	*	*
192.925	NA	*	*	NA	*	*
192.927	NA	*	*	NA	*	*
192.929	NA	*	*	NA	*	*
192.931	NA	*	*	NA	*	*
192.933	NA	R	R	NA	C	C
192.935	R	R	R	NA	R	R
192.937	R	R	R	R	R	R
192.939	C	R	R	NA	NA	NA
192.941 (if used)	NA	R	R	NA	C	C
192.943 (if used)	NA	R	R	NA	NA	NA
192.945	C	R	R	C	C	C
192.947	C	R	R	C	C	C
192.951	NA	R	R	NA	NA	NA

Legend: R = Required; C = Consider; NA = Not Applicable
* See guide material under these sections for detailed discussions.

TABLE 192.901i (Continued)

§192.903

What definitions apply to this subpart?

[Effective Date: 03/06/15]

The following definitions apply to this subpart.

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

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

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in §192.3.

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

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

- (1) An area defined as —
 - (i) A Class 3 location under §192.5; or
 - (ii) A Class 4 location under §192.5; or
 - (iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
 - (iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.
- (2) The area within a potential impact circle containing —
 - (i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or
 - (ii) An identified site.
- (3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See Figure E.I.A. in Appendix E.)
- (4) If in identifying a high consequence area under paragraph (1)(iii) of this definition or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy with a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for human occupancy is equal to $20 \times (660 \text{ feet})^2 / \text{potential impact radius in feet}^2$).

Identified site means each of the following areas:

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

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

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

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

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

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S (incorporated by reference, see §192.7) to calculate the impact radius formula.

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

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004, Amdt. 192-95 Correction & Petition for Reconsideration, 69 FR 18228, Apr. 6, 2004 and Amdt. 192-95 Correction, 69 FR 29903, May 26, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

Glossary of Commonly Used Terms and Abbreviations Used in Subpart O

BAP means baseline assessment plan.

CDA means confirmatory direct assessment.

DA means direct assessment.

ECDA means external corrosion direct assessment.

FAQs mean frequently asked questions.

Framework is an early version of an operator's Integrity Management Program (IMP), which does not have all the detailed processes in place.

HCA means high consequence area.

ICDA means internal corrosion direct assessment.

IMP means Integrity Management Program.

Low-frequency ERW (electric-resistance-welded) pipe is pipe that was manufactured using a 250-Hertz (Hz) alternating electrical current to provide heat for fusion of the weld seam. Most pipe made using this process was manufactured prior to 1970.

Low-stress transmission line is a steel transmission line that operates below 30% SMYS.

MOC means management of change.

PIC means potential impact circle.

PIR means potential impact radius.

Plan is a particular component of the overall Integrity Management Program (IMP), and refers to a specific action plan and documented criteria for implementing a particular program element or rule requirement.

Process is a step-by-step logical set of integrated activities that proceed from the initial understanding of what needs to be done, to the successful performance and documentation of results.

Program is a document or a set of documents that systematically defines, controls, and implements integrity management.

SCCDA means stress corrosion cracking direct assessment.

Note: For other terms and abbreviations, see **Glossary of Commonly Used Terms** and **Glossary of Commonly Used Abbreviations** (Table 192.3i) of the guide material under §192.3.

§192.905

How does an operator identify a high consequence area?

[Effective Date: 02/14/04]

(a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (See Appendix E.I. for guidance on identifying high consequence areas.)

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

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

- (i) Visible marking (e.g., a sign); or
- (ii) The site is licensed or registered by a Federal, State, or local government agency;

or

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

(c) *Newly-identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

[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 GENERAL

An operator has three options for determining high consequence areas (HCAs) as illustrated in Figure 192.905A. An operator may use any combination of methods. The operator needs written procedures describing any method used to calculate and document an HCA. An operator may expand HCA boundaries to include additional pipeline footage. For instance, short lengths of pipelines between HCAs may be included in an HCA. See §192.903 for information regarding potential impact circle (PIC) and potential impact radius (PIR).

Flow Chart Illustrating the HCA Determination Process

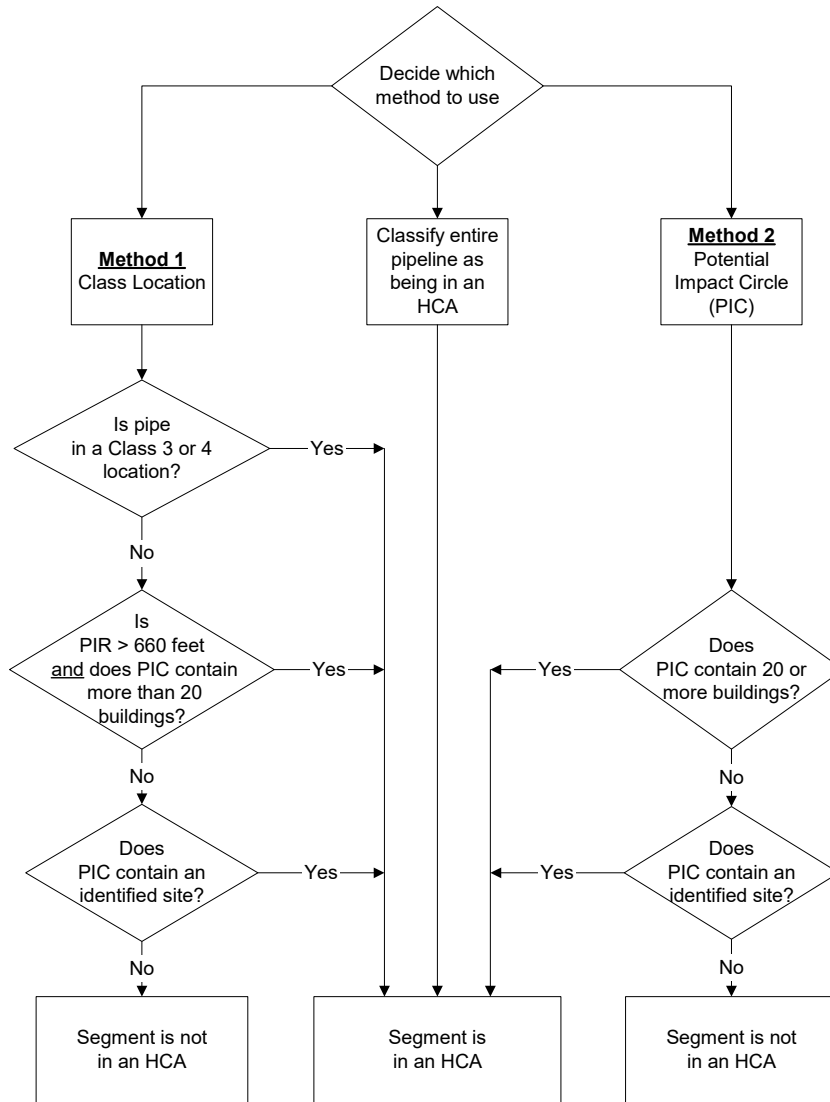


FIGURE 192.905A

2 CHOOSING THE METHOD

Reasons an operator may choose a particular method or other option for determining an HCA are as follows.

2.1 *Method 1 - Class location.*

- (a) Takes advantage of previously defined class location boundaries.
- (b) Reduces the need to calculate potential impact circles.
- (c) Minimizes complexity.
- (d) All class 3 and 4 locations will be an HCA, and performance of the additional preventative and mitigative measures in §192.935(d)(3) is not required.

2.2 *Method 2 - Potential impact circle.*

- (a) Allows the operator to focus resources on locations with higher potential impact.
- (b) Operator has good data on the building locations.
- (c) May reduce the mileage of covered segments.
- (d) Provides a more precise model of potential impact area because it is based on analytical methods.

2.3 *Classify entire pipeline as being in an HCA.*

- (a) Eliminates the need to calculate potential impact circles.
- (b) Eliminates the need to determine identified sites.
- (c) Operator has limited footage of transmission lines.

3 DETERMINATION OF IDENTIFIED SITES

Figure 192.905B illustrates the two processes that must both be used to determine identified sites, i.e., looking for sites while performing O&M activities and contacting public officials. If an operator has determined that an entire pipeline is in an HCA, the operator is not required to look for identified sites.

Flow Chart for Determination of Identified Sites

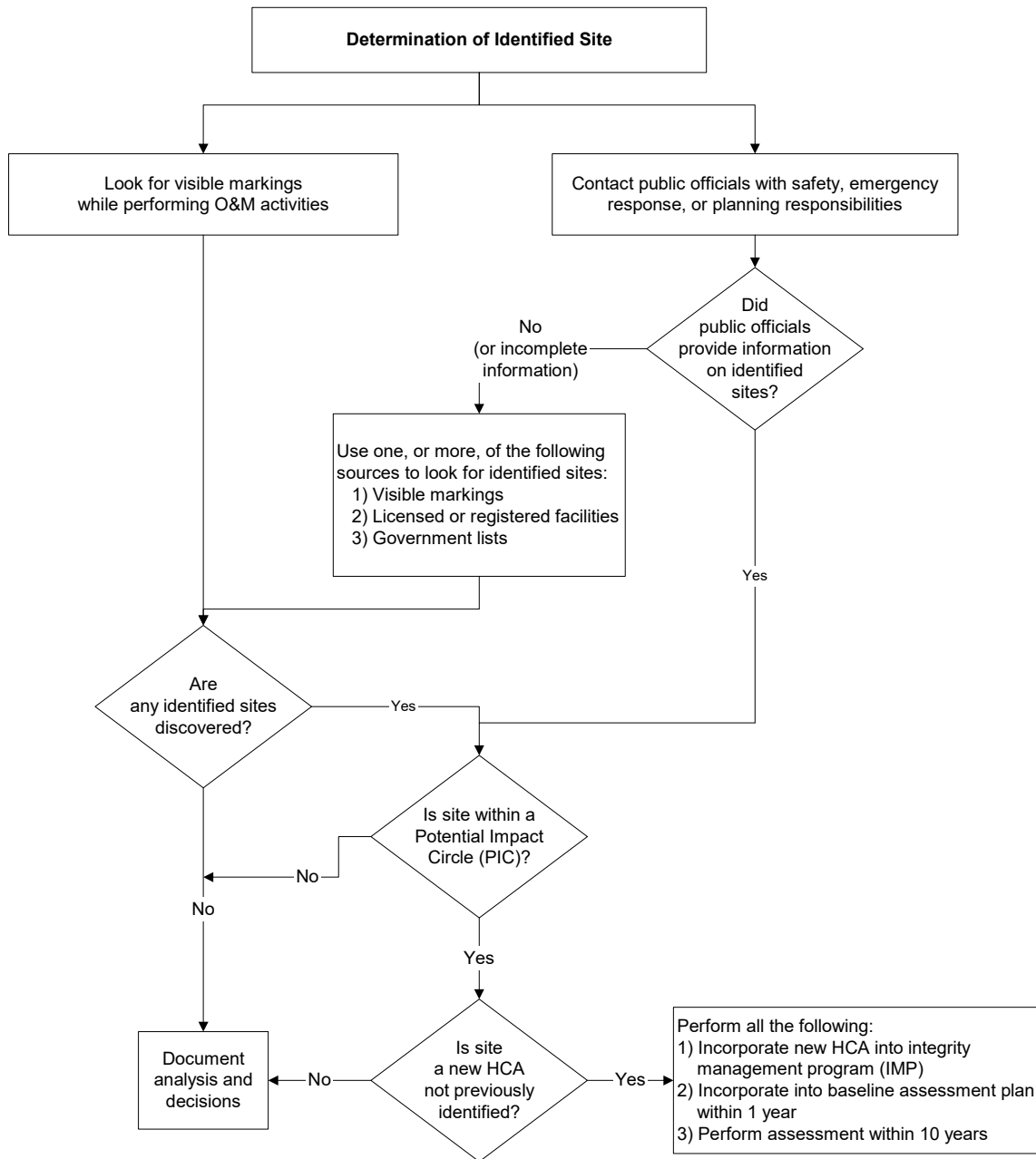


FIGURE 192.905B

3.1 *Public officials.*

- (a) The operator is responsible for contacting public officials with safety, emergency response, or planning responsibilities to obtain information on identified site locations. Appropriate public officials to contact might include the following.
 - (1) Police departments.
 - (2) Fire departments.
 - (3) Local and state emergency coordinators.
 - (4) Local planning and zoning boards.
 - (5) Native American tribal officials.
 - (6) Federal agencies that control land use (e.g., Bureau of Land Management, National Forest Service, military installation).
- (b) If the operator does not know which public officials have responsibilities for safety, emergency response, or planning, consider contacting local, county, or state government offices.
- (c) Operators should consider including the definition of an "Identified Site" in educational material supplied to public officials and emergency response officials. Websites (e.g. www.pipelineawareness.org, www.pipa-info.com) are additional sources of educational training materials about pipelines and identified sites.

3.2 *If public officials do not provide information on identified sites.*

Where information on identified sites is not provided by public officials, or the information is incomplete, the operator must use at least one of the following sources.

- (a) Signs or other visible markings. Signs may also be identified during O&M activities.
- (b) License or registration data. Many government agencies maintain web sites with this information.
- (c) Maps or lists maintained by a government agency that are available to the public.

3.3 *O&M activities.*

O&M activities, such as patrols and leak surveys, provide an opportunity for the operator to discover identified sites. The operator may consider training personnel and revising existing procedures and documentation to incorporate this additional task.

3.4 *Other sources to locate identified sites.*

Some additional sources of information, which may be used to locate identified sites, include the following.

- (a) Commercially available databases.
- (b) Web sites.
- (c) Mapping services.
- (d) Aerial photography.
- (e) Telephone directories.
- (f) Travel guides.
- (g) Chambers of Commerce.
- (h) Professional associations.

4 **NEW OR CHANGED HCAs**

4.1 *Reasons why HCAs might be created, changed, or eliminated.*

- (a) Construction of new homes, buildings, or outdoor places of assembly.
- (b) Abandonment or demolition of homes, buildings, or outdoor places of assembly.
- (c) Increased occupancy of a building or place of assembly.
- (d) Changes in use of structures (e.g., a home converted into a registered daycare facility).
- (e) New pipeline installations.
- (f) Change of product being transported.
- (g) Removing pipeline from service.
- (h) Relocating pipeline.
- (i) Replacing pipe with a different diameter.

- (j) MAOP changes. Pressure increases will expand the potential impact radius and pressure decreases will reduce the potential impact radius. MAOP changes may include the following.
 - (1) Uprating.
 - (2) Class location changes that limit MAOP.
 - (3) Replacing MAOP-limiting pipe or component.
- (k) For some pipelines downstream of a distribution center, the operator may be able to reclassify a pipeline from a transmission line to a distribution line. Some actions, which may be involved in the reclassification, include the following.
 - (1) Substantiating pipeline characteristics (e.g., SMYS or wall thickness) by observation or testing.
 - (2) Lowering the MAOP to a pressure that results in operating at less than 20% SMYS.

4.2 *New HCAs.*

Newly identified HCAs must be incorporated into the IMP. Upon identification of a new HCA, the segment of pipeline within the HCA must be:

- (a) Included in the BAP within 1 year; and
- (b) Assessed within 10 years.

4.3 *Documentation.*

The operator must document changes that affect an existing HCA.

5 REFERENCES

Federal Prisons	www.bop.gov/
Hospitals	http://allhospitals.org
National Parks	www.recreation.gov/
OPS Advisory Bulletin ADB-03-03 (68 FR 42458, July 17, 2003; see Guide Material Appendix G-192-1, Section 2)	www.gpo.gov/fdsys/search/advanced/advsearchpage.action

§192.907

What must an operator do to implement this subpart?

[Effective Date: 07/10/06]

(a) **General.** No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

(b) **Implementation Standards.** In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, see §192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006]

GUIDE MATERIAL

1 WRITTEN PROGRAM

1.1 *General.*

A written program provides a road map for assessment, integration and analysis of data, and courses of action available in managing pipeline integrity. The program can incorporate or reference existing policies and procedures that may address the elements listed in §192.911. The operator should consider conducting a gap analysis between current policies and procedures and the requirements of Subpart O to determine if additional plans, processes, or procedures may be required.

1.2 *Development.*

The operator should consider the following when developing its Integrity Management Program (IMP).

- (a) Existing O&M procedures.
- (b) Existing management systems (e.g., quality assurance and management of change).
- (c) Existing environmental and safety programs.
- (d) "FAQs" from the PHMSA-OPS website at <http://primis.phmsa.dot.gov/gasimp/faqlist.gim>.
- (e) "Inspection Protocols" from the PHMSA-OPS website at:
<http://primis.phmsa.dot.gov/gasimp/prolist.gim>
- (f) Process "Flowcharts" from the PHMSA-OPS website at <http://primis.phmsa.dot.gov/gasimp/>.
- (g) Documents incorporated by reference (see 3 below).

1.3 *References.*

GPTC-Z380-TR-1, "Review of Integrity Management for Natural Gas Transmission Pipelines," an ANSI Technical Report by GPTC, November 18, 2001 (Withdrawn 3/30/12), AGA Catalog Number X69806; available at www.aga.org/GPTC.

2 OPERATORS WITH NO HCAs

Operators that have determined that there are no HCAs should document how that determination was made. The operator must develop a written process for identifying new HCAs. See guide material under §192.905. If HCAs are subsequently discovered, the operator is required to develop an IMP.

3 INCORPORATION BY REFERENCE

3.1 *General.*

- (a) Subpart O requires use of documents that are incorporated by reference (IBR) in §192.7. An operator must meet the requirements of Subpart O and the referenced sections of those documents. In the event of a conflict between ASME B31.8S and NACE SP0502, the more stringent requirement should be followed.
- (b) When developing a written program, an operator needs to consider applicable portions of the following documents that are IBR in §192.7 for Subpart O.
 - (1) ASME B31.8S, which is IBR for this section.
 - (2) Other IBR documents used to develop the elements of an IMP (§192.911):
 - (i) NACE SP0502.
 - (ii) ASME/ANSI B31G.
 - (iii) GRI 02/0057.
 - (iv) AGA, Pipeline Research Committee Project, PR-3-805.

3.2 *ASME B31.8S.*

- (a) This standard contains non-mandatory "should" statements. The operator should evaluate each of these and take appropriate action. The operator may choose alternative practices; however, the operator should document the justification for doing so. Considerations might include the following.
 - (1) Acceptable levels of safety and integrity.
 - (2) Appropriateness to conditions.
 - (3) Technological improvements.
- (b) Appendices A and B2 of this standard are titled as "non-mandatory"; however, the requirements of these appendices are mandatory because Subpart O specifically incorporates them.
- (c) "Must" and "shall" statements in this standard are mandatory.
- (d) References in Subpart O to ASME B31.8S are listed below in Table 192.907i.

SUMMARY OF INCORPORATED REFERENCES TO ASME B31.8S	
ASME B31.8S	Subpart O References
General	§§192.907(b); 192.911; 192.913(a), (b)(1), & (c); 192.935(b)(1)(iv)
Section 2	§192.917(a)
Para 3.2	§192.903 - definition of potential impact radius
Section 4	§192.917(b) & (d)
Section 5	§§192.917(c) & (d); 192.921(a)(2); 192.935(a); 192.937(c)(2); 192.939(a)(1)(ii) & (a)(3)
Para 6.2	§§192.921(a)(1); 192.937(c)(1)
Para 6.4	§§192.923(b)(1) & (b)(2); 192.925(b), (b)(1), (b)(2), (b)(3), & (b)(4); 192.927(b)
Section 7	§192.933(c) & (d)(1)
Section 9	§192.911(i)
Para 9.4	§192.945(a)
Section 10	§192.911(m)
Section 11	§192.911(k)
Section 12	§192.911(l)
Appendix A	§§192.917(b); 192.945(a)
Appendix A2	§192.927(c)(1)(i)
Appendix A3	§§192.923(b)(3); 192.929(b)(1) & (b)(2)
Appendix A3.3	§192.929(b)(1)
Appendix A3.4	§192.929(b)(2)
Appendices A4.3 & A4.4	§192.917(e)(4)
Appendix A7	§192.917(e)(1)
Appendix B2	§§192.923(b)(2); 192.927(b)

TABLE 192.907i

§192.909

How can an operator change its integrity management program?

[Effective Date: 04/06/04]

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

(b) Notification. An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

[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 CHANGES TO BE DOCUMENTED

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

- (a) Information obtained from the integrity assessments.
- (b) Operating experience.
- (c) The operator's understanding about the specific integrity threats and the relative importance of those threats may change.
- (d) The operator's understanding about a specific integrity assessment tool changes, and the operator chooses to use another type.
- (e) Risks are different than previously understood and an operator needs to reprioritize assessments.
- (f) Identification of a new HCA, which adjusts the baseline assessment plan.
- (g) Development of additional program elements.
- (h) Changes in the operating parameters of the transmission pipeline, (e.g., flow reversals, service conversions).

2 NOTIFICATION

When applicable, notification of program changes is required to PHMSA-OPS. In accordance with §192.18 within 30 days after adoption into the operator's IMP. Where PHMSA-OPS has an interstate agent agreement, or an intrastate covered segment is regulated by the state, the operator must also notify the appropriate state or local pipeline safety authority. Where no such agreement exist or the segment is not regulated by that state, the operator may elect to provide an information copy to the state. A reference for state contacts is available at www.napsr.org.

2.1 Changes requiring notification.

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

- (a) An incident on a lower-risk pipeline that would cause a reprioritization of the assessment schedule.
- (b) Changes that affect the way an operator is conducting its IMP, e.g., a change to grading criteria for integrity assessment methods that subsequently affects the inspection, remediation, or prevention and mitigation activities.
- (c) A merger of two companies that causes reprioritization of the assessment schedule under the merged IMP.
- (d) Significant operating changes in transmission pipeline (e.g., flow reversals, service conversions) that would cause a re-prioritization of the assessment schedule or affect the overall manner in which an operator is conducting its IMP.

Notification should include the changes to the program and reasons for such changes. See guide material under §192.18.

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

to a pipeline system and its integrity. MOC is a process for recognizing, evaluating, implementing, communicating, and documenting these changes. Both major and minor changes that impact the integrity of the pipeline, whether permanent or temporary, must be addressed.

3.2 *Types of changes.*

The operator must address changes that fall into four categories: technical, physical, procedural, and organizational. Any single change may affect more than one of these categories. Examples of changes that could impact pipeline integrity are as follows.

- (a) Increase or decrease of MAOP.
- (b) Increase or decrease of maximum operating pressure (see §192.917(e)).
- (c) Changes to cathodic protection systems.
- (d) Changes to criteria, such as grading criteria for ILI, ECDA, or ICDA.
- (e) Discovery of the threat.
- (f) Change in status (i.e, active, inactive) of a threat.
- (g) Corrections to pipeline attributes (e.g., diameter, wall thickness).
- (h) New, remediated, replaced, or re-routed piping or appurtenances.
- (i) Modification of gas quality or composition, such as the following.
 - (1) Propane-air mixture.
 - (2) Vaporized LNG.
 - (3) Biofuels.
 - (4) New production gas.
- (j) Cyclic loading.
- (k) Significant change in operating temperature.
- (l) Flow velocity or direction.
- (m) Documentation from pipe inspections.
- (n) Discovering threats from continuing surveillance (e.g., encroachments, unmonitored activity on ROW).
- (o) Geological events (e.g., subsidence, slips, earthquakes).
- (p) Conversion of service.

3.3 *MOC process components.*

An MOC process includes several components as outlined below. These components ensure that changes that affect the integrity of the pipeline are identified, analyzed, documented, and communicated. *Note:* These components are not required to be completed in the order shown and may be combined with others or may not be applicable.

- (a) Reason for change.

Reason for change begins with the identification of a problem or needed improvement that affects pipeline integrity. Some examples are as follows.

 - (1) To comply with new or revised regulations (e.g., PHMSA, state).
 - (2) To incorporate process improvements or best practices.
 - (3) To improve reliability of pipe or equipment.
 - (4) System optimization.
 - (5) Safety improvements.
 - (6) Changes in technology.
- (b) Authority for approving changes.

The operator should identify the level of authority necessary to approve various types of changes. When approving the change, consideration should be given to seeking input from other affected stakeholders. Some changes may be pre-approved in accordance with an operator's procedure. For example, when a criterion is met for a certain defect, the procedure may authorize repair or replacement of the pipe.
- (c) Analysis of implications.

The operator must evaluate the change and determine the impact to the integrity of the pipeline. The analysis should determine if the change increases or decreases threats to the pipeline.

- (1) If it is determined that the change does impact threats, the operator is required to further analyze the implications of the change and continue to follow the MOC process. These implications could include the following.
 - (i) Data integration.
 - (ii) Training and qualifications.
 - (iii) Procedures.
 - (iv) Public education programs.
 - (v) Available resources (e.g., personnel, equipment, costs).
 - (vi) Changes to the IMP program.
 - (vii) Communication requirements.
 - (viii) Threat analysis.
 - (2) If the change does not impact threats, then no further action is required under the MOC process; however, the change should be evaluated to determine whether it affects the IMP (see guide material under §192.909).
- (d) Acquisition of required work permits.
Examples of permits that might be needed include the following.
- (1) Street opening or public right-of-way.
 - (2) Railroad right-of-way.
 - (3) Private property easements.
 - (4) Environmental (e.g., water removal and runoff, air quality control).
 - (5) Archaeological.
- (e) Documentation.
The MOC process requires changes that affect pipeline integrity be documented (ASME 11(a)). Types of documentation may include the following.
- (1) Forms.
 - (2) Electronic files.
 - (3) Meeting minutes.
 - (4) Memos.
 - (5) Emails.
 - (6) Manual revision logs.
 - (7) Other items identified in the operator's communication plan.
- (f) Communication of change to affected parties.
Changes that impact the integrity of the pipeline are required to be communicated to affected parties (ASME 11(a)) and consideration should be given to communicate the change in accordance with the operator's communication plan (ASME 10).
- (1) Examples of affected parties include the following.
 - (i) Employees.
 - (ii) Management.
 - (iii) Contractors.
 - (iv) Regulatory agencies.
 - (v) Local agencies.
 - (vi) The public.
 - (2) Examples of what might be communicated include the following.
 - (i) Description of change.
 - (ii) Duration of change (permanent versus temporary).
 - (iii) Urgency of change.
 - (iv) Affected personnel.
 - (v) Affected pipeline system.
 - (vi) Affected procedure.
 - (vii) Parties responsible for implementing the change.
 - (3) Examples of how changes can be communicated include the following.
 - (i) Work management system.
 - (ii) Maps or drawings.
 - (iii) Training.

- (iv) Meeting minutes.
 - (v) Memo.
 - (vi) Email.
 - (vii) Internet or intranet.
 - (viii) Manual revision or log.
- (4) Some changes might need to be communicated immediately while others, such as mapping upgrades, might be communicated on a periodic basis.
- (g) Time limitation.
To ensure immediate needs are addressed in a timely manner, the request for change should indicate the level of urgency. Time related factors related to a change might include the following.
- (1) Effective date.
 - (2) Expiration date.
 - (3) Permanent or temporary.
 - (4) Communication timeframe.
 - (5) Regulatory compliance dates (e.g., repair of a dent).
 - (6) Permit requirements.
 - (7) Training and qualification completion.
- (h) Qualification of staff.
The operator is required to evaluate whether the change impacts the qualification of staff (ASME 11(a)). Consideration should be given to the following.
- (1) Does the change add new qualification requirements?
 - (2) Does the change require refresher training?

3.4 Examples.

- Example 1 - A plug valve is going to be replaced with a ball valve to accommodate an In-Line Inspection (ILI). The replacement of a plug valve allows for the passage of pigging equipment, thus allowing the assessment type to be changed from direct assessment or pressure testing to ILI. This valve replacement is a change to the pipeline system and, therefore, must be addressed in the MOC process.

Note: "Responses" for this example are shown in italics.

- (a) Reason for change — *New valve installed to accommodate ILI.*
- (b) Authority for approving changes — *Valve has been authorized by management.*
- (c) Analysis of implications:
 - (1) Data integration — *Need to update records and maps.*
 - (2) Training and qualifications — *Personnel are trained and qualified for this type of valve.*
 - (3) Procedures — *O&M procedures for this type of valve are in place and changes are not needed.*
 - (4) Public education programs — *No changes are necessary.*
 - (5) Available resources (e.g., personnel, equipment, costs) — *Valve, equipment, and personnel are available.*
 - (6) Changes to the IMP program — *Yes, assessment method to be changed.*
 - (7) Communication requirements — *Normal O&M procedures.*
 - (8) Threat analysis — *No change in threats.*

Based upon the analysis of this change, it is determined that the installation does not affect the pipeline integrity because there are no changes in the threats to this pipeline. Therefore, it is not necessary to complete the steps beyond the "analysis of implications" component. Since this change is intended to affect the IMP because of the change in the assessment method, the operator is required to address this change under §192.909 and document this analysis per §192.947.

- *Example 2* – A dent is discovered as a result of an ILI. Based upon initial analysis of the data, the dent is classified as an immediate repair condition in accordance with §192.933.

Note: "Responses" for this example are shown in italics.

- (a) Reason for change — *Dent identified.*
- (b) Authority for approving changes — *Repair procedure describes authorization to repair by composite sleeve.*
- (c) Analysis of implications:
 - (1) Data integration — *Need to update records and maps.*
 - (2) Training and qualifications — *Personnel are trained and qualified for this type of repair, but due to extended time, refresher training and evaluation is recommended.*
 - (3) Procedures — *O&M procedures for this type of sleeve are in place and changes are not needed.*
 - (4) Public education programs — *No changes are necessary.*
 - (5) Available resources (e.g., personnel, equipment, costs) — *Need to order sleeve, but equipment and personnel are available.*
 - (6) Changes to the IMP program — *Maybe, depending on the information gathered during the exposure of the pipeline and the potential change to risk weighting.*
 - (7) Communication requirements — *Appropriate personnel.*
 - (8) Threat analysis — *To be determined based upon information obtained after the pipe has been exposed.*

Based upon the analysis of this change, it is determined that the known condition of the dent affects the integrity of the pipeline; therefore, it is required to complete the remaining MOC steps.

- (d) Acquisition of required work permits — *No permits are required based upon location.*
- (e) Documentation — *Existing procedures provide documentation requirements.*
- (f) Communication of change to affected parties:
 - (1) Affected parties — *Employees and management.*
 - (2) Information to be communicated:
 - (i) Description of change — *Repair dent.*
 - (ii) Duration of change (permanent versus temporary) — *Permanent.*
 - (iii) Urgency of change — *Completed by next Tuesday.*
 - (iv) Affected personnel — *Plant personnel in District D.*
 - (v) Affected pipeline system — *Mile Post 63+48 of Line 101.*
 - (vi) Affected procedure — *Procedure 4.6.2, Installation of a composite sleeve.*
 - (vii) Parties responsible for implementing the change — *IMP Team.*
 - (3) How changes are going to be communicated — *Email.*
- (g) Time limitation:
 - (1) Effective date — *9/10/08.*
 - (2) Expiration date — *9/15/08.*
 - (3) Permanent or temporary — *Permanent.*
 - (4) Communication timeframe — *9/10/08.*
 - (5) Regulatory compliance dates (e.g., repair of a dent) — *Repair within 5 days.*
 - (6) Permit requirements — *None.*
 - (7) Training and qualification completion — *9/12/08.*
- (h) Qualification of staff:
 - (1) Does the change add new qualification requirements? — *No.*
 - (2) Does the change require refresher training? — *Yes.*

3.5 Effects of IMP and pipeline system changes.

It should be recognized that changes in the IMP could cause changes to the integrity of the pipeline; in turn, pipeline system changes might cause changes in the IMP. ASME 11 provides several examples. Table 192.911i shows some additional examples that initiate the use of the formal MOC process.

	IMP CHANGE THAT AFFECTS PIPELINE	PIPELINE CHANGE THAT AFFECTS THE IMP
Technical	An assessment of a pipeline may drive a reduction in MAOP.	Lowering the MAOP on a pipeline may cause a reduction or elimination of an HCA within the BAP and a change in assessment intervals. (<i>Note:</i> Lowering below 20% SMYS may remove the IMP requirements.)
Physical	Because of repeated failures of XYZ valves, all XYZ valves are removed and replaced.	A found threat on a pipeline may cause a review of "like" pipelines which may increase the risk ranking of HCAs.
Procedural	A desired assessment method may require a change to a pipeline.	The installation of a valve may now allow a different assessment method and procedures to be used.
Organizational	New management changes IMP to use ILI on all pipelines. Pipelines must be made piggable.	The acquisition of an additional transmission company might result in the operator combining programs and re-ranking all pipelines.

TABLE 192.911i

4 QUALITY ASSURANCE / QUALITY CONTROL

4.1 General.

Among the several program elements of §192.911 is a "quality assurance process" that meets the requirements of ASME 12, "Quality Control Plan." In general business terms, *Quality Assurance* (QA) and *Quality Control* (QC) are individual steps in a QA/QC process. QA typically refers to an end result and involves a practice of continual monitoring to ensure that the desired end results are being met. QC, on the other hand, typically refers to the review of individual steps in a process that looks at *who, what, when, where, and why* or *why not*.

4.2 Quality control plan requirements.

As defined in ASME 12, quality control is "documented proof that the operator meets all the requirements of their integrity management program." That section addresses basic quality control plan requirements, which include aspects of both QA and QC. In accordance with ASME 12.2, the following six activities are usually required.

- (a) Identify the processes that will be included in the quality program.
- (b) Determine the sequence and interaction of these processes.
- (c) Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective.
- (d) Provide the resources and information necessary to support the operation and monitoring of these processes.
- (e) Monitor, measure, and analyze these processes.
- (f) Implement actions necessary to achieve planned results and continued improvement of these processes.

Details of these six activities are discussed below. Operators may use an existing QC program providing it meets or exceeds the requirements of ASME 12.

4.3 Activity details.

- (a) Identify the processes that will be included in the quality program (ASME 12.2(a)(1)).
All the processes, or elements, associated with the IMP are subject to QC. The operator should include the documentation requirements for each element of the IMP (ASME 12.2(b)(1)). Examples of these documents include the following (see 4.4 below).
- (1) Integrity management plan.
 - (2) Potential Impact Radius (PIR) data.
 - (3) HCA listings.
 - (4) HCA changes.
 - (5) Risk rankings.
 - (6) Risk-ranking verification.
 - (7) Integrity assessments.
 - (8) Remediation records.
 - (9) Communication records.
 - (10) Change management records.
 - (11) Completed activity reports (recordkeeping).
- (b) Determine the sequence and interaction of the processes (ASME 12.2(a)(2)).
The order in which integrity-related activities are performed should be established to ensure that the activities are not undertaken out of sequence or without approval as required by the operator's IMP. Examples of sequencing include the following.
- (1) HCA identification should be completed and verified prior to performing threat identification.
 - (2) Threat identification data gathering and integration should be completed before execution of risk analysis.
 - (3) Risk analysis should be completed in advance of updating the assessment schedule.
- (c) Determine the criteria and methods needed to ensure that both the operation and control of the processes are effective (ASME 12.2(a)(3)).
- (1) *Criteria.* In general, the criteria involve comparing the actions required in the IMP to the implementation and results. Typically, these will involve looking at *who*, *what*, *when*, *where*, and *why*.
 - (i) *Who.* Section 192.915 requires that persons carrying out assessments, evaluating assessment results, or responsible for preventative and mitigative measures be qualified. ASME 12.2(b)(2) states that "responsibilities and authorities under the program shall be clearly defined." The QC process should include verification that responsibilities are clearly defined, and that persons who perform integrity management tasks are qualified.
 - (ii) *What.* The IMP consists of processes and plans. The QC process should monitor the implementation of the IMP to verify that the process is being followed. As a QA step, the analysis should, at a minimum, compare the IMP plan to the regulatory requirements to verify that they are being met.
 - (iii) *When.* The Regulations require that actions be completed within certain time frames (§§192.905(c), 192.933, and 192.937). The operator's IMP will also contain schedules and deadlines. The QC process should compare the actual completion dates with the required completion dates.
 - (iv) *Where.* To perform data integration on covered segments, pipeline locations and HCA boundaries need to be accurately identified. The QC process should review pipeline maps and other spatial data to confirm that HCA boundaries are correct.
 - (v) *Why.* Decision making is part of the IMP. For example, an operator must decide on an assessment method to be used and on preventative and mitigative measures to be implemented. The QC program should verify that decisions are documented and include the reasons why an option was chosen or rejected.
 - (2) *Methods.* A structured review of the program is a common method for ensuring that processes are effective. Such a review includes the following.
 - (i) Periodic internal audits (ASME 12.2(b)(6)). An operator should establish the frequency for conducting internal reviews based on the size and complexity of its organization. The operator should also consider items that might trigger an internal review, including the

- following.
- (A) After large-scale organizational, facility, or program changes.
 - (B) When performance metrics do not meet expectations.
 - (C) Prior to scheduled regulatory inspections.
 - (D) After pipeline failures on assessed pipelines.
 - (E) Periodically to ensure performance metrics are meeting expectations.
- (ii) External reviews. An independent third-party review of the IMP may provide a fresh perspective on an operator's program. External reviews might be considered when an operator does not have sufficient internal resources to perform an internal review, or when internal reviews are not effective at improving performance.
 - (iii) Regulatory inspections. Regulatory agencies provide an independent review of the program. Section 192.911(m) requires operators to have procedures for responding to safety concerns raised by regulatory agencies, and an operator may reference these procedures or include them as part of its QC plans.

For tools that might be used during the review, see 4.3(d)(2) below.

- (d) Provide the resources and information necessary to support the operation and monitoring of the processes (ASME 12.2(a)(4)).

Resources and information include the following.

- (1) The personnel the operator uses to support and monitor the IMP may be employees or contractors. Guidance for personnel requirements are provided in 4.3(c)(1)(i) above.
 - (2) Tools that support the operation and monitoring of the integrity processes include the following.
 - (i) Dedicated integrity management software.
 - (ii) OQ systems.
 - (iii) Electronic document management systems.
 - (iv) Calendars/email.
 - (v) Work order systems.
 - (vi) Quality management systems.
 - (vii) Checklists or forms. PHMSA provides copies of their audit protocols on their website (<http://primis.phmsa.dot.gov/gasimp/documents.htm>).
 - (3) Information necessary to support the operation and monitoring might include the following.
 - (i) Procedures.
 - (ii) Processes.
 - (iii) Records.
- (e) Monitor, measure, and analyze the processes (ASME 12.2(a)(5)).
ASME 12 states "the operator shall determine how to monitor the integrity management program to show that it is being implemented according to plan and document these steps. These control points, criteria and/or performance metrics shall be defined."

- (1) *Monitor and control points.* Monitoring may be conducted using the criteria, methods, and resources described in 4.3(c) and (d) above. As appropriate, the IMP should include control points to determine if the next step should be taken. For example, in the threat analysis process, a control point is the determination of whether there is sufficient data available to analyze the threat. If so, the process can continue to the risk analysis step. If the data is not sufficient, then steps should be taken to either collect additional data or use conservative estimates.
- (2) *Measures.* Implementation measures to be monitored might include the following.
 - (i) Recordkeeping. Identification and documentation of specific occurrences where IMP requirements are not met.
 - (ii) On-time completion. Verification and documentation of IMP compliance with Subpart O and state pipeline safety agency expectations, where applicable.
 - (iii) Corrective actions. Timely implementation of corrective actions in addressing noncompliance concerns.
 - (iv) Communications. Verification and documentation that communications have been made.
 - (v) Change management. Number of changes made and non-compliance trends, which

may indicate inadequate procedures or process controls.

- (vi) Internal QA. Periodic assessment of the effectiveness of the auditing process in advancing the goals of QA.

Performance measures (see guide material under §192.945) are used to evaluate the overall effectiveness of the IMP.

- (3) *Analysis*. Results of the IMP and the QC program shall be reviewed at predetermined intervals and recommendations should be made for improvement, as applicable. (See ASME 12.2(a)(3).) A mechanism should be in place to manage improvements if corrective actions are identified. The operator may change the frequency of the predetermined interval based on the findings.

- (i) Performance management requires the improvement of, or change in, the processes (i.e., activities) if it is determined that the results are not meeting the IMP objectives. Quality controls allow for the determination of which processes have and have not been properly implemented.

- (ii) Conversely, performance management may require changes to the quality controls if the results are not meeting the IMP objectives because the processes are not being properly implemented (i.e., controlled).

- (iii) The analysis should address the following.

- (A) Determine whether the activities and processes are implemented according to the IMP. The implementation includes oversight and approvals.

- (B) Determine whether the IMP performance measures meet expectations. For example, if analysis of leak data indicates internal corrosion as the leading leak cause but the risk model indicates external corrosion as the most probable threat, then the risk model and P&M measures should be reviewed and updated accordingly.

- (C) Compare trends of current data to historical data.

- (D) Compare the operator's performance measures with industry data.

- (f) Implement actions necessary to achieve planned results and continued improvement of the processes (ASME 12.2(a)(6)).

ASME 12 requires corrective action when deficiencies in the IMP have been identified (ASME 12.2(a)(3)). It also requires that the corrective action be documented and the effectiveness of its implementation monitored (ASME 12.2(b)(7)). The "Management of Change" process (see 3 above) can be used to document the corrective actions. Subsequent monitoring and analysis should be used to determine if the change was effective.

4.4 *Documentation*.

ASME 12 requires operators to keep records of IMP activities and to document the decisions and processes used in developing and implementing an IMP (§192.947). By the ASME definition, "quality control" requires that operators have "documented proof," and the QC plan should provide for adequate documentation. Since QC is part of the IMP, records must also be kept of the QC process. The QC plan should review document access and control including who has the authority and capability to edit, remove, or delete documents or records. The need for backup records should also be reviewed. For additional guidance on required documentation, see guide material under §192.947.

5 SAFETY AND ENVIRONMENTAL CONSIDERATIONS

5.1 *General*.

Section 192.911(o) requires procedures to ensure that assessments are conducted in a manner that minimizes safety and environmental risks. Operators may reference or incorporate existing safety and environmental procedures into the IMP.

5.2 *Pressure testing*.

For safety and environmental considerations during pressure testing, see guide material under §192.515.

5.3 In-line inspection.

For environmental and safety considerations when conducting an ILI, see Guide Material Appendix G-192-14.

5.4 Direct assessment surveys.

If direct assessment is being used as an assessment method, operators should consider addressing the following in their procedures.

- (a) Precautions for working near high-voltage AC power lines.
- (b) Requirements for grounding.
- (c) Precautions for dealing with severe weather, such as thunderstorms.
- (d) Precautions for dealing with traffic.

5.5 Excavation and examination of buried pipe.

All forms of assessment may require excavation and examination of pipe. The IMP should include or reference procedures for the following.

- (a) Taking precautions to protect personnel in excavated trenches (see guide material under §192.605).
- (b) Determining safe pipeline pressure prior to excavation.
- (c) Excavation and trenching (see 29 CFR Part 1926 Subpart P).
- (d) Confined space entry (see 29 CFR Part 1910.146).
- (e) Dealing with contaminated soils.
- (f) Removing and disposing of materials containing asbestos.

§192.913

**When may an operator deviate its program from
certain requirements of this subpart?**

Effective Date: 07/10/06]

(a) **General.** ASME/ANSI B31.8S (incorporated by reference, see §192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

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

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

- (i) A comprehensive process for risk analysis;
- (ii) All risk factor data used to support the program;
- (iii) A comprehensive data integration process;
- (iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;
- (v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;
- (vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;
- (vii) Semi-annual performance measures beyond those required in §192.945 that are part

of the operator's performance plan. (See §192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951; and

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

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

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

(ii) Remediate all anomalies identified in the more recent assessment according to the requirements in §192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

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

(1) The time frame for reassessment as provided in §192.939 except that reassessment by some method allowed under this subpart (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in §192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

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GUIDE MATERIAL

No guide material necessary.

§192.915

What knowledge and training must personnel have to carry out an integrity management program?

[Effective Date: 02/14/04]

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

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

(1) Who conducts an integrity assessment allowed under this subpart; or

(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or

(3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person —

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or

(2) Who directly supervises excavation work carried out in conjunction with an integrity

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

This guide material is under review following Amendment 192-132.

Note: References to ASME B31.8S throughout this section of guide material are specific to the edition of ASME B31.8S as incorporated by reference (IBR) in §192.7. Section 192.917(b) requires that the operator comply with the IBR edition of ASME B31.8S, Appendix A even though Appendix A is titled as "non-mandatory." See 3.2 of the guide material under §192.907.

1 GENERAL

- (a) Threats are analyzed to determine which threats may contribute to the failure of a pipe segment, which assessment techniques are appropriate, and which preventative and mitigative measures should be implemented. Threat analysis requires data integration and allows for the prioritization of both assessments and mitigation measures (§192.917(b)). Operators should develop processes to ensure information acquired about both covered and non-covered segments is considered in determining risk and appropriate preventative and mitigative measures.
- (b) Section 192.917(b) requires that operators using a prescriptive-based program consider the information within ASME B31.8S, Appendix A. When gathering data to meet ASME B31.8S, Appendix A, if the operator is missing data, conservative assumptions should be used and documented. Operators using a performance-based program must meet or exceed the prescriptive-based program data requirements per §192.913(b).
- (c) An operator must consider all threats per ASME B31.8S in its IMP.
- (d) An operator may be active or inactive for a specific risk assessment; however, threats to a pipeline may change. The operator's IMP should include provisions for re-analysis of the threat categories periodically to determine status changes.
- (e) An operator should continually monitor operations and maintenance (O&M) and other activities, integrating relevant information during a threat analysis that might indicate a change in the status of a threat. Communication between O&M and integrity personnel is a key component to evaluating threats.
- (f) In the following guide material, Sections 2 through 11 deal with threats to steel transmission pipelines. Section 12 deals with threats to plastic transmission pipelines. Section 13 addresses data integration, Section 14 addresses threat status, Section 15 addresses risk assessment, and Section 16 provides a list of references.

2 IDENTIFICATION OF THREATS TO STEEL PIPELINES

Section 192.917(a) requires operators to address potential threats to pipeline integrity. See 16.1.1 below for reference containing a representative list of pipeline threats that includes examples and comments. Threats for steel pipelines are commonly grouped into the following categories.

- (a) Time-dependent.
- (b) Stable.
- (c) Time-independent.
- (d) Other.

2.1 *Time-dependent threats.*

Time-dependent threats are those that may grow more severe over time, such as corrosion. Analysis based on sound engineering practices may be used to help predict when these threats might become critical. Corrosion threats include the following.

- (a) External corrosion.
- (b) Internal corrosion.
- (c) Stress corrosion cracking.

2.2 *Stable threats.*

A threat that has passed post-construction testing is considered stable. However, these stable threats may change as external factors (e.g., loading due to earth movements, temperature changes, pressure changes) act upon it. These threats include the following.

- (a) Manufacturing defects.

- (b) Welding and fabrication (construction) defects.
- (c) Equipment failures.

2.3 *Time-independent threats.*

Time-independent threats are generally associated with events that may take place along the pipeline segment and can happen at any time. These threats include the following.

- (a) Excavation damage.
- (b) Incorrect operations (includes human error).
- (c) Weather-related and outside force.

Note that §192.917 identifies "Human Error" as a fourth threat category. This guide material follows the ASME B31.8S threat categories and addresses the human error threat in conjunction with the incorrect operations threat.

2.4 *Other threats.*

Section 192.917(a) requires operators to analyze the pipeline for other threats that may not fit into one of the above categories.

3 EXTERNAL CORROSION

In evaluating the threat of external corrosion, ASME B31.8S, Appendix A1 provides a list of data that the operator is required to gather and evaluate. This threat applies to both belowground and aboveground installations.

3.1 *Year of installation.*

Since the threat is time dependent, the threat may increase the longer the pipe is in service. If the installation year is not known, conservative estimates should be used.

3.2 *Coating type.*

While coated pipe is generally less susceptible to external corrosion, all coatings are not equally effective. The coating application method should also be considered when determining the existence and severity of the external corrosion threat. For example, a field-applied coating may not have the same performance as a mill-applied coating of the same type. Bare pipe may be considered as a coating type of "none."

3.3 *Coating condition.*

The following should be considered in evaluating the coating condition.

- (a) Findings from prior assessments.
- (b) Data from close-interval survey (CIS) and coating surveys.
- (c) Data from pipeline inspection reports.
- (d) Leak data.
- (e) Data from atmospheric corrosion reports.
- (f) Changes in cathodic protection current levels.
- (g) Evaluation of coating under insulation.

3.4 *Cathodic protection.*

Cathodic protection (CP) can greatly reduce the potential for external corrosion on buried facilities. The following should be considered.

- (a) Years that the pipeline operated before CP was installed.
- (b) Type of CP system (i.e., galvanic, impressed current, or none).
- (c) Dates of major CP changes (e.g., additional rectifiers and ground beds installed).
- (d) Effectiveness of the CP system.
- (e) Rectifier inspection records to determine if the segment has had any significant changes in protective current requirements.

3.5 *Soil characteristics.*

Typical soil characteristics that may influence the threat of external corrosion include the following.

- (a) Soil resistivity.
- (b) Soil pH.
- (c) The existence of certain bacteria.

See 16.1.2 below for a reference on soil characteristics and corrosion.

3.6 *Pipe inspection reports.*

Pipe inspection reports provide documentation that external corrosion existed or did not exist on buried piping at the excavation site. The report may also provide data on the following.

- (a) Coating type and condition.
- (b) Effectiveness of the CP system.
- (c) Soil characteristics.
- (d) Presence of bacteria.
- (e) Type of corrosion (e.g., isolated pits, general corrosion).
- (f) Depth of corrosion and remaining wall thickness.
- (g) Root cause of external corrosion.

Atmospheric corrosion inspection reports may provide information similar to (a), (e), and (f).

3.7 *History of microbiologically influenced corrosion (MIC).*

The existence of bacteria can create conditions that are corrosive to steel. MIC can still occur even if pipe-to-soil potentials meet criteria.

3.8 *External corrosion leak history.*

Leak history and trends are important factors in assessing the threat of external corrosion.

3.9 *Wall thickness.*

Thicker wall pipe will allow more corrosion tolerance, but the degree of additional tolerance may vary depending on the actual operating conditions.

3.10 *Pipe diameter.*

As pipe diameter increases, the amount of cathodic protection current needed to protect the pipe also increases. This is especially true for bare pipelines. Pipe diameter is also a factor in determining operating hoop stress.

3.11 *Operating stress level.*

Operating stress level is a key factor in predicting failure mechanisms and determining the tolerance to external corrosion. Flow reversal might change the pressure gradient of a pipeline by affecting the operating stress level at different points along the pipeline. The effect of new pressure gradient on existing defects should be evaluated.

3.12 *Prior assessments.*

Evaluating the findings from prior assessments (e.g., in-line inspection, pressure tests, external corrosion direct assessment) and resulting remedial actions can provide useful data in determining the threat of external corrosion. Consider results from both covered and non-covered segments in evaluating external corrosion threats for other pipeline segments with similar coating and environmental characteristics.

3.13 *Other considerations.*

In addition to the data elements listed in ASME B31.8S, Appendix A1, the following data may be useful in evaluating external corrosion.

- (a) Electrical shorts (e.g., casings, other metallic structures).
- (b) Stray current.
- (c) Interference bonds.
- (d) Electrical current mitigation devices.
- (e) Areas previously identified as active corrosion areas.
- (f) Areas where electrical surveys are impractical (e.g., bare pipe, ineffectively coated pipe). See guide material under §192.465.
- (g) Selective seam corrosion (sometimes referred to as preferential seam corrosion) is corrosion across or adjacent to longitudinal seams and is most prevalent in electric-resistance-welded (ERW) pipe.
- (h) Incident and safety-related condition reports related to external corrosion.

4 INTERNAL CORROSION

In evaluating the threat of internal corrosion, ASME B31.8S, Appendix A2 provides a list of data that the operator is required to gather and evaluate. Although the operator is required to collect the following data, covered segments may not be susceptible to the threat of internal corrosion if any pipeline inclination angle greater than a critical angle exists upstream of the covered segment. For guidance in determining the critical angle and the pipeline inclination angle, see 5.1, 5.2, and 5.3 of the guide material under §192.927.

4.1 *Year of installation.*

Since the threat is time-dependent, the threat may increase the longer the pipe remains in service. If the installation year is not known, conservative estimates should be used.

4.2 *Pipe inspection reports.*

Internal pipe inspection reports provide documentation regarding the presence of internal corrosion. The location of the internal corrosion may indicate the mechanism of corrosion (pits at the top of the pipe indicate a more vapor driven mechanism caused by high dew points that allow condensation of water, while pitting along the bottom of the pipe indicates the presence of liquid water; see guide material under §192.476). Changes in pipe direction may be prone to erosion corrosion. See 16.1.3 below.

4.3 *Internal corrosion leak history.*

Leak history, trends, and leak locations are factors in determining the susceptibility of the internal corrosion threat and may provide information regarding low spots or liquid hold-up locations, and the presence of internal corrosion on longitudinal seams. Flow reversals might alter future internal corrosion evaluations and assessments on pipelines due to potentially new liquid hold-up locations.

4.4 *Wall thickness.*

Thicker wall pipe will allow more corrosion tolerance, but the degree of additional tolerance may vary depending on the actual operating conditions.

4.5 *Pipe diameter.*

Changes in pipe diameter may cause changes in flow characteristics (e.g., turbulent or laminar flow, venturi effect) and velocity, which may allow liquid water to drop out.

4.6 *Prior assessments.*

Evaluating the findings from prior assessments (e.g., in-line inspection, pressure tests, internal corrosion direct assessment) and resulting remedial actions can provide useful data in determining the threat of internal corrosion.

The risk of internal corrosion could increase after hydrostatic testing due to the following.

- (a) Water or debris left in the pipeline after hydrostatic testing.

- (b) The test water contains bacteria that promote MIC.

4.7 *Gas, liquid, and solid sampling analysis.*

Analysis of gas, liquid, and solid samples can be used to help determine the probability of internal corrosion and help identify the cause of corrosion. Data should be trended to determine if values are increasing or decreasing.

- (a) Gas. When analyzing for internal corrosion, partial pressures (see 4.10 below) and gas chemistry are important considerations. Typical gas analysis should include the determination of the following constituents.
- (1) *Carbon dioxide (CO₂)*. CO₂ in the gas can mix with water in the gas stream to form carbonic acid, which is corrosive to steel. The percentage of CO₂ in the gas stream can be determined by using a stain tube or analyzing the sample by gas chromatography. CO₂ partial pressure below 3 psia is generally considered non-corrosive. See 16.1.4 and 16.1.5 below. The table below identifies typical concern levels for CO₂ partial pressures.

CO ₂ Partial Pressure (psia)	Level of Concern
< 3	Low Risk
3 – 30	Moderate Risk
> 30	High Risk

TABLE 192.917i

- (2) *Hydrogen sulfide (H₂S)*.
- (i) H₂S may be a normal constituent in natural gas, and can also be formed due to MIC. H₂S will combine with water to form a weak sulfuric acid which is corrosive to steel. The presence of H₂S may also cause hydrogen blistering and sulfide stress cracking.
- (ii) The amount of H₂S in the gas stream may be determined by using a stain tube or an electronic meter. The stain tube typically provides a read out in ppm which, if necessary, is then converted to percentage. Electronic meters give a direct reading of the percent of H₂S in the gas.
- (iii) A typical operator-set tariff range for H₂S is between 4 and 16 ppm. Gas maintained at tariff quality is considered a low concern for internal corrosion caused by H₂S.
- (3) *Oxygen (O₂)*. O₂ is often present in small amounts in natural gas and, when present in a gas stream containing water, can act as a catalyst to speed up general and pitting corrosion. O₂ can be measured with a stain tube or by gas chromatography. If O₂ is indicated, the dissolved O₂ concentration in water should be calculated. A dissolved O₂ concentration above 10 to 50 ppm is considered corrosive to steel pipelines.
- (4) *Water content or dew point*. For corrosion to occur there must be an electrolyte, such as water, present to react with the gas constituents. High dew points may allow water to condense at certain locations and activate corrosion mechanisms. Water content in the gas stream can be measured with either a stain tube or an electronic meter. Both devices determine the amount of water in pounds per million cubic feet (lbs/MMSCF) of the gas. A value of less than 7 lbs/MMSCF is generally considered non-corrosive. At higher concentrations and certain pressure and temperature conditions, it is possible for water vapor to condense.
- (b) Liquid. For evaluating internal corrosion, only liquids containing electrolytes need to be analyzed. Non-electrolytes, such as drip gas and other hydrocarbons, may not need to be analyzed because they do not contribute to corrosion. Water indicators are available to determine if the sample contains electrolytes. When analyzing for internal corrosion, a typical liquid analysis includes the following.
- (1) *pH*. The pH measures the acidity or alkalinity. A pH of 7 is neutral. A reading of less than 7 is acidic, with lower numbers indicating a stronger acid. Readings above 7 are alkaline,

with higher numbers indicating a stronger base. Readings near neutral represent less corrosive liquids. Low pH levels, such as 5.0 or less, may result in increased corrosion.

- (2) *Iron or manganese.*
 - (i) Iron might exist naturally in liquids in small amounts. Manganese is not normally present in liquids produced from natural gas sources, but is present in steel.
 - (ii) Iron concentrations above 2500 ppm or manganese concentrations above 25 ppm may indicate corrosion of steel. A manganese to iron ratio between 1:50 and 1:200 may indicate the source of iron is from corrosion. Deviations from this ratio range could indicate the presence of other material or other chemical mechanisms. See 16.1.6 below.
 - (iii) Due to precipitation of iron from the liquid sample, a lower iron concentration in solution may not indicate a reduced rate of corrosion. Proper handling of samples should be ensured to prevent precipitation.
 - (iv) When analyzing iron and manganese counts, the system parameters (e.g., flow rate, amount of water, temperature) should be reviewed and scaling tendency should be determined.
- (3) *Salt or chlorides.* Salt, or more specifically chloride, is not in itself corrosive. Water containing chlorides or other salts tend to be more corrosive than fresh water. The type and concentration of anions in the sample can be used to predict acceleration of corrosion activity (e.g., when chloride ions are present) or inhibition of corrosion activity.
- (c) Solids. Solids should be sampled whenever they are found inside the pipe. Bacteria cultures (see 4.8 below) and pH need to be taken immediately upon exposing the solids, because the values may change when exposed to air. A typical solid analysis includes the following.
 - (1) *Iron sulfide (FeS₂).* Iron sulfide is a byproduct of the reaction of H₂S and steel, and is also produced by sulfate reducing bacteria. It may be identified as the mineral pyrite or marcasite. Iron sulfide often coats the internal surface of pipe, but because iron sulfide is cathodic to steel, breaks in the scale may often cause acceleration of pitting.
 - (2) *Mineral scale.* Mineral scale may contain a variety of components and compounds, depending on the contaminants and environment. Scale should be examined to determine actual composition, which may suggest corrosion mechanisms. Mineral scale might include salt, calcium and other carbonates, sulfide minerals, as well as a variety of iron minerals. Iron found in a solid sample that has accumulated in vessels, loosened during cleaning pig runs, or debris found when a cutout is made on the line typically represents corrosion product. When evaluating for iron, manganese should also be evaluated.
 - (3) *Erosive material.* Material and other debris, such as sand, quartz, and black powder, might be present in pipeline solids and may create erosion corrosion issues.

4.8 Bacteria culture tests.

Liquids and solids collected should be tested for the presence of both acid-producing bacteria (APB) and sulfate-reducing bacteria (SRB) through the use of culture tests. The presence of bacteria in the system does not necessarily indicate that MIC is occurring. However, further investigation needs to be performed.

4.9 Internal probes or coupons.

Internal probes or corrosion coupons may be used to indicate the presence of internal corrosion. These weight loss devices provide an indication of the corrosion rate in mils per year.

4.10 Operating parameters.

Operating parameters include the following.

- (a) Temperature. The temperature of the gas or liquid present in the pipeline will affect the corrosion rate. In general, each 18 °F temperature increase will double reaction rates. The temperature of both the gas and liquid phases are important. In addition, locations that cool the gas (e.g., crossings of streams, rivers, and swamps) or changes in flow or pressure may cause a condensation of liquids.
- (b) Flow rates. Low flow rates may not effectively sweep the pipeline of liquids or other debris. Flow

rates should be considered where there are changes in pipe diameters, low spots, or other potential liquid collection locations along the pipeline.

- (c) Flow direction. Bidirectional flow or flow reversal may impact the location and the rate of internal corrosion.
- (d) Changes in source of natural gas. Source and location changes of natural gas entering a transmission line might change the composition of the gas stream.
- (e) Pressure. The operating pressure is used to calculate partial pressures for the constituents. The partial pressure of a constituent determined in 4.7 is dependent on the amount of the constituent and the operating pressure of the pipeline. The partial pressure of a gas is calculated by multiplying the mole fraction of the component by the pipeline pressure converted to absolute pressure (psia).

For example, if the mole fraction of CO₂ is 1.2% and the operating pressure of the pipeline is 200 psig (214.7 psia), the partial pressure is $0.012 \times 214.7 \text{ psia} = 2.6 \text{ psia}$, and CO₂ is not likely to cause corrosion. If the operating pressure is 2000 psig (2014.7 psia), the same CO₂ percent would yield a partial pressure of 24.2 psia ($0.012 \times 2014.7 \text{ psia} = 24.2 \text{ psia}$), which is more likely to cause internal corrosion.

4.11 Operating stress level.

Operating stress level is a key factor in predicting failure mechanisms and determining the tolerance to internal corrosion. Flow reversals might change the pressure gradient of a pipeline by affecting the operating stress level at different points along the pipeline. The effect of new pressure gradient on existing defects should be evaluated.

4.12 Other considerations.

In addition to the data elements listed in ASME B31.8S, Appendix A2, the following data may be useful in evaluating corrosion.

- (a) The factors listed in guide material under §192.476 regarding internal corrosion include the following.
 - (1) Liquid removal facilities, such as drips, siphons, or dehydrators.
 - (i) Type of liquid removal facility and locations.
 - (ii) The quantity of liquids removed from the facility.
 - (iii) The frequency of liquid removal.
 - (2) Pipeline profile and configuration (e.g., low spots, dead legs, other locations where liquid could collect).
- (b) Critical angle analysis can be used to evaluate internal corrosion as a threat. See 5 of the guide material under §192.927.
- (c) History of upset conditions which could have introduced corrosive constituents into the gas stream.
- (d) Chemical treatments (e.g., corrosion inhibitors, biocides), including the types of chemicals used for treatment, frequency of treatment, and how the treatment was administered (e.g., continuous or batch).
- (e) The presence and condition of internal coatings.
- (f) Pigging and other cleaning history.
- (g) Incident and safety-related condition reports related to internal corrosion.

5 STRESS CORROSION CRACKING

- (a) In evaluating the threat of stress corrosion cracking (SCC), ASME B31.8S, Appendix A3 provides a list of data that the operator is required to gather and evaluate. Additional information can also be found in guide material under §192.613, and the reference listed in 16.1.7 below. Pipeline segments may be susceptible to two types of SCC; high pH and near-neutral pH.
- (b) SCC requires three conditions to be satisfied simultaneously:
 - (1) a tensile stress above the threshold stress,

- (2) an appropriate environment at the steel surface, and
- (3) a susceptible material.
- (c) In accordance with ASME B31.8S, Appendix A3.3, the operator must consider the threat of high pH SCC if all of the following operating conditions apply to the pipeline.
 - (1) Segment is less than 20 miles downstream of a compressor.
 - (2) Operates above 60% SMYS.
 - (3) Is not coated with fusion bonded epoxy (FBE).
 - (4) Operating temperatures historically above 100 °F.
 - (5) Has been in service more than 10 years.
- (d) Operators with historical SCC failures in locations that are outside of the above screening criteria should adjust their screening criteria to reflect operating history when performing threat identification, risk analysis, and assessment plans.
- (e) ASME B31.8S, Appendix A3.3 also requires that each segment that has experienced a failure, leak, or hydrostatic test break caused by SCC must be evaluated, unless the conditions that led to SCC have been corrected (e.g., coating replaced with FBE).
- (f) SCC is primarily a result of exposure of the pipe to specific soil conditions. Pipeline coatings help protect the pipe, but the coating can be damaged by high temperatures. High temperatures are primarily associated with proximity to a compressor. Pipelines with coal tar, asphalt, and tape coatings that have been exposed to higher temperatures for prolonged periods of time have an increased potential for SCC. Key factors in the determination of the SCC threat are the coating, the pipe materials, and the conditions under which the pipeline is operated.

5.1 *Age of pipe.*

Since SCC threat is time-dependent, the threat may increase the longer the pipe is in service provided all of the operating conditions required to support SCC have been met. ASME B31.8S, Appendix A3 states that a segment does not need to be assessed for SCC if the age of the pipe is less than 10 years.

5.2 *Operating stress level (percent SMYS).*

A pipeline operating above 60% SMYS might be susceptible to high pH SCC. Increases in steel toughness, which have generally occurred in parallel with increasing SMYS, have significantly increased the size of cracks that a pipeline can tolerate without failing. With improved manufacturing procedures, higher-strength grades of line pipe are available for which the combination of diameter and MAOP, or maximum actual operating pressure (MOP), may minimize the effects of SCC. See 16.1.8 below.

5.3 *Operating temperature.*

Higher pipeline temperatures can increase the probability of SCC. ASME B31.8S, Appendix A3 states that high pH SCC needs to be assessed only if the pipeline temperature is greater than 100 °F. Higher pipeline temperature may be due to compressor discharge, gas from deep wells with higher down-hole temperatures, and long-term underground fires. Temperature may accelerate high pH SCC. However, "near-neutral pH" SCC can occur at temperatures less than 100 °F. Elevated temperatures can also contribute to coating disbondment and deterioration. Both current and historical temperature records need to be examined.

5.4 *Distance of the segment from a compressor station.*

A pipeline segment less than 20 miles downstream of a compressor station may be more susceptible to high pH SCC because of high discharge temperatures. The potential for SCC should be considered when modifying existing suction and discharge piping of a compressor station for flow reversal.

5.5 *Coating type.*

- (a) SCC has not been found on pipe with undamaged FBE or extruded polyethylene coating. High pH SCC has been found under disbonded coal tar, asphalt, and tape coatings. Near-neutral pH SCC is most commonly associated with tape coatings, but has also been found under asphalt coatings. It has been reported that about three-quarters of near-neutral pH SCC-related

occurrences are associated with these tape coatings. See 16.1.8 below.

- (b) Additionally, the age of the pipe may impact the coating degradation, and increase susceptibility to SCC. Surface preparation for the coating is an important factor to consider for both near-neutral and high pH SCC. Shot peening or grit blasting appear to be beneficial by removing mill scale, inhibiting crack initiation, and creating compressive residual stresses in the surface of the pipe. Mill scale tends to promote potential for high pH SCC.
- (c) During investigation of coating anomalies, pipe inspection for cracks should be considered since SCC has been observed on bare pipelines in high resistance soils.

5.6 *History of SCC.*

There is a high probability of finding additional SCC in areas where it has previously been found. An operator may have a unique factor such as pipe manufacturer or age of the pipe that is also important in the determination of the potential severity and location of the threat.

5.7 *Other considerations.*

- (a) Soil types. Particularly high resistance soils might be correlated with near-neutral pH SCC. See 16.1.7 below.
- (b) Cathodic protection (CP). Areas with low CP readings (<850 mV as referenced to a copper-copper sulfate half cell) tend to be more prone to high pH SCC. High CP readings might lead to possible disbondment of the coating which might lead to more susceptibility of near-neutral pH SCC. Potentials >1200 mV (compensated for IR drop) might need to be investigated.
- (c) Seam type. Near-neutral pH SCC has been found in the heat-affected zone of the longitudinal seams of some pre-1970 ERW pipe. Near-neutral pH SCC has also been found under tented (never bonded) tape coatings over double submerged arc (DSA) welds. See NACE RP0204-2004, Section 3.2, Table 1.
- (d) Pipe attributes. There is no known correlation of SCC to grade, diameter, and wall thickness of the pipe.
- (e) Cyclic fatigue. A pipeline that is exposed to cyclic pressure fluctuations might experience cyclic softening. Cyclic softening is a phenomenon in which the application of stress cycles close to maximum stress levels (below the yield stress) manifests itself as a loss of yield strength. The operator has little control over the metallurgical susceptibility to cyclic softening but can, in some instances, monitor the magnitude and frequency of pressure cycles on a pipeline. See 16.1.8 below.

6 **MANUFACTURING THREATS**

- (a) This threat refers to defects of the pipe seam or pipe body that are associated with the manufacturing process.
- (b) Some examples of manufacturing defects include the following.
 - (1) Seam defects.
 - (i) Low quality seams associated with early manufacturing processes, including flash-welded seams and very early ERW processes (e.g., pre-1970 ERW pipe).
 - (ii) Incomplete fusion (incomplete coalescence of portions of the metal in a weld joint).
 - (iii) Hook cracks (upturned fiber imperfections caused by imperfections at the edge of the skelp).
 - (2) Blisters (raised spots on the surface of the pipe that result from the expansion of gas in cavities of the pipe wall).
 - (3) Ovality (oval or egg-shaped pipe).
 - (4) Laminations (internal metal separation creating layers parallel to the pipe surface).
 - (5) Inclusions (impurities within the pipe wall).
 - (6) Burnt pipe (a sporadic lap-welded pipe problem that occurs when the edges of the skelp are overheated and austenite grain-boundary sulfides form, making the pipe brittle and susceptible to cracks).
 - (7) Hard spots (high-hardness areas in the pipe caused by localized quenching during hot

- rolling of the skelp).
- (8) Inconsistent pipe wall thickness variations outside of tolerance.
- (9) Substandard yield strength.
- (c) In evaluating manufacturing threats, ASME B31.8S, Appendix A4 provides a list of data the operator is required to gather and evaluate as outlined below.

6.1 *Pipe material.*

Impurities in the steel can lead to laminations and inclusions.

6.2 *Year of installation.*

- (a) Manufacturing processes have changed over time.
- (b) Certain types of defects can be associated with different years of manufacturing.

6.3 *Manufacturing process.*

- (a) Seamless.
- (b) Welded.
- (c) Specification to which it was manufactured.
- (d) Pipe with actual yield strength below specified minimum yield strength. See 16.1.9 and 16.1.13 below.

6.4 *Seam type.*

- (a) The operator should have data regarding the seam type of the pipe in its system. Based on individual data and year of manufacture, seam type might influence threat analysis.
- (b) Seam types that may have a higher risk include the following.
 - (1) Bell weld.
 - (2) Continuous weld.
 - (3) Submerged-arc weld.
 - (4) Electric-flash weld.
 - (5) Electric-fusion weld.
 - (6) Low-frequency electric-resistance weld.
 - (7) Furnace-butt weld.
 - (8) Furnace-lap weld.
 - (9) Butt weld.
 - (10) Tack weld.
- (c) Seam types that may have a lower risk.
 - (1) Double submerged-arc weld.
 - (2) Seamless.
 - (3) Spiral weld.
 - (4) High-frequency electric-resistance weld.
- (d) Section 192.917(e)(4) specifically addresses pipelines that are made by the low-frequency ERW manufacturing process because of historical incidents. This type of manufactured pipe is susceptible to selective seam corrosion. If the operator has a known history of seam failures, this manufacturing threat must be considered to exist. See 16.1.11, 16.1.12, and 16.1.13 below.
- (e) The operator could identify seam or pipe defects during normal operation and maintenance activities, such as leak repairs, failure analyses, and prior assessment results.

6.5 *Joint factor.*

ASME B31.8S, Appendix A4.3 requires that if pipe has a joint factor of less than 1.0 (see table in §192.113), then a manufacturing threat is considered to exist.

6.6 *Operating pressure history.*

For the covered segments, the operator must collect pressure history for at least the past five years to document at which pressure the defects are considered stable (see §192.917(e)(3)). Also, see 12.3(b)(4) below. Manufacturing and construction defects are considered to be stable defects if the operating conditions did not significantly change in the five years prior to the identification of the HCA.

Operation of a pipeline without failures demonstrates that the manufacturing defects are stable and have not been a threat to pipeline integrity. Changes in operating conditions, such as a significant increase in pressure, could cause latent defects to grow. For changes in pipeline operating conditions, where operating pressure will be above the historic operating pressure or if stresses that could lead to cyclic fatigue increase, the operator must assign a high priority to assessing the manufacturing threat (§192.917(e)(2) and (3)).

6.7 *Other considerations.*

Manufacturing threats may be magnified due to local environmental conditions. An operator is required to examine the terrain and right-of-way for subsidence, landslides, washouts, frost heaving, or other lack of support if any of the following conditions exists (§192.917(e)(4)).

- (a) Pipe is more than 50 years old.
- (b) Pipeline is mechanically coupled.
- (c) Pipeline is joined by oxyacetylene girth welds.

Indications are that a successful hydrotest at 1.25 times the MOP might prove the stability of manufacturing defects. See 16.1.14 below.

7 CONSTRUCTION THREATS

Construction threats are related to the fabrication process used in the construction of a facility. Construction threats include the following.

- (a) Pipe girth welds.
- (b) Fabrication welds.
- (c) Wrinkle bends or buckles.
- (d) Miter joints.
- (e) Threaded connections.
- (f) Couplings.
- (g) Arc burns.
- (h) Dents formed during installation or pressure testing.
- (i) Mechanical damage (e.g., gouges, chain marks).

In evaluating construction threats, ASME B31.8S, Appendix A5 provides a list of data that the operator is required to gather and evaluate.

7.1 *Pipe material.*

Verify that pipe meets criteria for design MAOP and welding procedures match the pipe specification.

7.2 *Wrinkle bend identification.*

Review construction and repair records for location of wrinkle bends. If an operator suspects wrinkle bends in the line, the operator should consider running a caliper tool. Wrinkle bends can indicate a weak spot or a stress riser.

7.3 *Coupling identification and reinforcement.*

Review construction and repair records for location of mechanical couplings or reinforcement fittings (e.g., canopy, pumpkin, sleeve, strap).

7.4 *Welding procedures.*

Review construction and repair records for welding process, procedures, and industry standards used (e.g., submerged arc, oxyacetylene, API Std 1104, ASME Section IX).

7.5 *Welding inspection (including NDT information).*

Review construction and repair records for type, percent inspected, and repair rates. See guide material under §192.241.

7.6 *Post-construction girth weld reinforcement.*

Review construction and repair records for locations and type.

7.7 *Hydrostatic test information.*

Operators should have procedures in place to ensure that high test pressures (above 100% SMYS) do not result in excessively expanded pipe. If excessive test pressures cannot be avoided due to pipeline profile, the operator should have a method of evaluating the condition of the pipeline (e.g., caliper pig) after the hydrostatic test. Expanded pipe may result in cracked coating.

7.8 *Pipe inspection reports (Bell hole).*

Review repair and inspection records for anomalous conditions found on the pipeline when exposed.

7.9 *Potential for outside forces.*

Review construction and repair records for soil type, fault zones, unstable slopes, weather events, depth of frost line, proper support, or padding. See 11 below for weather-related threats.

7.10 *Soil properties.*

Review construction records, repair records, and pipe inspection reports for soil type. Operator may consider the soil type and its effect on settlement, CP, and stress loading on the pipeline. The operator may also want to consider the type of fill material used in burial of the pipe, as well as indications that padding, shoring, or abrasion protection material (e.g., rock shield) was used.

7.11 *Maximum temperature range for wrinkle bends.*

Review construction and repair records. Operator may consider the effect of high and low temperatures on coating, material fatigue, SCC promotion, and brittle fracture. Thermal expansion and contraction could fatigue wrinkle bends.

7.12 *Bend radii and angle for wrinkle bends.*

Review construction and repair records for locations and design parameters of wrinkle bends. See 16.1.15 below.

7.13 *Operating pressure history and expected operation including significant pressure cycling and fatigue mechanisms.*

Review operating records for history of significant pressure cycling or pressure increases over a historic MOP before HCA identification for the consideration of the construction threat.

7.14 *Other considerations.*

In addition to the data elements listed in ASME B31.8S, Appendix A5, the following data may be useful in evaluating for construction threats.

- (a) Results of prior assessments.
- (b) Past incidents, leakage information, safety-related condition reports, and abnormal operations for evidence of past construction issues.
- (c) Installation techniques (e.g., bored, open trenched, depth of cover).
- (d) Cased pipe (e.g., filled or unfilled, with or without spacers, seals, or vents).
- (e) Trench conditions (rock versus soil), fill material.
- (f) Pipe supports or river weights.
- (g) Thermal expansion and contraction.
- (h) Temperature effect of on coating, material fatigue, SCC promotion and brittle fracture.
- (i) Use of abrasion protection material.
- (j) Aerial crossings.
- (k) Aboveground facilities.
- (l) Field-applied coatings.
- (m) Locations and design parameters of miter bends.

Construction defects are much more susceptible to longitudinal stresses than to hoop stresses. See 16.1.14 below.

8 EQUIPMENT THREATS

Equipment can be defined as pipeline facilities other than pipe and pipe fittings and includes the following.

- (a) Valves.
- (b) Pressure control and regulation equipment.
- (c) Relief and overpressure protection equipment.
- (d) Gaskets, seals, packings, and O-rings.
- (e) Measurement and instrumentation equipment.
- (f) Controls.
- (g) Corrosion control equipment.

In evaluating equipment threats, ASME B31.8S, Appendix A6 provides a list of data that the operator is required to gather and evaluate.

8.1 *Year of installation of failed equipment.*

- (a) Specifications, standards, and codes in effect at the time of manufacture.
- (b) Amount of in-service versus idle time.

8.2 *Regulator and relief valve failure information*

Leakage and failure history may be available from sources such as the following.

- (a) Operator generated data.
 - (1) Site specific (e.g., location, MAOP, MOP).
 - (2) Operating conditions.
 - (3) Changing maintenance programs.
 - (4) Information regarding past failures can be found in incident reports, safety-related condition reports, leakage information, abnormal operation investigations, and other failure investigations required by §192.617.
- (b) Industry generated data.
 - (1) Known predispositions (e.g., certain gaskets may be prone to premature degradation).
 - (2) Trends.
- (c) OPS advisory bulletins and alert notices.
- (d) NTSB accident report recommendations.

8.3 *Flange gasket and O-ring failure information.*

- (a) Recurring problems with similar items should be reviewed. Information regarding past failures can be found in incident reports, safety-related condition reports, leakage information, abnormal operation investigations, and other failure investigations required by §192.617.
- (b) Gasket material (e.g., stainless steel, elastomer, composite, paper).
- (c) Age of gasket.
- (d) Compatibility with odorants, methanol, or other additives.

8.4 *Regulator and relief valve set-point drift.*

The term "set-point drift" is not defined in any standards or manufacturing literature for regulators and relief valves. It appears that the term "set-point drift," as used in ASME B31.8S, was intended to draw attention to "repeatability" of the equipment. Repeatability may be indicated by how often the device needs to be adjusted. Adjustment information may be found in annual or other inspection information.

8.5 *Seal/packing information (e.g., lubrication, sealant injection, frequency).*

Recurring problems with similar items should be reviewed. Maintenance reports and work management

systems may provide information.

8.6 *Other considerations.*

- (a) Manufacturer information (e.g., make, model, recalls, alerts).
- (b) Manufacturer recommended installation procedures.
- (c) Maintenance history (e.g., meeting or exceeding manufacturer's recommendations, set-point drifts).
- (d) Potential for debris build-up in equipment (e.g., pipeline construction activities upstream of equipment, use of cleaning pigs).

9 **THIRD-PARTY DAMAGE**

In the context of Subpart O, third-party damage includes the following.

- (a) Excavation damage that results in the need to assess, repair, or replace an underground pipeline facility due to a weakening condition, partial destruction, or complete destruction from any earth-moving activity near the pipeline carried out by the operator, the operator's contractor, or a third party (generally referred to as first, second, or third party, respectively).
- (b) Vandalism.
- (c) Vehicular damage.

In evaluating the threat of third-party damage, ASME B31.8S, Appendix A7 provides a list of data that the operator is required to gather and evaluate. All facilities are subject to the threat of third-party damage.

9.1 *Vandalism incidents.*

Vandalism incidents may affect pipe, coating, CP, operating controls or settings. Factors to consider in identifying the threat of vandalism may include the following.

- (a) Frequency.
- (b) Severity or type (e.g., paint, pipe bombs, firecrackers, target practice, arson, accidental, intentional).
- (c) Aboveground valves or other devices.
- (d) Defaced, damaged, or removed pipeline markers.
- (e) Security measures.

9.2 *Pipe inspection reports.*

See guide material under §§192.459 and 192.935(b).

9.3 *Leak reports resulting from immediate damage.*

- (a) Type of damage (e.g., excavation, vehicle damage, vandalism).
- (b) Location.
- (c) Frequency.
- (d) One-call records.
- (e) Reportable or non-reportable incident.

9.4 *Incidents (events) involving previous damage.*

- (a) Type of damage (e.g., excavation, vehicle damage, vandalism).
- (b) Location.
- (c) Frequency.
- (d) One-call records.

9.5 *In-line inspection.*

- (a) Section 192.933 requires remediation of certain dents that might indicate excavation damage to top of the pipe between the 8 o'clock and 4 o'clock positions.
- (b) Direct assessment reports may provide additional information.

9.6 *One-call records.*

- (a) Frequency of excavation activity near pipeline (operator to use judgment of "nearness").
- (b) Identity of excavator, particularly excavators with known histories of damage.
- (c) Effectiveness of one-call program. See 16.3.1 below.

9.7 *Encroachment records.*

Encroachment can include foreign line crossings. Factors to consider include the following.

- (a) Proximity to pipeline as indicated from patrols and surveys.
- (b) Indications of digging where unreported damage could have occurred.
- (c) History of excavation damage.
- (d) Proposed construction drawings.

9.8 *Other considerations.*

- (a) Other activities such as logging, deep tilling, land leveling, or heavy equipment crossings.
- (b) Blasting analyses, external loading evaluations, or other activities that actually calculate the stresses on the pipe.
- (c) Depth of cover.
- (d) Abnormal operations, safety-related conditions, security threats, or alarms.

10 **INCORRECT OPERATIONS (HUMAN ERROR)**

This threat is time-independent and may occur at any time. Incorrect operations include the following.

- (a) Failure to follow correct operating procedures.
- (b) Following incorrect, outdated, or incomplete operating procedures.
- (c) Unqualified person performing an unfamiliar task.
- (d) Use of uncalibrated or unauthorized tools.

In evaluating the threat of incorrect operations, ASME B31.8S, Appendix A8 provides a list of data that the operator is required to gather and evaluate. All facilities are subject to the threat of incorrect operations.

10.1 *Procedure review information.*

The procedure review for completeness and effectiveness should include the following.

- (a) Procedural manual for operations, maintenance, and emergencies.
- (b) Damage prevention program.
- (c) Operator qualification program.
- (d) Anti-drug and alcohol program.
- (e) Safety manual.
- (f) IMP periodic evaluations.
- (g) Adherence to operator procedures.
- (h) Operator procedures for conducting post-incident, abnormal operations, and failure investigations.

10.2 *Audit information.*

The results of both internal and external audits should be reviewed. Internal audits might include self audits in the following areas.

- (a) Field operations.
 - (1) Valve inspections and maintenance.
 - (2) Leak surveys.
 - (3) Cathodic protection.
 - (4) Patrolling.
 - (5) Overpressure protection and other safety devices.
- (b) Construction activities.
- (c) Office operations (e.g., documentation, processes).
- (d) Mapping.

10.3 *Failures caused by incorrect operations.*

Failures or potential failures caused by an incorrect operation may be found in the following reports.

- (a) Abnormal operations.
- (b) Safety-related conditions.
- (c) Root-cause analysis.
- (d) Incidents.
- (e) Near misses.
- (f) OQ disqualifications.

11 WEATHER AND OUTSIDE FORCES

Weather-related and outside force threats have the capability to create extreme loading conditions on pipelines. In assessing this type of threat, ASME B31.8S, Appendix A9 provides a list of data that the operator is required to gather and evaluate to determine whether pipelines are being subjected to extreme loading conditions caused by weather or outside forces. Aboveground facilities are also prone to weather-related events.

11.1 *Pipe joining method.*

Pipelines with the following joint types are more susceptible to leakage or failure from the threat of weather-related and outside forces than pipelines constructed using modern joining methods.

- (a) Mechanical fittings that do not have restraints to prevent pipe pull-out.
- (b) Oxyacetylene welds, due to their brittleness.
- (c) Miter joints.

11.2 *Topography, soil conditions, and frost depth.*

The following topographical areas should be examined to determine if they contribute to this threat by exerting extreme loading conditions (e.g., bending, tension, compression).

- (a) Slopes prone to movement or other unstable areas that would induce additional stress in a pipeline due to the movement of soil.
- (b) Extremely saturated soils that produce buoyant forces on pipelines.
 - (1) River and stream crossings.
 - (2) Lowlands, floodplains, and swamps.
 - (3) Coastal areas prone to tidal surges from hurricanes or tropical storms.
- (c) Areas susceptible to frost heave.
- (d) Highly expansive or unstable soils (e.g., some clays or manmade soils).
- (e) Locations with known geologic conditions that contribute to instability (e.g., karst topography, sinkholes, underground mining, other subsidence areas).

11.3 *Fault zones.*

The following should be considered in evaluating an active or known fault zone.

- (a) Location of earthquake fault lines.
- (b) Previous earthquake activity.
- (c) Probability of future earthquake activity along fault.
- (d) Analyses of leaks or damage attributable to earthquake activity.

11.4 *Year of installation.*

Older pipeline facilities were constructed with materials and techniques that are generally not equivalent to modern facilities in terms of strength and integrity. The risk attributable to weather-related and outside force threats may be commensurate with the age of the pipeline facilities. If the installation data is not known, conservative estimates of the installation year can be used.

11.5 *Pipe parameters.*

The following pipe parameters are factors in determining operating hoop stress

- (a) Pipe grade.
- (b) Wall thickness.
- (c) Outside pipe diameter.

ASME B31.8S, Appendix A9.2(g) states that the sum of all pipe stresses (e.g., longitudinal, hoop stress, bending, overburden) is not to exceed 100% SMYS. If any of the pipe parameters are not known, conservative estimates of the missing data should be used.

11.6 *Other considerations.*

- (a) Weather-related conditions.
Excessive loading from weather-related conditions that are likely to occur (see guide material under §§192.317 and 192.615).
 - (1) Tornado activity or high winds.
 - (2) Heavy snow or ice loading.
 - (3) Lightning strikes.
 - (4) Wild (or other) fires.
 - (5) Flooding (see 6 of guide material under §192.613).
- (b) Operations and maintenance records.
Operators should review operations and maintenance records (e.g., patrolling data) to determine whether extreme loading conditions are present on their pipelines. Information may also be found in incident reports, safety-related condition reports, leakage information, abnormal operations, and other failure investigations required by §192.617.
- (c) Fatigue cracking from improper loading of pipe on railcars.
- (d) See 16.3.2 below.

12 PLASTIC TRANSMISSION PIPELINES

12.1 General.

The following guide material is generally repetitive of Sections 6 through 11 above. The portions of those sections that are also applicable to plastic pipelines have been consolidated here for the convenience of operators with plastic transmission pipelines.

For additional guidance on identifying threats to plastic pipelines, see Guide Material Appendix G-192-8, Section 4. Although that appendix is directed at distribution facilities, the threat identification process may be applied to plastic transmission pipelines.

12.2 *Identification of threats to plastic pipelines.*

Section 192.917 requires operators to address all potential threats to pipeline integrity. Threats for plastic pipelines may be grouped into the following categories.

- (a) Time-dependent threats.
Time-dependent threats are those that may grow more severe over time. Analysis based on sound engineering practices may be used to help predict when these threats might become critical. For plastic pipelines, these threats include the following.
 - (1) Crack propagation.
 - (2) Degradation due to exposure to liquid hydrocarbons.
- (b) Stable threats.
A threat that has passed post-construction testing may be considered stable. However, stable threats may need to be reconsidered as external factors (e.g., external loading, temperature changes, pressure changes) act upon the pipeline. Stable threats include the following.
 - (1) Manufacturing defects.
 - (2) Construction defects.
 - (3) Equipment failures.
- (c) Time-independent threats.
Time-independent threats are generally associated with events that may take place along the pipeline segment and can happen at any time. These threats include the following.

- (1) Excavation damage.
- (2) Incorrect operations (includes human error).
- (3) Weather-related and outside force.
- (d) Other threats.

Section 192.917 also requires operators to analyze the pipeline for other threats that may not fit into one of the above categories. See 12.9 below.

12.3 Manufacturing threats.

This threat refers to defects of the pipe or fittings that are associated with the manufacturing process. Additional guidance for manufacturing considerations related to plastic pipelines can be found in guide material under §§192.121, 192.123 and 192.613 and OPS Advisory Bulletins (ADB). See 16.2 below for a list of applicable ADBs.

(a) Potential manufacturing threats.

- (1) Identification of a manufacturing defect may be accomplished as follows.
 - (i) By observations of pipe surfaces and fittings during normal construction, operation, and maintenance activities.
 - (ii) Through failure analysis, such as after incidents.
 - (iii) During review of prior integrity assessment results.
 - (iv) By review of Plastic Pipe Database Committee (PPDC) reports. See 16.2.2 below.
- (2) Some examples of pipe defects include the following.
 - (i) Errors or upsets in material resin formulation.
 - (ii) Wall thinning or scoring.
 - (iii) Fiberglass reinforced plastic (FRP) delamination.
 - (iv) Inclusions (e.g., impurities within the pipe wall).
 - (v) Ovality (oval or egg-shaped pipe).
 - (vi) Laminations (internal separation in pipe wall creating layers parallel to the pipe surface).
 - (vii) Insufficient amount of ultraviolet light stabilizers.
 - (viii) Pipe diameter and wall thickness variations outside of tolerance.
- (3) Fittings (including metallic fittings) used to join plastic pipe. Defects may involve the following.
 - (i) Improper gaskets (type, size, shape, thickness, composition).
 - (ii) Poorly sized stiffeners.
 - (iii) Inclusions.
 - (iv) Missing or deformed pull-out resistant device.
 - (v) Inconsistent pipe wall thickness variations outside of tolerance.
 - (vi) Cracks.
 - (vii) Blow-holes.
- (4) Stability of threat.

The operator could consider the manufacturing threat to be stable if the operating pressure has not increased over the maximum operating pressure experienced during at least five years preceding identification of the HCA. If any of the following changes occur in the covered segment, the operator should consider prioritizing the covered segment as a high-risk segment for the baseline assessment or a subsequent reassessment.

 - (i) An overpressurization event.
 - (ii) Increase of MAOP by pressure test or uprating.
 - (iii) Increase in the stresses leading to cyclic fatigue. See discussion of cyclic fatigue in guide material under §192.613.

(b) Data collection.

ASME B31.8S, Appendix A4 relates to metallic pipelines, but may be useful as a format for data that should be collected to evaluate a plastic pipeline for manufacturing threats. The following list may be applicable to plastic pipelines and should be considered by the operator.

- (1) Pipe material.
 - (i) Acrylonitrile butadiene styrene (ABS).
 - (ii) Cellulose acetate butyrate (CAB).
 - (iii) Fiberglass reinforced plastic (FRP). See 16.2.4 below for a reference providing specifications on fiberglass pipe.
 - (iv) Polyamide (PA).
 - (v) Polyethylene (PE).
 - (vi) Polyvinyl chloride (PVC).
 - (vii) Other.
- (2) Year of installation.

Some older plastic pipe materials are susceptible to premature brittle-like cracking (see guide material under §192.613). If pipe material is unknown, the year of installation may provide some indication that more susceptible material might have been installed. See 16.2.1 below. Specific manufacturing years may be of concern for the following materials.

 - (i) Century Utilities Products, Inc. pipe.
 - (ii) Low-ductile inner wall PE 2306 "Aldyl-A".
 - (iii) PE 3306.
 - (iv) PVC.
 - (v) CAB.
 - (vi) Driscopipe 8000.
- (3) Manufacturing process.
 - (i) Examples of pipe manufacturing processes include the following.
 - (A) Extrusion.
 - (B) Filament-wound thermosetting epoxies (e.g., FRP).
 - (ii) Examples of fitting manufacturing processes include the following.
 - (A) Injection molded.
 - (B) Machined.
 - (C) Combinations of the above processes including use of the various fusion methods.
- (4) Operating pressure history.

For the covered segments, the operator should collect pressure history for at least the past five years.

12.4 Construction threats.

For additional installation considerations, see guide material under §192.321.

- (a) Potential construction threats.

Construction threats are related to the methods used in the construction and installation of a pipeline and include the following.

 - (1) Joint fusions.
 - (i) Incomplete fusions.
 - (ii) Issues regarding cold fusion. This type of fusion is associated with and without the use of mechanically assisted fusion tools.
 - (iii) Ovality and alignment of coiled pipe may affect proper joining.
 - (2) Joining pipe or fittings by mechanical coupling.
 - (i) Type of coupling.
 - (ii) Installation error.
 - (iii) Pull-out potential (expansion and contraction).
 - (3) Installation methods.
 - (i) Direct burial with or without select padding material.
 - (ii) Plowed in.
 - (iii) Horizontal directional drilled.
 - (iv) Inserted in an existing pipeline as a pipeline replacement.

- (v) Inserted in an existing or new buried casing.
- (vi) Inserted in aboveground casing (bridge crossing).
- (vii) Proximity to other underground structures.
- (viii) Inadequate spacing between tracer wire and pipe.
- (4) Ability to locate.
 - (i) Installation of tracer wire, warning tape, marker balls, or marker discs.
 - (ii) Electrical continuity of locate wire.
 - (iii) Proximity of locate wire to pipe.
 - (iv) Locatable warning tape.
 - (v) Accuracy of as-built dimensions.
- (5) Exposure to elevated temperature (e.g., warmer climates, hot asphalt, proximity to electric or steam lines).
- (6) Inadequate or excessive depth of cover.
- (b) Data collection.

ASME B31.8S, Appendix A5 generally relates to metallic pipelines, but may be useful as a format for data that should be collected to evaluate a plastic pipeline for construction threats. Of the specific data sets in ASME B31.8S, Appendix A5, the following list may be applicable to plastic pipelines and should be considered by the operator.

 - (1) Pipe material.

Verify that pipe is made to specifications and meets criteria for design MAOP.
 - (2) Coupling and fitting identification .

Review construction and repair records for location and type of mechanical couplings and other fittings.
 - (3) Joining procedures.

Review joining procedures and industry standards used to ensure procedures match the pipe (e.g., butt fusion, sidewall fusion, electrofusion, fusion of different materials). See guide material under §§192.283 and 192.285.
 - (4) Joining inspection.

Review construction and repair records for type, percent inspected, and repair/replacement rates.
 - (5) Pressure test information.

Evaluate whether pressure tests performed in the field could have damaged the pipe (e.g., expanded, weakened).
 - (6) Pipe inspection reports.

Review repair and inspection records for anomalous conditions found on the pipeline.
 - (7) Potential for outside forces.

For weather-related and outside force threats, see 12.8 below.
 - (8) Soil properties.

Review construction records, repair records, and available pipe inspection reports for soil, padding and backfill types. Operator may consider the soil type and its effect on settlement, expansion, and stress loading on the pipeline. Chemicals present in the soil or backfill may be deleterious to the plastic material.
 - (9) Maximum temperature range.

Review construction and repair records. Significant temperature extremes while under construction could have produced thermal expansion and contraction stresses in the pipeline.
 - (10) Bend radii.

Review construction and repair records for locations of pipeline deflection without the use of fittings. Compare these values to the manufacturer's recommendations.
 - (11) Operating pressure history.

Review operating records for history of pressure changes for at least five years preceding identification of the HCA.

12.5 Equipment threats.

Equipment can be defined as pipeline facilities other than pipe and pipe fittings.

(a) For plastic pipelines, equipment-related threats may include failure of the following.

- (1) Valves.
- (2) Gaskets, seals, packings, and O-rings.
- (3) Pressure control and overpressure protection devices.
- (4) Mechanical joining devices.
- (5) Measurement and instrumentation equipment.

(b) Data collection.

ASME B31.8S, Appendix A6 relates to metallic pipelines, but may be useful as a format for data that should be collected to evaluate a plastic pipeline for equipment threats. The following list may be applicable to plastic pipelines and should be considered by the operator.

- (1) Manufacturer information (e.g., make, model, recalls, alerts)
- (2) Maintenance history (e.g., maintenance exceeds manufacturer's recommendations, set-point drifts (see 12.5(b)(5) below)).
- (3) Year of installation of failed equipment.
 - (i) Specifications, standards, and codes in effect at the time of manufacture.
 - (ii) Amount of in-service versus idle time.
- (4) Leakage and failure history.

Information regarding past failures can be found in incident reports, safety-related condition reports, leakage information, abnormal operation investigations, and other failure investigations required by §192.617, which may include the following.

 - (i) Operator generated data.
 - (A) Site specific (e.g., location, MAOP, MOP).
 - (B) Operating conditions.
 - (C) Changing maintenance programs.
 - (ii) Industry generated data.
 - (A) Known predispositions (e.g., certain gaskets may be prone to premature degradation).
 - (B) Trends.
 - (C) Plastic Pipe Database Committee (PPDC) reports.
 - (iii) OPS advisory bulletins and alert notices.
 - (iv) NTSB accident report recommendations.
- (5) Set-point drift.

The term "set-point drift" is not defined in any standards or manufacturing literature for regulators and relief valves. It appears that the term "set-point drift," as used in ASME B31.8S, was intended to draw attention to "repeatability" of the equipment. Repeatability may be indicated by how often the device needs to be adjusted. Adjustment information may be found in annual or other inspection information.
- (6) Seal or packing Information (e.g., lubrication, sealant injection, frequency).

12.6 *Third-party damage.*

(a) Potential third-party damage threats.

In the context of Subpart O, third-party damage includes the following.

- (1) Excavation damage that may result from any earth-moving activity near the pipeline carried out by the operator, the operator's contractor, or an excavator not under the control of the operator (aka first, second, or third party).
- (2) Vandalism.
- (3) Vehicular damage.

(b) Data collection.

ASME B31.8S, Appendix A7 relates to metallic pipelines, but may be useful as a format for data that should be collected to evaluate a plastic pipeline for third-party damage threat. The following list may be applicable to plastic pipelines and should be considered by the operator.

- (1) Vandalism incidents.

Vandalism incidents may affect pipe, locating facilities, operating controls or settings.

Factors to consider for identifying the threat of vandalism may include the following.

- (i) Affect on pipe or ability to locate.
 - (ii) Frequency.
 - (iii) Severity or type (e.g., pipe bombs, arson, accidental, intentional).
 - (iv) Valves or other devices that are not buried or otherwise protected.
 - (v) Defaced, damaged, or removed pipeline markers.
 - (vi) Damaging plastic pipeline on bridges.
 - (vii) Security measures.
- (2) Pipe inspection reports.
If the information is available, it may be useful and could include the following.
- (i) Discovery of non-reported damage.
 - (ii) Shallow pipe.
- (3) Leak reports.
- (i) Type of damage (e.g., excavation, vehicle damage, vandalism).
 - (ii) Location.
 - (iii) Frequency.
 - (iv) One-call records.
 - (v) Reportable or non-reportable incident.
- (4) Incidents (events) involving previous damage.
- (i) Type of damage (e.g., excavation, vehicle damage, vandalism).
 - (ii) Location.
 - (iii) Frequency.
- (5) One-call records.
- (i) Frequency of excavation activity around pipeline.
 - (ii) Identity of excavator.
 - (iii) Effectiveness of one-call program See 16.3.1 below.
- (6) Encroachment records.
- (i) Proximity to pipeline as indicated from patrols and surveys.
 - (ii) Indications of digging where unreported damage could have occurred.
 - (iii) History of excavation damage.
 - (iv) Proposed construction drawings.
 - (v) Damage to locating wires or facilities.
 - (vi) Construction by others of steam or electric facilities close to the plastic pipeline.
- (c) Other considerations.
- (1) Preventive and mitigative measures that have been implemented.
 - (2) Vehicular damage to aboveground facilities with the potential to cause damage to plastic facilities connected below ground.
 - (3) Inadequate cover.
 - (4) Activities in the vicinity of the pipeline that do not require one-call notification (e.g., new road construction, blasting, logging, deep tilling, land leveling).
 - (5) Excavation by agencies that are exempt from one-call notification.
 - (6) Ability to locate (see 12.4(a)(4) above).
 - (7) Pipe installed in casing.

12.7 *Incorrect operations (includes human error).*

- (a) All facilities are subject to the threat of incorrect operations. This threat is time-independent and may occur at any time. Potential incorrect operation threats include the following.
 - (1) Failure to follow correct operating procedures.
 - (2) Following incorrect, outdated, or incomplete operating procedures.
 - (3) Unqualified person performing an unfamiliar task.
 - (4) Use of uncalibrated or unauthorized tools.
- (b) Data collection.
ASME B31.8S Appendix A8 relates to metallic pipelines, but offers a useful format for data that should be collected to evaluate a plastic pipeline for incorrect operations. The following list may

be applicable to plastic pipelines and should be considered by the operator.

- (1) Procedure review information.
The procedure review for completeness and effectiveness should include the following.
 - (i) Procedural manual for operations, maintenance, and emergencies.
 - (ii) Damage prevention program.
 - (iii) Operator qualification program.
 - (iv) Anti-drug and alcohol program.
 - (v) Safety manual.
 - (vi) IMP periodic evaluations.
 - (vii) Adherence to operator procedures.
 - (viii) Operator procedures for conducting post-incident, abnormal operations, and failure investigations.
- (2) Audit information.
The results of both internal and external audits should be reviewed. Internal audits might include self audits in the following areas.
 - (i) Field operations.
 - (A) Valve inspections and maintenance.
 - (B) Leak surveys.
 - (C) Cathodic protection of in-line metallic component or parts.
 - (D) Patrolling.
 - (ii) Construction activities.
 - (iii) Office operations (e.g., documentation, processes).
 - (iv) Mapping.
- (3) Failures caused by incorrect operations.
Failures or potential failures caused by an incorrect operation may be found in the following reports.
 - (i) Abnormal operations.
 - (ii) Safety-related conditions.
 - (iii) Root-cause analysis.
 - (iv) Incidents.
 - (v) Near misses.
 - (vi) OQ disqualifications.

12.8 *Weather-related and outside forces.*

Weather-related and outside force threats have the capability to create extreme loading conditions on plastic pipelines (see guide material under §§192.317 and 192.615).

- (a) Potential weather-related and outside forces threats include the following.

- (1) Flooding (see 6 of the guide material under §192.613).
- (2) Frost heave.
- (3) Earthquakes.
- (4) Landslides.
- (5) Subsidence.
- (6) Extreme loads (e.g., equipment crossings).

- (b) Data collection.

ASME B31.8S, Appendix A9 generally relates to metallic pipelines, but may be useful as a format for data that should be collected to evaluate a plastic pipeline for weather and outside force damage. The following may be applicable to plastic pipelines and should be considered by the operator.

- (1) Pipe joining method.
Pipelines that include the following joint types may be more susceptible to leakage or failure from the threat of weather-related and outside forces than pipelines constructed using modern joining methods.
 - (i) Mechanical fittings that do not have restraints to prevent pipe pull-out.
 - (ii) Solvent cement.

- (iii) Adhesive.
- (iv) Heat fusions with a history of poor or cold fusions.
- (2) Topography and soil conditions.
The following topographical areas should be examined to determine if the threat associated with extreme loading conditions exists.
 - (i) Slopes prone to movement or other unstable areas that would induce additional stresses in a pipeline due to the movement of soil.
 - (ii) Extremely saturated soils that produce buoyant forces on pipelines.
 - (A) River and stream crossings.
 - (B) Low lands, floodplains, and swamps.
 - (C) Coastal areas prone to tidal surges from hurricanes or tropical storms.
 - (iii) Areas with deep frost line depths.
 - (iv) Highly expansive or unstable soils (e.g., some clays).
 - (v) Locations with known geologic conditions that contribute to instability (e.g., karst topography, sinkholes, underground mining, other subsidence areas).
- (3) Fault zones.
The following should be considered in evaluating an earthquake fault zone condition.
 - (i) Proximity of earthquake fault zones to pipeline location.
 - (ii) Previous earthquake activity.
 - (iii) Probability of future earthquake activity along fault.
 - (iv) Analyses of leaks or other damage attributable to earthquake activity.
- (4) Weather-related conditions.
Excessive loading from weather-related conditions that are likely to occur should be considered.
 - (i) Tidal surges from hurricanes or tropical storms in coastal areas.
 - (ii) Flooding or erosion.
 - (iii) Tornado activity or high winds.
 - (iv) Heavy snow or ice loading, or frost heave.
 - (v) Significant lightning.
- (5) Year of installation.
Some older pipeline facilities were constructed with materials and techniques that are generally not equivalent to modern facilities in terms of strength and integrity. The risk attributable to weather-related and outside forces threat may be commensurate with the age of the pipeline facilities.
- (6) Pipe parameters.
The following pipe parameters indicate capacity to resist weather-related and outside forces.
 - (i) Pipe material and density classification (e.g., high-density, medium-density).
 - (ii) Specified wall thickness.
 - (iii) Specified outside diameter.
 - (iv) Standard dimension ratio (SDR).
- (7) Operations and maintenance records.
Operators should also review operations and maintenance records (e.g., leak data, patrol data) to determine whether extreme loading conditions are present on their pipelines.

12.9 *Other threats unique to plastic pipelines.*

Other threats to plastic pipelines generally depend on the environment surrounding the pipeline location and might include the following.

- (a) Gophers, Palo Verde beetle, and other animals.
- (b) Deleterious chemicals in the soil, casing, groundwater, gas composition, or odorant.
- (c) Tree roots exerting a squeezing or rubbing force.
- (d) Abrasion caused by differential ground movement.
- (e) Squeeze-offs performed during maintenance or emergencies.
- (f) External or internal corrosion of metallic pipeline fittings or components.

- (g) Length of time exposed to UV prior to installation.
- (h) Re-pressure test.
- (i) Cross bores

13 DATA INTEGRATION

13.1 *General.*

- (a) Integrity management begins with an understanding of the pipeline through evaluation of data that is often collected for other regulatory and operational purposes. This data should not be handled in isolation, but may need to be shared with persons responsible for other aspects of pipeline operation. Collection and understanding the relevant information is the first step in establishing an integrity management program. Data integration may illuminate situations that are in need of attention, or highlight conditions that are valuable for safe operation and should be emulated on other portions of the pipeline.
- (b) Data integration involves merging individual data elements (aggregation) and analyzing them in their combined context (integration) to identify and evaluate potential threats to the pipeline segment. Data integration may allow an operator to discover threats and risks to a pipeline that would not otherwise appear obvious from a review of the various individual data elements on their own.
- (c) The operator's data integration procedure should encompass the ability to merge and use the multiple data elements gathered as described in 3 through 12 above. The operator is required by §192.917(b) to consider data from both covered and similar non-covered segments of the pipeline. Therefore, the operator should consider the following.
 - (1) Past incident history including abnormal operations and safety-related condition reports.
 - (2) Corrosion control records including pipe inspection reports, CIS, or other surveys.
 - (3) Continuing surveillance records.
 - (4) Patrolling records.
 - (5) Maintenance history.
 - (6) Internal inspection records.
 - (7) ILI results.
 - (8) Direct examinations from direct assessment applications.
 - (9) Other conditions specific to each pipeline (e.g., one-call and construction activity, third-party damage).
- (d) Section 192.947 requires an operator to maintain records that demonstrate data relevant to a particular covered segment was considered in making decisions.
- (e) A periodic review should be conducted to determine if data integration and analysis accurately reflect the pipeline conditions. This activity should be an element of the quality assurance program (see §192.911(l)).

13.2 *Common reference system.*

One of the first steps in data integration is the development or verification of a common reference system with consistent measurement units. This allows data elements from various sources to be aggregated and then accurately associated with locations on the pipeline that are point or section specific (e.g., a point on a pipeline that failed versus a river crossing).

The operator may need to combine stationing or mile posts with discrete measurements from various integrity tools, such as ILI or CIS, and GPS readings. The operator should have accurate knowledge of the location (e.g., centerline) of the pipeline and should be able to demonstrate how the location has been verified.

13.3 *Data alignment methods.*

- (a) General.
Data alignment may be performed manually or electronically. Regardless of the method, there are potential problems associated with data alignment. These include ensuring accuracy of data

locations, plotting start/stop points for various surveys, using paper data versus electronic data, or plotting combinations of manual or electronic data.

- (b) **Manual.**
Manual integration generally consists of superimposing data elements on a representation of the pipeline, such as a map or aerial photograph. Locations may be relative to pipeline stationing, permanent landmarks, lot line dimensions, or other means that can be applied consistently along the pipeline.
- (c) **Electronic.**
Numerous geospatial systems are available that support overlaying data elements based on an electronic location identifier. These are generally referred to as geographic information systems (GIS) or management information systems (MIS). To secure the location of the data being processed, most use latitude and longitude which may be obtained from satellite-based GPS devices. When aligning data from various GPS surveys the operator should be aware that GPS accuracy may change based on the equipment used and conditions at time of the survey. See guide material under §192.614.
- (d) In some cases, an operator's risk assessment software may be able to perform the data alignment described. Specialty data alignment and integration software programs are also available.

13.4 *Integration.*

- (a) **General.**
Data organization alone does not constitute data integration. Knowledgeable personnel should use the information to perform data integration in making decisions and conclusions that consider the relevant data. Data elements applicable to each covered segment should be analyzed in a structured manner. Analysis includes determining the effect various data elements have on the other elements present on the pipeline segment. Depending on the conditions, analysis may encompass the entire segment or be focused on localized areas of interest. Section 192.917(b) requires that information from similar non-covered segments must be included when it is relevant to the analysis being performed.
- (b) **Third-party damage evaluation.**
Section 192.917(e)(1) requires the integration of the results of ILI or ECDA assessments with data on encroachments or foreign line crossings affecting the pipeline. This effort will define locations of potential excavation or other subsurface (e.g., post driving) damage that may have been otherwise unknown.
- (c) **Continuous improvement.**
As integrity assessments are completed, the results should be reintegrated with current attribute and historic assessment data to determine whether changes that require action have occurred. For example, if a metal loss ILI tool and a crack detection ILI tool are both run on the same segment, the interaction between wall loss anomalies and crack anomalies should be evaluated. See guide material under §192.937.

13.5 *Similar non-covered segments.*

Determining "similar non-covered pipeline segments" (i.e., those not in an HCA) generally involves the comparison of physical pipeline attributes, operating and maintenance history, environment where it is installed, and results of assessments performed in conjunction with covered segment assessments (e.g., included in the same ILI run). Section 192.917(e)(5) also identifies material coating and environmental characteristics as considerations for determining if a segment is similar to a covered segment where external corrosion is an identified threat.

14 **THREAT STATUS**

- (a) **Active Threats**
 - (1) Threats deemed active require an integrity assessment (see 3 of the guide material under §192.919).

- (2) An operator should evaluate whether cyclic fatigue or other external loading conditions (e.g., ground movement, suspension bridges) could interact with any of the active nine threats referenced in ASME B31.8S and increase the potential for failure.

(b) Inactive Threats

- (1) If an operator determines that pipeline segments are not susceptible to specific threats, the threat status may be deemed inactive. Justification and documentation supporting that conclusion should be maintained. The lack of required data should not justify specifying a threat as inactive.
- (2) A threat may become inactive over time due to pipeline replacement programs, the implementation of effective preventative actions, or other improvements to systems.
- (3) An inactive threat might become active as a result of changes or information gained.
- (4) Documents to support the determination of an inactive threat status are to be maintained per §192.947(d).
- (5) As periodic integration of pipeline information is completed (see guide material under §192.937), the operator should re-examine each applicable threat to determine its active or inactive status.
- (6) Cyclic fatigue is a concern because it could interact with all other threats. The operator should have system specific data applicable to its unique operating environment to justify that cyclic fatigue is not a concern. A system-wide or generic study of cyclic fatigue may be used by an operator if the operator documents why the study is applicable to the segment-specific conditions.
- (7) An operator does not need to assess a threat for the current assessment cycle if that threat status is determined inactive.

Threat	Considerations for Active Status	Considerations for Inactive Status
External Corrosion	<ul style="list-style-type: none"> • Metallic pipe- always active • Note: Operator must protect metallic pipelines per Subpart I 	<ul style="list-style-type: none"> • Plastic Pipe- always inactive
Internal Corrosion	<ul style="list-style-type: none"> • Production, storage, or non-pipeline-quality gas transported at any time during the history of the pipeline • Pipeline has been converted from another type of service that is susceptible to internal corrosion • Presence of unmonitored or inoperative known drips, siphons, dead legs, or other liquid holdup points • Evidence of liquids from drips, siphons, dead legs, or other liquid holdup points • Pipe inspection reports indicating evidence of internal corrosion • Lack of complete pipeline operating history, in-line inspection, or ICDA 	<ul style="list-style-type: none"> • It can be demonstrated that a corrosive gas is not being transported, per §192.475(a) • In-line inspection data confirms that a corrosive environment does not exist within the pipeline • ICDA demonstrates that there is no internal corrosion occurring at the most likely locations • Plastic pipe- always inactive
Manufacturing	<ul style="list-style-type: none"> • Steel pipe vintages with a known history of manufacturing defects • Pipe has joint factor of <1.0 • Pipeline is comprised of low-frequency-welded ERW pipe or flash-welded pipe 	<p>None of the following have occurred.</p> <ul style="list-style-type: none"> • Operating pressure increases above the maximum operating pressure experienced during the preceding five years • MAOP increases • Stresses that lead to cyclic fatigue increase

Construction	<ul style="list-style-type: none"> • Mechanically coupled pipelines • Pipelines joined by means of acetylene girth welds • For girth welds, welding procedures and NDT information are not available to ascertain that the welds are adequate • For fabrication welds, the welding procedures and NDT information are not available to ascertain that the welds are adequate • For wrinkle bends and buckles as well as couplings, reports of visual inspection are not available to review and ascertain their continued integrity • Potential movement of the pipeline from ground settlement or other outside loads causing lateral or axial stresses 	<p>None of the following have occurred.</p> <ul style="list-style-type: none"> • Operating pressure increases above the maximum operating pressure experienced during the preceding five years • MAOP increases • Stresses that lead to cyclic fatigue increase
Equipment	<ul style="list-style-type: none"> • Equipment issues are identified during normal maintenance activities, per the requirements of the O&M procedures • Equipment that is the cause of abnormal operations, failure, accident, or incident 	<ul style="list-style-type: none"> • History and review of the records, as required by §192.613, 192.617, 192.603, 192.605, 192.739, and 192.743 • Review of operating history failures and abnormal operations records, as evaluated by integrity personnel, determines no unusual trends and no new issues • Status of existing preventative measures and mitigative measures deemed effective
Third-Party Damage	<ul style="list-style-type: none"> • Always active • Operator must (§192.935(b)(1)) monitor excavation activities and damages 	
Incorrect Operations	<ul style="list-style-type: none"> • Always active • Operator must (§192.617) evaluate failures and determine if incorrect operations lead to the failure 	
Weather-Related and Outside Forces	<p>Always active</p> <p>Operator must (§192.935(b)(2)) monitor and take measures to reduce the risk from weather related and outside force damage</p>	

TABLE 192.917ii

15 RISK ASSESSMENT

15.1 General.

Risk is generally defined as the probability of failure times the consequence of failure. Risk analysis is used to determine which threats need to be assessed, prioritize segments to be assessed, and determine the most effective preventative and mitigative measures. Analysis of the resulting risk scores should include evaluation of the current and potential risks posed by each threat that is applicable to a segment, as well as a total risk to a segment represented by combining scores for all threats to that

segment. The risk evaluation also needs to account for threat interaction (e.g., the potential increased risk for external corrosion posed by excavation activities, or the increased risk to construction defects by potential stresses from outside forces). See ASME B31.8S, Paragraph 2.2. Regardless of the method chosen for risk assessment, risk is relative only to a particular operator.

15.2 Likelihood of failure.

See 3 through 12 above which include factors that should be evaluated when determining the likelihood of failure.

15.3 Consequence of failure.

Risk consequences consider the potential impact of the event on individuals, property, business, and the environment. Operators should maintain a focus on the risk of failures to high consequence areas. Consequence factors may include the following.

- (a) Segment is in an HCA.
- (b) Population density or class location.
- (c) Proximity to populations with limited mobility (e.g., hospitals, nursing homes, child care facilities, prisons, sports arenas).
- (d) Might the predicted failure lead to a leak or rupture.
- (e) Loss of gas supply and impacts on service (e.g., customer load, number of customers, electric generation).

15.4 Risk assessment models.

ASME B31.8S, Paragraph 5.5 lists the following four approaches to risk assessment.

- (a) Subject matter expert (SME) risk models.
A qualitative risk model providing a relative ranking of risks based on input of SMEs knowledgeable of a pipeline system and the associated threats. Such knowledge should be combined with information from technical literature to evaluate the risk of various threats. See guide material under §192.3 for the definition of SME.
- (b) Relative risk assessment models.
Relative risk assessment models are generally algorithm-based computer applications that use extensive operator and industry data to weight the major threats and consequences relevant to past (and predicted future, when applicable) pipeline operations.
- (c) Scenario-based risk models.
A scenario-based model uses event trees, decision trees, and fault trees to outline a series of possible events to determine the likelihood and consequences of the events.
- (d) Probabilistic-based risk models.
Probabilistic-based risk models are quantitative in approach. They are the most complex and most demanding with respect to data requirements. These models calculate the risk as the product of the probability of failure and its associated consequences, which are then compared to acceptable risk levels established by the operator.
- (e) See 15.1.16 below for a reference providing additional information on risk assessment.

15.5 Selection of risk model.

The approach selected by the operator should have the following characteristics.

- (a) Identification of potential events or conditions that are threats to system integrity.
- (b) Evaluation of likelihood and consequences of failure.
- (c) Determination of risk ranking to prioritize integrity assessments.
- (d) Development of mitigating action.
- (e) Provision for data feedback and validation.
- (f) Continuous updating for risk assessments and to enhance its effectiveness.

15.6 Risk reassessments.

Section 192.937 requires that risk be reassessed. The risk model should be updated, as appropriate, and rerun based on changes to the system parameters, including the following (see guide material

under §192.937).

- (a) Changes to the pipeline system or its operations.
- (b) External changes in the pipeline's physical environment.
- (c) Enhancements in data gathering techniques.
- (d) New information relevant to the integrity analysis.
- (e) Results of assessments.
- (f) Results of remediation.
- (g) Results of preventive and mitigative measures.

The operator must have a documented process in place to consistently perform this risk reassessment with decisions documented in supporting the sustainability of the integrity program (see §192.947).

15.7 *Validation.*

Validation of the risk assessment results is an ongoing process ensuring that the methods used have produced results consistent across the pipeline system and with other industry experience. The validation is a review to determine whether the integrity assessment results are as expected. Additionally, spot inspections in the field and evaluations of low-risk and high-risk pipeline segments may be performed to validate that the model is correctly characterizing the risks. When an operator obtains additional data that may affect the outcome and corresponding rankings, the risk assessment process and associated schedules and procedures should be modified using the operator's management of change process (see guide material under §192.911). Additional data can include information from pipeline maintenance or other activities that identify inaccuracies in the characterization of risk for the pipeline segment or other similar segments. Validation may be performed by one or more of the following.

- (a) An analysis by SMEs.
- (b) Modeling known failures to determine if the results produce high risk.
- (c) Comparison to another model.
- (d) Comparison of results with expectations.

If there are discrepancies in the validation, it does not necessarily mean that the risk ranking is wrong. What it does indicate is that there is a difference that needs to be understood. It could be that the risk model failed to incorporate some important factors, or it may be that there are factors important to risk that SMEs and operations personnel did not recognize because they have never faced them. It is important that the operator understands the reasons for the difference, makes necessary adjustments to its risk assessment, and has confidence that the final results accurately represent its system.

15.8 *Records.*

An operator is required to document the risk assessment (§192.947(b)). See guide material under §192.947.

16 REFERENCES

16.1 *Steel pipe.*

- 16.1.1 Chapter V of GPTC-Z380-TR-1, "Review of Integrity Management for Natural Gas Transmission Pipelines," an ANSI Technical Report by GPTC, November 18, 2001 (Withdrawn 3/30/12), AGA Catalog Number X69806; available at GPTC website.
- 16.1.2 "Improvement of External Corrosion Direct Assessment Methodology by Incorporating Soils Data," <https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=118>.
- 16.1.3 "Field Guide for Investigating Internal Corrosion of Pipelines," Richard Eckert, published by NACE International, 2003.
- 16.1.4 GRI-02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology" (see listing in §192.7, not IBR for §192.917).
- 16.1.5 NACE SP0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems."
- 16.1.6 Section 4.3.2 of NACE SP0192-12, "Monitoring Corrosion in Oil and Gas Production with Iron

Counts."

- 16.1.7 NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."
- 16.1.8 OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study", Michael Baker Jr., Inc., January 2005, at:
http://primis.phmsa.dot.gov/iim/docstr/SCC_Report-Final_Report_with_Database.pdf.
- 16.1.9 ASME 100396, "History of Line Pipe Manufacturing in North America."
- 16.1.10 "Integrity Characteristics of Vintage Pipelines," INGAA.
- 16.1.11 "Dealing with Low-Frequency-Welded ERW Pipe and Flashwelded Pipe with Respect to HCA-Related Integrity Assessments," John F. Kiefner, 2002, www.kiefner.com.
- 16.1.12 OPS Technical Task Order Number 5, "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation," Final Report, Michael Baker Jr., Inc., et al, at:
http://primis.phmsa.dot.gov/iim/docstr/TTO5_LowFrequencyERW_FinalReport_Rev3_April2004.pdf.
- 16.1.13 OPS Alert Notices and Advisory Bulletin:

ALN-88-01 (Jan 28, 1988)	Operational failures of pipelines constructed with ERW prior to 1970
ALN-89-01 (Mar 8, 1989)	Update to ALN-88-01
ADB-09-01 (74 FR 23930, May 21, 2009)	Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe.

- 16.1.14 "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines," Final Report 05-12R, John F. Keifner, 2007, at:
http://primis.phmsa.dot.gov/gasimp/docs/Evaluating_Stability_of_Defects.pdf.
- 16.1.15 Section 841.231 of ASME B31.8, "Gas Transmission and Distribution Piping Systems" (see listing in §192.7, not IBR for §192.917).
- 16.1.16 "Pipeline Risk Management Manual," W. Kent Muhlbauer, Gulf Publishing Company, ISBN: 0750675799.

16.2 *Plastic pipe.*

- 16.2.1 OPS Advisory Bulletins:

ADB-86-02 (Feb. 26, 1986)	Plastic Piping, Mechanical Coupling
ADB-99-01 (64 FR 12211, Mar. 11, 1999)	Susceptibility of Certain Polyethylene Pipe Manufactured by Century Utility Products, Inc. to Premature Failure Due to Brittle-Like Cracking
ADB-99-02 (64 FR 12212 Mar. 11, 1999)	Potential Susceptibility of Plastic Pipe Installed Between the [Years] 1960 and the Early 1980s to Premature Failure Due to Brittle-Like Cracking
ADB-02-07 (67 FR 70806, Nov. 26, 2002)	Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe
ADB-02-07 Corr. (67 FR 72027, Dec. 03, 2002)	Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe; Notice; correction
ADB-07-02 (72 FR 51301, Sept. 6, 2007)	Updated Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe
ADB-07-02 Corr. (73 FR 11192, Feb. 29, 2008)	Updated Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe
ADB-12-03 (77 FR 13387, Mar. 6, 2012)	Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation

- 16.2.2 Plastic Pipe Database Committee (PPDC) reports at:
www.aga.org/Kc/OperationsEngineering/ppdc/Status%20Reports/Pages/default.aspx
- 16.2.3 Section 4 of Guide Material Appendix G-192-8, Distribution Integrity Management Program (DIMP).
- 16.2.4 API Specification 15HR High-Pressure Fiberglass Line Pipe.

16.3 *Applicable to both steel and plastic pipe.*

- 16.3.1 "Results of State Damage Prevention Program Characterizations," at:
<https://primis.phmsa.dot.gov/comm/sdppcdiscussion.htm>
- 16.3.2 "Guideline for Assessing the Performance of Oil and Natural Gas Pipeline Systems in Natural Hazard and Human Threat Events," American Lifelines Alliance.

§192.919

What must be in the baseline assessment plan?

[Effective Date: 02/14/04]

- An operator must include each of the following elements in its written baseline assessment plan:**
- (a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See §192.917.);
 - (b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (See §192.917.) More than one method may be required to address all the threats to the covered pipeline segment;
 - (c) A schedule for completing the integrity assessment of all covered segments, including, risk

factors considered in establishing the assessment schedule;

(d) If applicable, a direct assessment plan that meets the requirements of §§192.923, and depending on the threat to be addressed, of §192.925, §192.927, or §192.929; and

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

[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 GENERAL

- (a) An operator with multiple operating companies may have a separate baseline assessment plan (BAP) for each operating company or separate legal entity, or a single plan covering all operating companies. If operations include both interstate and intrastate pipelines, the operator may consider delineating whether each covered pipeline segment is part of an interstate or intrastate pipeline. When a risk assessment is unable to result in comparable risk rankings, such as between steel and plastic pipelines, a separate baseline assessment plan may be considered. See guide material under §192.917.
- (1) Each BAP is required to meet §192.919.
 - (2) All covered segments are required to be addressed in a BAP.
- (b) When developing a BAP, the operator should consider the following.
- (1) HCA information.
 - (i) HCA designation (e.g., numeric).
 - (ii) Covered segment identification (including interstate or intrastate pipeline).
 - (iii) Location.
 - (iv) HCA type (method to determine HCA, identified site, house count, location).
 - (v) Covered segment information (e.g., length, diameter, MAOP, percent of SMYS, maximum actual operating pressure, piggable).
 - (vi) Potential impact circle (see §192.905).
 - (vii) Risk score (may be numeric or qualitative) and the date it was determined.
 - (2) Assessment information.
 - (i) Current year assessment information.
 - (A) Covered segment identification.
 - (B) Risk rank.
 - (C) Applicable threats.
 - (D) Assessment type.
 - (E) Assessment method.
 - (F) Schedule.
 - (G) Cost estimate (excluding remediation).
 - (H) Potential scheduling constraints.
 - (ii) Future year assessment information.
 - (A) Covered segment identification.
 - (B) Risk rank.
 - (C) Applicable threats.
 - (D) Assessment type.
 - (E) Assessment method.
 - (F) Schedule year.
 - (3) Baseline assessment target.
 - (i) Covered segment identification.
 - (ii) HCA designation and location.
 - (iii) A risk score and ranking of all HCAs or covered segments.
 - (iv) Covered footage.

- (v) Target footage assessed per year.
- (vi) Cumulative footage.
- (vii) Confirmation that 50% completed by December 17, 2007.
- (4) Current year assessment schedule.
 - (i) HCA designation.
 - (ii) Covered segment identification.
 - (iii) Tasks.
 - (iv) Milestones.
 - (v) Completion date.
- (c) BAP modifications.

The BAP is required to be modified when the operator gains more knowledge through the initial (baseline) assessments, risk assessments, assessment methods, or other improvements to its program. For example, a risk assessment can lead to changes in inspection priorities that will lead to a BAP modification. The operator is required to document all BAP modifications and the reason for the changes. Modifications made to the BAP are required to be accomplished in accordance with the operator's management of change process. See §192.911(k). This documentation must be available for regulatory review.

2 IDENTIFYING POTENTIAL THREATS

- (a) For threat identification, see §192.917(a).
- (b) Undiscovered third-party damage.
 - (1) The operator is required to develop procedures in its integrity management program addressing how it will respond when the data integration activities provide an indication that undiscovered third-party damage may have occurred on a covered segment.
 - (2) The threat of undiscovered third-party damage is the result of a localized, time-independent event. Procedures are required to cover response where the data integration suggests evidence of an undiscovered third-party defect. The procedures should require direct examination of the pipeline to identify or characterize damage. NDE should be used if necessary.
 - (3) Data gathered from the evaluation of undiscovered third-party defects should be considered when evaluating data for the entire covered segment and the need for additional surveys and actions taken to ensure the integrity of the covered segment.

3 SELECTING ASSESSMENT METHOD

- (a) The method(s) selected must be appropriate to address all the identified threats applicable to the covered segment being assessed.
- (b) It may be necessary to consider a combination of tools or techniques of integrity assessment to directly address the primary threats. Table 192.919i may be used as a guide to identify appropriate assessment methods for the various primary threats. Additional information can be found in ASME B31.8S–2004, Section 6 (see listing in §192.7, not IBR for §192.919).
- (c) To determine the most appropriate assessment method(s) for identifying anomalies associated with specific threats for the covered segment, consideration should be given to documenting the basis for method selection. Assessment methods and some reasons for choosing them are as follows.
 - (1) In-line inspection (ILI).
 - (i) Expected anomalies and inspection objectives.
 - (ii) Construction, design, or operating characteristics of covered segment.
 - (iii) Gas supply deliverability.
 - (iv) Capabilities and performance, such as detection sensitivity, anomaly classification, sizing accuracy, and location accuracy.
 - (v) Location and accessibility for direct examination.
 - (vi) History of tool.
 - (vii) Ability to inspect full length and full circumference of the section.
 - (viii) Ability to indicate the presence of multiple cause anomalies.

- (2) Pressure test.
 - (i) Expected anomalies and inspection objectives.
 - (ii) Construction, design, or operating characteristics of covered segment.
 - (iii) Gas supply deliverability.
 - (iv) Accessibility to the supply and disposal of test medium.
 - (v) Location of pipeline segment with regard to environmentally sensitive areas.
 - (vi) Ability to conduct pressure test in accordance with the requirements of 49 CFR Part 192, Subpart J.
 - (vii) A hydrostatic test meeting Subpart J requirements is sufficient to demonstrate that manufacturing and construction defects will remain stable at the operating pressures related to that test. Operators do not need to consider the operating pressure in the five years preceding HCA identification for segments that have passed a hydrostatic test in accordance with Subpart J.
- (3) Direct assessment.
 - (i) Expected anomalies and inspection objectives.
 - (ii) Construction, design, or operating characteristics of covered segment.
 - (iii) Ground overlay (e.g. asphalt, concrete) above covered segment.
 - (iv) If direct assessment methods are used, develop direct assessment plans describing how they will be used.
 - (v) Ensure indirect inspections can be made over the entire length of an ECDA region with both complimentary tools.
- (4) Other technology.
 - (i) When an operator plans to use other technology in accordance with §192.921(a)(4), the operator needs to notify and provide documentation demonstrating the appropriateness of the technology to PHMSA-OPS at least 180 days before conducting an assessment using such a method.
 - (ii) Ensure that state or local pipeline safety authorities are notified 180 days before conducting the assessment on an intrastate covered segment.
- (d) Inspection using any of the methods identified in Table 192.919i may not be appropriate for certain threats, such as Third-Party Damage, Equipment Defect, Weather Event, or Incorrect Operations. For these threats, other actions such as prevention and mitigation may provide better integrity management results. See §192.935.
- (e) In selecting an assessment method for the threat of third-party damage, the operator should consider the following.
 - (1) If the threat of a future third-party damage event is expected to be present in covered segments. In such cases, prevention of future events is better addressed under the requirements for preventive and mitigative actions.
 - (2) If as part of a baseline assessment or reassessment, the operator has gathered data from an ECDA or internal-inspection tool survey correlating to third-party damage.
 - (i) Further action must be taken to look for third-party damage events that did not result in immediate failure, but may have resulted in undiscovered damage that could fail in the future.
 - (ii) The rule requires that the data gathered as a result of the ECDA or internal-inspection tool surveys be integrated with data relevant to third-party activity, such as encroachments or foreign line crossings.
 - (iii) Areas in which anomalies from an internal inspection or ECDA survey align with possible indicators of third-party activity provide potential indications of undiscovered third-party damage in the covered segment.

ASSESSMENT APPLICABILITY (Based on ASME B31.8S-2004, Section 6 — see §192.7 for IBR)									
Threat abbreviations:									
EC – External Corrosion			IC – Internal Corrosion			SCC – Stress Corrosion Cracking			
MFG – Manufacturer Defect			CON – Construction Defect			EQP – Equipment Defect			
EXD – Excavation Damage			WOF – Weather Related & Outside Force			IO – Incorrect Operation			
Assessment Methods	Primary Threats								
	EC	IC	SCC	MFG	CON	EQP	EXD	WOF	IO
In-Line Inspection (ILI) Tools									
Magnetic Flux Leakage, Std Res.	X	X							
Magnetic Flux Leakage, High Res.	X	X					X		
Ultrasonic Compression Wave	X	X		X			X		
Ultrasonic Shear Wave Tool	X	X	X	X			X		
Transverse Flux	X	X		X			X		
Deformation or Geometry					X		X	X	
Pressure Test	X	X	X	X	X	X			
Direct Assessment									
ECDA ¹	X						X		
ICDA		X							
SCCDA			X						
Confirmatory Direct Assessment ²	X	X							
¹ ECDA can discover coating damage, including that caused by excavation activities; however, ECDA does not directly identify excavation damage. ² Confirmatory direct assessment can be used for assessments conducted at no longer than seven-year intervals when reassessments conducted using ILI, Pressure Test, or DA specified methods are scheduled to occur at intervals longer than 7 years, and when the threats of concern are corrosion.									

TABLE 192.919i

4 INTEGRITY ASSESSMENT SCHEDULE

- (a) The precision of the dates in the schedule may vary depending on how far in the future the assessments are scheduled.
- (b) Consider updating the baseline assessment plan schedule annually. Include all covered segments not already assessed, new segments added within the past year, and completed baseline assessments.

5 SAFETY AND ENVIRONMENTAL RISKS

When assessments are to be conducted by outside service providers, copies of their Health, Safety and Environmental procedure should be obtained, reviewed, and retained.

§192.921

How is the baseline assessment to be conducted?

[Effective Date: 07/10/06]

(a) **Assessment methods.** An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) **Prioritizing segments.** An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) **Assessment for particular threats.** In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) **Time period.** An operator must prioritize all the covered segments for assessment in accordance with §192.917(c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) **Prior assessment.** An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) **Newly-identified areas.** When an operator identifies a new high consequence area (see §192.905), an operator must complete the baseline assessment of the line pipe in the newly- identified high consequence area within ten (10) years from the date the area is identified.

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

(h) **Plastic transmission pipeline.** If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in

accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

[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]

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 ASSESSMENT METHOD

One, or more, of the methods listed below can be used for the assessment method. See Table 192.919i for related assessment applicability of (a), (b), and (c) below.

- (a) In-line inspections (ILI).
- (b) Pressure testing.
- (c) Direct Assessment (DA).
- (d) Other technologies.

1.1 *In-line inspection.*

- (a) Threat assessments.
Applicable ILI tools can be used to assess the following threats.
 - (1) External corrosion.
 - (2) Internal corrosion.
 - (3) Stress corrosion cracking.
 - (4) Manufacturing defects.
 - (5) Construction defects.
 - (6) Excavation damage.
 - (7) Weather and outside forces.
- (b) ILI tools.
Applicable tools and threats are listed in ASME B31.8S, Paragraph 6.2. Tools listed in that paragraph represent tested technology for the threats which the tools are capable of detecting. Other tools might meet the requirements of ASME B31.8S, Paragraph 6.2, provided they have a history of success and are capable of detecting the appropriate threat over the full length and circumference of the segment. If the tool does not have a history of success, it might be considered "other technology" and the requirements for using other technologies would need to be met.
- (c) Advantages of ILI.
 - (1) Assessments can generally be conducted without taking the pipeline out of service.
 - (2) Long segments of pipe can be assessed in a single run.
 - (3) More than one threat can be addressed in a single run.
 - (4) Multiple tools can be run at the same time.
 - (5) May assess multiple HCAs in a single run.
- (d) Disadvantages of ILI.
 - (1) Extensive pipe modifications may be required (e.g., installation of launcher/receiver, removal of restrictions).
 - (2) Flow rates and pressures must be within an acceptable range.
 - (3) Multiple tools may be needed to address multiple threats.
 - (4) Pipeline may need to be internally cleaned.
 - (5) Some tools require a liquid couplant.
 - (6) Scheduling limitations may include service interruptions and tool availability.
 - (7) Potential for failure or malfunction of ILI equipment.

- (e) For information on ILI tools and their use, see Guide Material Appendix G-192-14.

1.2 *Pressure testing.*

- (a) Threat assessments.

Pressure testing can be used to assess the following threats.

- (1) External corrosion.
- (2) Internal corrosion.
- (3) Stress corrosion cracking.
- (4) Manufacturing defects.
- (5) Construction defects.
- (6) Equipment defects.

- (b) Advantages of pressure testing.

- (1) Extensive pipeline modifications are generally not required.
- (2) Results are easy to interpret.
- (3) Multiple threats can be addressed at one time.

- (c) Disadvantages of pressure testing.

- (1) Pipeline must be taken out of service.
- (2) Acquisition and disposal of test medium.
- (3) Assessment provides only a pass/fail result.
- (4) Provides no information on non-critical defects (e.g., a 50% corrosion pit that did not fail).
- (5) Hydrostatic test dewatering and drying.
- (6) A failure during a pressure test may present safety and environmental risks.
- (7) Elevation changes may limit the amount of pipe that can be assessed in a single test.
- (8) Pressure testing could propagate existing flaws.
- (9) Scheduling limitations.

- (d) Test pressure.

In addition to considering the requirements of Subpart J, the operator may consider the reassessment interval indicated in ASME B31.8S, Section 5, Table 3 when choosing a test pressure. Choosing a test pressure higher than the pressure required by Subpart J may allow for a longer reassessment interval.

- (e) Conducting pressure tests.

See guide material under §§192.503, 192.505, and 192.919 plus Guide Material Appendices G-192-9 and G-192-9A.

1.3 *Direct assessment.*

- (a) Threat assessments.

DA can be used to assess the following threats.

- (1) External corrosion.
- (2) Internal corrosion.
- (3) Stress corrosion cracking.
- (4) Coating damage from excavation (see §192.917).

- (b) Advantages of DA.

- (1) Can be conducted without taking the pipeline out of service.
- (2) May be able to detect corrosive conditions before corrosion occurs.
- (3) Less intrusive to the operating pipeline.

- (c) Disadvantages of DA.

- (1) May require more excavations than ILI or pressure testing.
- (2) Only addresses corrosion threats.
- (3) Requires at least 2 complementary indirect inspection tools for ECDA.
- (4) ECDA is limited in areas of cased crossings.
- (5) May not work in inaccessible locations such as large bodies of water.
- (6) May not be able to assess pipe at greater than normal depths.

- (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 §192.18.

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.

§192.925

What are the requirements for using External Corrosion Direct Assessment (ECDA)?

Effective Date: 10/01/15]

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

(b) **General requirements.** An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.4, and in NACE SP0502 (incorporated by reference, see §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect inspection, direct examination, and post assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§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).

(1) **Preassessment.** In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 3, the plan's procedures for preassessment must include —

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

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) **Indirect inspection.** In addition to the requirements in ASME/ANSI B31.8S, section 6.4 and in NACE SP0502, section 4, the plan's procedures for indirect inspection of the ECDA regions must include —

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

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) **Direct examination.** In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 5, the plan's procedures for direct examination of indications from the indirect examination must include —

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

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502);

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

(iv) **Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502.**

(4) **Post assessment and continuing evaluation.** In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include —

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

(ii) **Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939. (See Appendix D of NACE SP0502.)**

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GUIDE MATERIAL

Note: References to NACE throughout this section of guide material are specific to the edition of NACE SP0502 as incorporated by reference (IBR) in §192.7. Abbreviated references are used in guide material below. Example: "NACE 5.2.1" means NACE SP0502, Paragraph 5.2.1 of the IBR edition. See 3 of the guide material under §192.907. NACE SP0502 is an IBR standard; therefore, "shall", "requires", or "must" statements in this section of guide material with specific reference to NACE SP0502 are required to be followed per §192.925(b).

1 PURPOSE

External Corrosion Direct Assessment (ECDA) is a methodology to assess the integrity of pipe and pipe coating that is subject to the threat of external corrosion. ECDA can discover existing external corrosion on steel and other ferrous pipe. A key advantage of ECDA, when compared to in-line inspection (ILI) and pressure testing, is its ability to detect coating damage before corrosion occurs.

2 GENERAL REQUIREMENTS

- (a) A written ECDA plan is required to be based on the following.
 - (1) Section 192.925.
 - (2) ASME B31.8S-2004, Paragraph 6.4 (see §192.7 for IBR).
 - (3) NACE SP0502.
- (b) The ECDA plan should include its purpose, objectives, and instructions to personnel.
- (c) Written procedures are required to address the following four process steps (see §192.925(b)).
 - (1) Pre-assessment.
 - (2) Indirect inspection.
 - (3) Direct examination.
 - (4) Post-assessment and continuing evaluation.
- (d) Section 192.947(d) requires documents to support decisions, analyses, and processes developed and used to implement and evaluate the operator's integrity management program including ECDA.
- (e) The ECDA plan may reference appropriate sections of other documents (e.g., survey procedures) instead of including them in the ECDA plan. These documents should be available to personnel performing associated tasks.
- (f) For first-time application of ECDA on a covered segment, the written procedure is required to address more restrictive criteria for each step of the ECDA assessment except for post-assessment.

Note: It is required that operators using ECDA develop and implement a direct assessment plan following ASME B31.8S and NACE SP0502 (see §192.925(b)). Some operators, however, may elect to organize the activities required within each of the 4 steps differently. For example, NACE SP0502 includes determining the minimum number of excavations (digs) in the direct examination step, whereas an operator may elect to include this item in its indirect inspection step. This re-organization of ECDA activities is generally acceptable, provided that all activities are addressed in the operator’s direct assessment plan.

3 PRE-ASSESSMENT STEP

The objectives of the pre-assessment step are to collect and analyze data to determine ECDA feasibility, define ECDA regions, and select indirect inspection tools.

3.1 Data collection.

- (a) An operator is required to define minimum data requirements based on the history and condition of the pipeline to determine the feasibility of ECDA (NACE 3.2.1.1). The operator is also required to define data elements for five pipeline data categories: pipe-related, construction-related, soils / environment, corrosion control, and operational data (NACE 3.2.2). NACE SP0502 provides examples of data elements for each category.

Table 192.925i provides examples of data elements that may be considered critical for justifying the feasibility of ECDA. The operator should document why a data element listed in NACE SP0502, Table 1 was or was not selected as critical. See §192.947(d).

Category	Examples of Critical Data Elements
Pipe-related	<ul style="list-style-type: none"> • Pipe material (e.g., steel) • Pipe bare or coated
Construction-related	<ul style="list-style-type: none"> • Location of known casings • Excessive depth that restricts indirect inspection tool use • Water crossings • Line crossings that affect CP • Location of high-voltage lines
Soils/Environment	<ul style="list-style-type: none"> • Soil characteristics (e.g., clay, rock) • Paved versus non-paved surfaces • Frozen ground
Corrosion Control	<ul style="list-style-type: none"> • CP type (anodes versus rectifiers) • Coating condition, such as disbonded coating
Operational Data	<ul style="list-style-type: none"> • Repair history (repair types, locations, and causes)

TABLE 192.925i

- (b) Data may be obtained from various sources, including the following.
- (1) Operating and maintenance records.
 - (2) Alignment sheets.
 - (3) Aerial photography.
 - (4) Risk assessment process.
 - (5) Subject matter expert input.
 - (6) Geographic information system (GIS).
 - (7) Field verification.

3.2 ECDA feasibility.

- (a) Analysis of data is required to determine if ECDA is feasible (NACE 3.3.1). This analysis should include determining the following.
 - (1) Does sufficient data exist about the covered segment to support the pre-assessment step?
 - (2) Is pipeline right-of-way accessible by personnel performing indirect inspections?
 - (3) Can indirect inspection tools be used over the pipeline?
 - (4) Do conditions exist that would make ECDA data difficult to interpret? These might include the following.
 - (i) Electric shielding of cathodic protection current.
 - (ii) Significant rock in the backfill or surrounding the pipe.
 - (iii) Other buried structure impacting electrical measurements.
 - (5) What other information does the operator deem appropriate for analysis (e.g., AC interference)?
- (b) Cased pipe can present challenges to conducting a successful integrity assessment using ECDA. NACE 3.3.2 states that there are locations where indirect inspections are not practicable such as certain cased crossings. Examples of factors that could make ECDA not feasible for cased crossings include the following.
 - (1) Lack of data about the carrier pipe or casing.
 - (2) Length of crossing.
 - (3) Depth of crossing.
- (c) If data cannot be collected to support the pre-assessment step, ECDA cannot be used as the primary integrity assessment method.
- (d) During the analysis of the data, if it is determined that other potential threats exist on the line, the operator should evaluate the significance of the other threat(s) and determine whether other assessment methods are appropriate.

3.3 Selection of indirect inspection tools.

- (a) The selection of indirect inspection tools is based on their ability to reliably detect potential corrosion activity or coating holidays. The operator is required to document the basis for tool selection (see §192.925(b)(1)(ii)). Factors to consider when documenting the basis include the following.
 - (1) Expected level of performance of each tool.
 - (2) The nature of the data or information that can reasonably be expected from each tool.
 - (3) Limitations of each tool.
- (b) Section 192.925(b)(1)(ii) requires a minimum of two complementary indirect inspection tools for each ECDA region within a covered pipeline segment. "*Complementary*" (as explained by NACE 3.4) is the strengths of one tool compensating for the limitations of another tool. For example, a strength of a close-interval survey is that it measures cathodic protection levels, but it is limited in its ability to identify coating holidays; whereas, a strength of a direct current voltage gradient (DCVG) survey is identifying coating holidays accurately, but it does not measure cathodic protection levels.

Examples of indirect inspection tools that are complementary include the following.

- (1) Close-interval and DCVG surveys.
 - (2) Close-interval and AC current attenuation (electromagnetic) surveys.
 - (3) Close-interval and alternating current voltage gradient (ACVG) surveys.
- (c) Indirect inspection tools not specifically listed in 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" (e.g., ultrasonics, guided wave) are allowed, but the operator is required to justify and document the following for any other inspection method that is used (see §192.925(b)(1)(ii)). See following note.
 - (1) Applicability.
 - (2) Validation basis.
 - (3) Utilization of data.

- (4) Equipment used.
- (5) Field procedure.

Note: Appendix A of the 2008 edition of NACE SP0502 listed several indirect inspection tools. During the revision and subsequent 2010 edition, NACE removed those indirect inspection tools from Appendix A to eliminate redundancy. However, when PHSMA adopted the 2010 edition of NACE SP0502, PHSMA did not revise §192.925(b)(1)(ii) to address this issue. Information regarding these indirect inspection tools formerly listed in Appendix A can now be found in NACE SP0207 and NACE TM0109.

3.4 Identification of ECDA regions.

- (a) ECDA regions must be determined for each covered segment (NACE 3.5.1). The primary objective for identifying different regions is to ensure that the proper indirect inspection methods are selected. A second objective is to identify the characteristics of the ECDA region that might influence the interpretation of the inspection data.
- (b) An ECDA region does not need to be contiguous and can exist on multiple pipelines or pipeline segments. For example, an ECDA region can be separated along the pipeline if similar characteristics exist on either side of a river crossing. See NACE 3.5.
- (c) An ECDA region is a section or sections of a pipeline that have the following.
 - (1) Similar physical characteristics, such as:
 - (i) Soil conditions.
 - (ii) Corrosion protection mechanisms.
 - (iii) River or large stream crossings.
 - (iv) Paved roads.
 - (v) Casings.
 - (vi) Designated wetlands.
 - (vii) Stray current areas.
 - (viii) Coating type and conditions.
 - (2) Similar operating histories, such as:
 - (i) Leakage.
 - (ii) Failures having the same root cause.
 - (iii) MAOP.
 - (3) Similar corrosion control histories, such as:
 - (i) CP system type (impressed versus galvanic).
 - (ii) CP criteria.
 - (iii) CP levels.
 - (iv) Corrosion control failures.
 - (v) Years without CP.
 - (4) Expected future corrosion conditions.
 - (5) Same indirect inspection tools to be applied.

Note: See NACE 2 and 3.5.1.1.1.
- (d) Region definitions or boundaries may change as more information is gathered through the ECDA process. Changes to regions and the reasons for changes must be documented (see §192.947(d)).

3.5 First-time application.

When conducting ECDA for the first time on a covered segment, an operator is required to apply more stringent pre-assessment criteria (see §192.925(b)(1)(i)), such as one or more of the following.

- (a) Select more than two indirect inspection tools.
- (b) Perform test-hole inspections to verify data or gather additional data. Examples include the following.
 - (1) Soil resistivity.
 - (2) Coating type and condition.
 - (3) Soil conditions.
- (c) Increase the number of ECDA regions.

4 INDIRECT INSPECTION STEP

4.1 General.

- (a) The objective of this step is to use aboveground inspection techniques to identify and define the severity of the following.
 - (1) Coating faults.
 - (2) Other anomalies (e.g., stray current interference, electrical shorts).
 - (3) Areas where corrosion activity (e.g., insufficient CP current) may have occurred or may be occurring.
- (b) In this step, two or more complementary indirect inspection tools are used over the entire covered pipeline segment to provide improved detection reliability under the wide variety of conditions that may be encountered.
- (c) This step is comprised of the following activities.
 - (1) Conduct indirect inspections.
 - (2) Align inspection data.
 - (3) Determine indications.
 - (4) Classify the severity of each indication.
 - (5) Compare results for consistency.

4.2 Conduct indirect inspections.

- (a) ECDA region boundaries. Prior to conducting the indirect inspections, the boundaries (i.e., start and stop) of each ECDA region are required to be identified unless the operator justifies and documents an alternative approach (NACE 4.2.1). Operators should consider noting the boundaries on an alignment sheet, pipeline map, or other document that indicates the covered segment to be inspected.
- (b) Indirect inspection procedures. Operators may develop their own or review and accept other established procedures. When developing the required written procedures, the following factors should be considered.
 - (1) Electrical and other safety precautions.
 - (2) Equipment and instrumentation operating and calibration instructions.
 - (3) IR drop considerations.
 - (4) Locating and marking pipe.
 - (5) Survey spacing interval.
 - (i) Routine survey.
 - (ii) Suspected anomaly.
 - (6) Data documentation.
 - (7) Data quality review and analysis.
- (c) Indirect inspection overlaps. To ensure that an inspection is conducted over the entire length of each ECDA region, operators should consider overlapping the inspections into adjacent regions.
- (d) Aboveground references.
 - (1) Aboveground location measurements are required to be referenced to precise geographical locations (e.g., global positioning system (GPS)) or permanent geographical features (e.g., edge of a road, isolation valve, valve basin cover, or test station) unless the operator justifies and documents an alternative approach (NACE 4.2.5).
 - (2) A sufficient number of easily located aboveground reference points should be identified to reduce spatial errors. These reference points should be documented to allow survey measurements to be aligned and used to identify excavation sites.
- (e) Changes to facilities. No major changes to a covered segment (e.g., installation or abandonment of a pipeline) should be made between the use of the first and second inspection tools.
- (f) Subsequent surveys. After completion of the first indirect inspection, the subsequent survey(s) should be done as soon as practicable to avoid changes in pipeline conditions. For example, seasonal changes affecting soil moisture content could make it difficult to correlate measurements between the surveys.

4.3 *Align inspection data.*

After the indirect inspection measurements are obtained, data from each tool is required to be aligned for comparison (NACE 4.3.1). An example of aligning inspection data may include the following.

- (a) First, align the data from the two or more tools for the region by comparing start and stop locations, as well as the aboveground reference locations. In effect, this is overlaying the two or more data sets on top of a virtual centerline for comparison.
- (b) Next, integrate the pre-assessment data for the ECDA region with the aligned tool data for comparison. Pre-assessment knowledge that could assist in data interpretation should be included. Examples of such knowledge include the following.
 - (1) Foreign line crossings.
 - (2) Pipe repairs.
 - (3) CP facilities.
 - (4) Third-party damages.
 - (5) Stray current locations.

4.4 *Determine indications.*

The aligned data are analyzed for indications. An "*indication*" is defined (NACE 2) as a deviation from the norm as measured by an indirect inspection tool. Since indirect inspection results will vary due to environmental factors (e.g., weather, water content in soil, signal interference), no single set of criteria will apply in all cases to define the extent of deviation that is of concern. Pre-assessment knowledge will help define threshold values from which to determine if indications exist.

- (a) At a minimum, criteria for identifying indications must be based on the following (see §192.925(b)(2)(ii)).
 - (1) Known sensitivities (i.e., limitations) of assessment tools.
 - (2) Procedures for using each tool (e.g., differences in procedures for an impressed current versus a sacrificial anode system may result in using different criteria).
 - (3) The operator's procedure for decreasing the spacing of readings when the presence of an anomaly is suspected.
- (b) In addition to the requirements of §192.925(b)(2)(ii), an operator may also consider the following.
 - (1) Single survey data that does not meet cathodic protection criteria.
 - (2) Dual survey data.

4.5 *Classify the severity of each indication.*

"*Classification*" of an indication is defined (by NACE 4.3.2.1) as the process of estimating the likelihood of corrosion activity at each indication under typical year-round conditions. NACE Table 3 provides guidance on establishing criteria for classifying indications. This table uses general terms such as "small dips" or "large signal loss." The operator should assign values to these general terms. For example, a "small CIS dip" could be defined as a "0.100 V dip within a 100 feet sample area." The values assigned to these terms may change based on variations of the pipeline characteristics or environment. The following overall severity classifications should be used.

- (a) Severe: highest likelihood of corrosion activity.
- (b) Moderate: possible corrosion activity.
- (c) Minor: lowest likelihood of corrosion activity.

4.6 *Compare results for geographic consistency.*

Classified indications from two or more complementary inspection tools must be compared to determine whether indications are associated with the same physical location along the pipe (NACE 4.3.3). If two or more indirect inspection tools indicate significantly different sets of locations where corrosion activity may exist, and if the differences cannot be explained by the inherent capabilities of the tools or specific and localized pipeline features or conditions, additional indirect inspections or preliminary direct examinations should be considered. Unacceptable spatial differences (as defined by the operator) may be a result of inaccurate GPS, inaccurate location of aboveground reference points, or errors in data alignment. The operator should first verify that spatial readings are accurate. If spatial differences remain and cannot be resolved by the pre-assessment data or inherent capabilities of the tools, the following

options should be considered.

- (a) Repeat the indirect inspection using the same tool over the location at the same or at a closer interval spacing.
- (b) Perform additional indirect inspections using a different tool over the location.
- (c) Perform a direct examination on the indications.
- (d) Classify the indications as severe.

4.7 *First-time application.*

When conducting ECDA for the first time on a covered segment, an operator is required to apply "more restrictive criteria" (see §192.925(b)(2)(i)). Examples of more restrictive criteria to apply include one or more of the following.

- (a) Take soil resistivity measurements.
- (b) Spot check readings by taking duplicate readings at different times at one or more locations along the indirect inspection path and compare for drift.
- (c) Repeat the indirect inspection in its entirety at a different time, and compare for consistency.
- (d) Repeat a portion of the survey in the opposite direction.
- (e) Decrease the distance between temporary markings (e.g., flags, paint).
- (f) Provide additional training of personnel.
- (g) Provide additional oversight during inspections.
- (h) Apply more stringent severity classifications.
- (i) Decrease the distance between indirect inspection measurements.

5 DIRECT EXAMINATION STEP

- (a) Objectives. The objectives of the direct examination step in the ECDA process are to prioritize indirect inspection indications, select excavation sites, and evaluate the pipeline and its surrounding environment to assess corrosion activity.
- (b) Outline of direct examination step. The direct examination step is typically comprised of the following activities.
 - (1) Prioritizing classified indications.
 - (2) Determining the number of excavations.
 - (3) Collecting data.
 - (4) Evaluating the remaining strength in pipe wall.
 - (5) Performing root-cause analysis, if applicable.
 - (6) Mitigating or planning mitigation of deficiencies.
 - (7) Performing in-process evaluation.
 - (8) Reclassifying and reprioritizing indications, if applicable.

5.1 *Prioritizing classified indications.*

- (a) Prioritizing classified indications is the process of evaluating whether or not to perform a direct examination of an indirect inspection indication. NACE 5.2.1 requires operators to establish criteria to prioritize indications. Table 5.3.5 of GTI-04/0071, "External Corrosion Direct Assessment (ECDA) Implementation Protocol" and NACE Table 4 provide example criteria for the prioritization of indirect inspection indications.
- (b) The following should be considered when setting prioritization criteria.
 - (1) Region's history of prior corrosion.
 - (2) Indirect inspection data.
 - (i) Type of tool used.
 - (ii) Number of tools used.
 - (iii) Alignment of indications.
 - (iv) Classification of indications (e.g., severe, moderate, minor).
 - (3) Encroachments.
 - (4) Foreign line crossings.
 - (5) Physical characteristics of ECDA region under year-round conditions expected to be

- encountered.
- (6) Other unique conditions deemed applicable (e.g., coating condition).
 - (c) At a minimum, NACE 5.2.2 requires indications be prioritized as one of the following categories.
 - (1) Immediate action required. This priority includes indications that:
 - (i) Are likely to have ongoing corrosion activity, and,
 - (ii) When coupled with knowledge of prior corrosion, pose an immediate threat to the pipeline under normal operating conditions.
 - (2) Scheduled action required. This priority includes indications that:
 - (i) May have ongoing corrosion activity, but that,
 - (ii) When coupled with prior corrosion history (or knowledge), do not pose an immediate threat to the pipeline under normal operating conditions.
 - (3) Suitable for monitoring. This priority includes indications considered inactive or having the lowest likelihood of prior or ongoing corrosion activity.
 - (d) An operator may assign indications in a more conservative (higher priority) category (e.g., schedule to immediate) based on knowledge of the pipeline. For example, the operator may choose to define a single indication as "immediate" if the indication is associated with a foreign crossing on a newly acquired pipeline.

5.2 Determining the number of direct examinations.

- (a) Factors. The following factors determine the minimum number of direct examinations required.
 - (1) Location and number of HCAs.
 - (2) Location and number of ECDA regions.
 - (3) Number and priority of indications (e.g., immediate, scheduled, monitored).
 - (4) First-time application of ECDA.
 - (5) Required process validation (i.e., validation digs).
- (b) HCA considerations. In determining the number of direct examinations, the requirements of NACE 5.3 may be combined with the requirement of §192.925(b)(3)(i). For example, an operator may choose to perform one or more additional direct examination(s) to meet the requirements for first-time application of ECDA on a covered segment.
- (c) No indications. When there are no indications identified during the application of the ECDA, NACE 5.3.1.1 requires the operator to determine the ECDA region most susceptible to external corrosion from information derived in the pre-assessment step and select an excavation site within that region to perform this direct examination. The following factors from the pre-assessment step should be considered to determine which ECDA region is most susceptible to external corrosion.
 - (1) Soil resistivity.
 - (2) Soil pH.
 - (3) Leak history.
 - (4) Coating.
 - (5) Drainage.
 - (6) Corrosion control history.
 - (7) Other characteristics listed in 3.4 above.
- (d) Tables and examples. Tables 192.925ii through 192.925vi and Figure 192.925A can be used to assist in understanding the required number of direct examinations. Each set of examples illustrates different indications and regions as listed for first time and subsequent ECDA applications. In accordance with 5.2(b) above, an operator may choose to perform additional digs above the required minimum to comply with the requirements of 192.925(b)(3)(i).

NUMBER OF DIRECT EXAMINATIONS REQUIRED BY NACE SP0502 When ECDA is Being Applied for the First Time in the Segment			
With Identified Indications			No Identified Indications
Immediate Action	Scheduled Action	Monitoring	
All indications that are prioritized as immediate require direct examination. (NACE ¹ 5.3.2.1)	If an ECDA region contains scheduled indications, then perform direct excavations on the 2 most severe scheduled indications in each region. If only 1 scheduled indication exists, then examine a monitored indication. If a monitored indication does not exist, examine an indication most likely for corrosion. (NACE ¹ 5.3.3.2 and 5.3.3.2.1)	If an ECDA region contains only monitored indications (i.e., no immediate or scheduled indications), 2 direct excavations are required at the indications most likely to have corrosion. (NACE ¹ 5.3.4.2 and 5.3.4.2.1)	In the region identified as most likely for corrosion, from the Pre-Assessment Step, perform at least 2 direct excavations at locations identified as the most likely to have corrosion. (NACE ¹ 5.3.1.1 and 5.3.1.1.1)
For indications that were reprioritized from immediate to scheduled, follow the scheduled guidelines in the next column. (NACE ¹ 5.3.2.2)			
	If the results of the direct examination at a scheduled indication show corrosion that is deeper than 20% of the original wall thickness and that is deeper or more severe than at an immediate indication, then do at least 2 more direct examinations (i.e., the indications with next highest priority). (NACE ¹ 5.3.3.3 and 5.3.3.3.1)		
Process Validation Dig: Perform at least 2 additional direct examinations on the pipeline segment (NACE ¹ 6.7.2.1). The direct examinations shall be conducted at randomly selected locations, one of which is categorized as scheduled (or monitored if no scheduled indications exist) and one in an area where no indication was detected. These digs must occur within an HCA.			
¹ All NACE references are to paragraphs in NACE SP0502-2010.			

TABLE 192.925ii

NUMBER OF DIRECT EXAMINATIONS REQUIRED BY NACE SP0502 When ECDA is Being Applied a Second or Subsequent Time on the Segment			
With Identified Indications			No Identified Indications
Immediate Action	Scheduled Action	Monitoring	
All indications that are prioritized as immediate require direct examination. (NACE ¹ 5.3.2.1)	If an ECDA region contains scheduled indications, then perform 1 excavation on the most severe scheduled indication in the region. (NACE ¹ 5.3.3.2)	If an ECDA region contains only monitored indications (i.e., no immediate or scheduled indications), 1 excavation is required at the indication most likely to have corrosion. (NACE ¹ 5.3.4.2)	In the region identified as most likely for corrosion, Pre-Assessment Step, perform at least 1 excavation at the location identified as the most likely to have corrosion. (NACE ¹ 5.3.1.1)
For indications that were reprioritized from immediate to scheduled, follow the scheduled guidelines in the next column. (NACE ¹ 5.3.2.2)	If the results of the direct examination at a scheduled indication show corrosion that is deeper than 20% of the original wall thickness and that is deeper or more severe than at an immediate indication, then perform at least 1 more direct examination (i.e., the indication with next highest priority). (NACE ¹ 5.3.3.3)		
Process Validation Dig: Perform at least 1 additional direct examination at a random location within an HCA where no indications were detected in only one region in the segment (NACE 6.7.2).			
¹ All NACE references are to paragraphs in NACE SP0502-2010.			

TABLE 192.925iii

Following are three examples where a pipeline segment contains two HCAs (HCA 1 and HCA 2). There are two ECDA regions (R1 and R2) with Region 2 being the most likely to have corrosion. In these examples, no corrosion defects are found that are deeper than 20% of the original wall thickness and that are deeper or more severe than at an immediate indication (NACE 5.3.3.3). These examples assume that the results of the direct examinations do not require the need to reprioritize the severity classification (NACE 6.5).

Indirect inspections were conducted over the HCAs. The examples note the number of indications as a result of integrating the inspection data.

Example 1 is a pipeline segment with no indications.

Example 2 is a pipeline segment with scheduled and monitored indications but no immediate indications.

Example 3 is a pipeline segment with immediate, scheduled, and monitored indications.

DIAGRAM FOR EXAMPLES 1 THROUGH 3
Pipe Segment showing 2 HCAs and 2 Regions

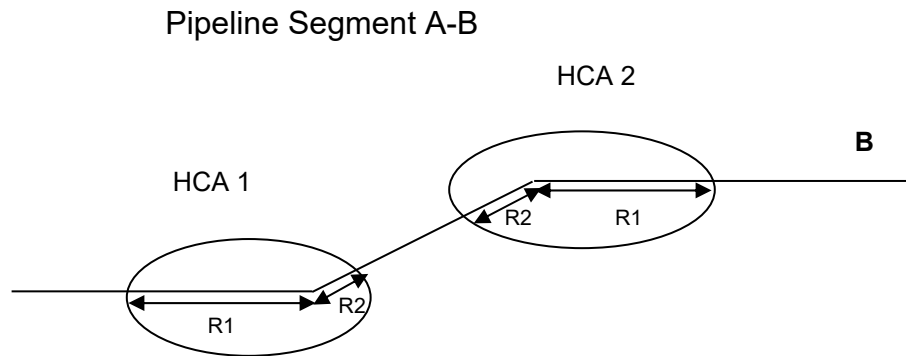


FIGURE 192.925A

The following three tables show the number of direct examinations necessary to meet the requirements of §192.925 and NACE SP0502 for each example.

EXAMPLE 1: PIPELINE SEGMENT WITH NO INDICATIONS															
Number of Indications					Number of Direct Examinations							Additional Examinations for First-Time ECDA			Total Examinations (First Time)
Priority	HCA 1		HCA 2		Priority	Step 3 Direct Exam				Step 4 Validation	Total	Step 3	Step 4	Total Additional	
	R1	R2	R1	R2		HCA 1		HCA 2		Any HCA					
						R1	R2	R1	R2	Any Region		R2 Any HCA	Any Region Any HCA		
I	0	0	0	0	I	0	0	0	0	0	0	0	0	0	0
S	0	0	0	0	S	0	0	0	0	0	0	0	0	0	0
M	0	0	0	0	M	0	0	0	0	0	0	0	0	0	0
					NI	0	^{1A}	0	0	^{1B}	2	^{1C}	^{1D}	2	4
					Total Examinations (If not first time)							2	Total Additional		2

Priority Legend:
 I = Immediate
 S = Scheduled
 M = Monitored
 NI = No Indications

^A If there are no indications, NACE ¹ 5.3.1.1 requires 1 excavation in the region identified as most likely for corrosion (for this example R2 was chosen).
^B For process validation, NACE ¹ 6.7.2 requires a second dig, which can be in any region or any HCA.
^C For first-time ECDA, NACE ¹ 5.3.1.1.1 requires an additional dig in R2, and
^D NACE ¹ 6.7.2.1 requires an additional validation dig which can be in any region.

¹ All NACE references are to paragraphs in NACE SP0502-2010.

TABLE 192.925iv

EXAMPLE 2: PIPELINE SEGMENT WITH SCHEDULED AND MONITORED INDICATIONS (NO IMMEDIATE INDICATIONS)																
Number of Indications					Number of Direct Examinations							Additional Examinations for First-Time ECDA				Total Examinations (First Time)
Priority	HCA 1		HCA 2		Priority	Step 3 Direct Exam				Step 4 Validation	Total	Step 3	Step 3	Step 4	Total Additional	
	R1	R2	R1	R2		HCA 1		HCA 2		Any HCA		HCA 1	HCA 2	Any HCA		
						R1	R2	R1	R2	Any Region		R1	R2			
I	0	0	0	0	I	0	0	0	0	0	0	0	0	0	0	0
S	2	4	1	2	S	0	1 ^A	1 ^A	0	0	2	1 ^C	1 ^C	1 ^D	3	5
M	6	9	7	9	M	0	0	0	0	0	0	0	0	0	0	0
					NI	0	0	0	0	1 ^B	1	0	0	0	0	1
					Total Examinations (If not first time)					3	Total Additional			3	6	

Priority Legend:
 I = Immediate
 S = Scheduled
 M = Monitored
 NI = No Indications

^A Identifies the most severe scheduled indication in the Region. NACE ¹ 5.3.3.2 requires that the most severe scheduled indication in each region be examined.

^B For process validation, NACE ¹ 6.7.2 requires a dig in a randomly selected location, which can be in any region within any HCA.

^C For first-time ECDA, NACE ¹ 5.3.3.2.1 requires an additional examination of the next most severe scheduled indication in each region. If no other scheduled indications exist, then an additional monitored indication shall be examined. If no monitored indications exist, then examine an indication which has a likelihood for corrosion.

^D NACE ¹ 6.7.2.1 requires a second validation dig.

¹ All NACE references are to paragraphs in NACE SP0502-2010.

TABLE 192.925v

EXAMPLE 3: PIPELINE SEGMENT WITH IMMEDIATE, SCHEDULED, AND MONITORED INDICATIONS																
Number of Indications					Number of Direct Examinations						Additional Examinations for First-Time ECDA				Total Examinations (First Time)	
Priority	HCA 1		HCA 2		Priority	Step 3 Direct Exam				Total	Step 3	Step 3	Step 4	Total Additional		
	R1	R2	R1	R2		HCA 1		HCA 2			Any HCA	HCA 1	HCA 2			Any HCA
						R1	R2	R1	R2		Any Region	R1	R2			
I	2	0	1	1	I	2	0	1	1	0	4 ^A	0	0	0	0	4
S	2	4	1	2	S	0	1 ^B	1 ^B	0	0	2	1 ^C	1 ^C	1 ^D	3	5
M	6	9	7	9	M	0	0	0	0	0	0	0	0	0	0	0
					NI	0	0	0	0	1 ^E	1	0	0	0	0	1
					Total Examinations (If not first time)					7	Total Additional			3	10	

Priority Legend:
 I = Immediate
 S = Scheduled
 M = Monitored
 NI = No Indications

^A All immediate indications need to be excavated. (NACE ¹ 5.3.2.1)
^B Identify and excavate the most severe scheduled indication in each Region. (NACE ¹ 5.3.3.2)
^C For first-time application, identify and excavate the next most severe scheduled indication in each Region. (NACE ¹ 5.3.3.3.1)
^D For first-time application, NACE ¹ 6.7.2.1 requires an excavation at a scheduled indication (or monitored if no scheduled indications exist).
^E NACE ¹ 6.7.2.1 requires a validation dig at a randomly selected location where no indication was detected, which can be in any region within any HCA.

¹ All NACE references are to paragraphs in NACE SP0502-2010.

TABLE 192.925vi

- (e) Examination of entire segment. NACE 3.4.1.3 allows the operator to substitute a 100% direct examination in lieu of indirect inspections as long as the inspections and tests required during the direct examination step are performed. The pre-assessment and post-assessment steps must be followed.
- (f) Excavation scheduling. Direct examinations should be conducted as soon as practical to meet the requirements of the following.
 - (1) Completing the Baseline Assessment Plan (BAP) as required by §192.921(d),
 - (2) Discovering conditions that present a potential threat to pipeline integrity as required by §192.933(a) and (b), and

- (3) Meeting the reassessment timeframe as required by §192.939.
- (g) Excavation planning. When planning excavations, the following should be considered.
 - (1) Number and location (e.g., GPS coordinates, specific dimensional location) of excavations.
 - (2) Length, width, and depth of each excavation (based on pre-assessment and indirect inspection data and analysis).
 - (3) Coordination with other excavations, such as excavations for Internal Corrosion Direct Assessment (ICDA).
 - (4) Proposed schedule (order) of digs with contingencies for weather and other delays.
 - (5) Criteria or reasoning for the order of excavations (e.g., prioritized indications).
 - (6) Permits (e.g., local, state, federal).
 - (7) Public communication plan.
 - (8) One-call notification.
 - (9) Environmental and safety procedures.
 - (10) Resource scheduling for the following.
 - (i) Pressure reduction.
 - (ii) Gas flow modifications.
 - (iii) Excavations.
 - (iv) Coating removal.
 - (v) Surface preparation.
 - (vi) Repairs.
 - (vii) Recoating.
 - (viii) Other mitigation efforts.
 - (ix) Other supply issues.
- (h) Scheduling delays. When excavations are delayed, the operator should perform the following.
 - (1) Demonstrate continuing efforts toward completion.
 - (2) Document the reasons for the delays, which might include the following.
 - (i) Seasonal conditions (e.g., frozen ground).
 - (ii) Permitting.
 - (iii) Weather.
 - (iv) Supply interruptions.
 - (3) Take additional precautions, if necessary, to ensure pipeline integrity until the direct examinations can be accomplished. Examples of precautions might include the following.
 - (i) Reduce pressure.
 - (ii) Increase leak surveys.
 - (iii) Increase patrols.

5.3 Data collection.

- (a) Minimum requirements. Before conducting excavations, NACE 5.3.2 requires the operator to define minimum requirements for consistent data collection and recordkeeping at each excavation. When establishing the minimum requirements, the operator is required to address the following unless an alternative method is documented.
 - (1) *Conditions to be encountered.* Knowing the conditions to be encountered at the excavation site should assist the operator in preparation for data collection. Examples of such conditions include the following.
 - (i) Severity of indications (e.g., immediate versus schedule).
 - (ii) Soil conditions (e.g., wet versus dry).
 - (iii) Size of excavation (e.g., key hole versus bellhole).
 - (2) *Types of corrosion activity expected.* An operator should consider increasing data collection when an ECDA region contains several immediate indications compared with an ECDA region with no immediate indications.
 - (3) *Availability and quality of prior data.* An operator should consider collecting additional data at the excavation when data does not exist for the pipeline or certain pre-assessment data is suspect.

- (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, jeepling).
 - (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).

- (d) Remediation.
- (1) If repair and recoating or replacement is performed, the indication is no longer a threat to the pipeline and may be removed from further consideration after completion of the root-cause analysis and the required mitigation activities.
 - (2) If remediation is performed other than that in paragraph (a) (e.g., increase in cathodic protection current), an indication that was initially placed in the immediate or scheduled priority category may be moved to the scheduled or monitored priority category, respectively, provided subsequent indirect inspections justify reducing the indication severity.
 - (3) If corrosion is found on a covered pipeline segment that could adversely affect the integrity of the line, §192.917(e)(5) requires the operator to evaluate and remediate, as necessary, all transmission pipeline segments (both covered and non-covered) having similar material coating and environmental characteristics.
 - (4) For non-covered segments, the operator should establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's O&M procedures for testing and repair of facilities under Part 192.

5.8 *First-time application.*

When applying ECDA for the first time, §192.925(b)(3) and NACE SP0502 require the operator to provide more stringent direct examination criteria than what is required for subsequent assessments. Provision for the more stringent criteria is required to be documented in the ECDA plan. Examples of more stringent criteria for the direct examination step include the following.

- (a) Performing additional direct examinations.
- (b) Performing a larger excavation to inspect nearby indications.
- (c) Performing additional NDE testing (e.g., magnetic particle, radiographic, ultrasonic inspection) on suspected indications or welds.
- (d) Performing additional sampling such as measuring soil resistivity or measuring AC potentials.
- (e) Resurveying the ECDA region after immediate indications are repaired, to determine if other indications were masked by the large indication.

6 POST-ASSESSMENT

- (a) Objectives. The objective of the post-assessment step is to define reassessment intervals and assess the overall effectiveness of the ECDA process. See NACE 6.1.1.
- (b) Reassessment interval. As stated in NACE 6.1.3, the conservatism of the reassessment interval is not easy to quantify because there are uncertainties in the estimates or measurements of remaining flaw sizes, maximum corrosion rates, and the periods of a year in which defects grow by corrosion. To account for these uncertainties, the assessment interval calculated during the Post-Assessment Step is based on a half-life concept. Conservative growth rates are to be combined with estimated remaining flaw sizes to calculate the true life of the defect. The reassessment interval is then set at the lower half of that value or the maximum allowed reassessment interval.
- (c) Outline of post-assessment step. The post-assessment step is broken down into five activities as follows.
 - (1) Remaining flaw size estimation.
 - (2) Corrosion growth rate calculation.
 - (3) Remaining life and reassessment interval calculation.
 - (4) Assessment of ECDA effectiveness.
 - (5) Feedback (continuous improvement).

6.1 *Remaining flaw size estimation.*

- (a) If no corrosion defects are found, then the remaining life is the same as a new pipe.
- (b) It is required to use the most severe, non-unique external corrosion defect that is found during direct examinations of all indications to determine the remaining life for all "scheduled" indications not excavated (NACE 6.2). The most severe external corrosion may not necessarily be the one with the deepest pit but the one that results in the lowest failure pressure. The root-cause analysis determines which defects are unique (e.g., corrosion from a known stray current source, third-party damage at a foreign line crossing) and which are non-unique (e.g., insufficient cathodic protection).
- (c) As an alternative, a pipeline operator may substitute a different flaw size value based on a statistical or more sophisticated analysis of the excavated severities. In addition, an operator may use pre-assessment defect information from maintenance and operation excavations to improve the estimate of the maximum remaining flaw size.

6.2 *Corrosion growth rate calculation.*

- (a) The corrosion growth rate is required to be based on a sound engineering analysis (NACE 6.2.3). If available, an operator should use actual corrosion rate information for the region. Actual corrosion rates may be determined by direct measurement of wall thickness as a function of time on the pipeline in question. An operator should review data collected in the pre-assessment records to determine if this information is available. For example, an operator has a recent measurement of pipe wall loss (e.g., from direct examination). The wall loss divided by the number of years the pipeline has been in service may provide an adequate corrosion rate.
- (b) If actual corrosion rate data on the pipeline region is not available, NACE Appendix D provides guidance on other methods to estimate corrosion rates. Appendix D provides a default corrosion pitting rate of 16 mils per year (mpy) (1mil = 0.001 inch) when other data is unavailable. The 16 mpy rate can be reduced to 12 mpy if it can be shown that the CP levels of the effected pipeline regions had at least 40 mV of polarization (considering IR drop) since installation (NACE D3.3).
- (c) Acceptable alternatives to estimate the corrosion rate are referenced in NACE Appendix D. This Appendix provides information on various analytical techniques such as corrosion coupon analysis, linear polarization resistance measurement, and electrical resistance probes. It also discusses the various soil and environmental factors that affect corrosion rates.

6.3 *Remaining life and reassessment interval calculation.*

- (a) NACE 6.2.4 requires the operator to use sound engineering analysis to estimate the remaining life of the maximum remaining flaw. The operator may use the formula provided in NACE 6.2.4.1 or the following equivalent equation.

Remaining Life Equation:

$$RL = \frac{0.85}{\text{yield pressure}} \times ((P_f - MAOP) \frac{t}{CR})$$

Where:

- RL* = Remaining life, years
- P_f* = Burst pressure RSTRENG, psig
- MAOP* = Maximum allowable operating pressure, psig
- t* = Wall thickness, inches
- CR* = Corrosion rate, inches/year
- yield pressure* = $\frac{(2)(SMYS)(t)}{D}$
- SMYS* = Specified minimum yield strength, psi
- D* = Outside diameter, inches

- (b) When corrosion defects are found during the direct examinations, the maximum reassessment interval for each ECDA region shall be taken as one-half the calculated remaining life (NACE 6.3.1). The reassessment interval is then set at the lower of half of that value or the maximum allowed reassessment interval.

Example: A pipeline operates at a hoop stress of 25%. A half-life analysis in accordance with NACE calculates to be 23 years. In accordance with §192.939 (b)(6), the maximum reassessment interval is 20 years. Therefore, the required reassessment interval for a full integrity assessment is 20 years. Note that either confirmatory direct assessment is required every 7 years or the requirements of a low stress reassessment per §192.941 should be followed.

- (c) Section 192.925(b)(4)(ii) requires that an operator provide criteria to evaluate whether a covered segment needs to be reassessed at an interval shorter than specified in §192.939. The following are examples of criteria.
- (1) History of corrosion leaks.
 - (2) Unexpected unique defects.
 - (3) High number of scheduled indications remain unexcavated.
 - (4) Half-life calculation is less than maximum allowed interval.
- (d) NACE 6.3.3 requires that any indications scheduled for evaluation should be addressed before the end of the reassessment interval. Examples of addressing scheduled indications at the location prior to the next reassessment interval include the following.
- (1) Annual pipe-to-soil potential.
 - (2) Annual coating evaluation (e.g., DCVG).
 - (3) More frequent leak survey.
 - (4) More frequent patrol.
 - (5) Annual review of O&M records.
 - (6) Confirmatory direct assessment.
 - (7) Direct examination.
 - (8) Pipe replacement.

6.4 Assessment of ECDA effectiveness.

- (a) Upon subsequent applications of the ECDA process, if it is determined that there is more severe corrosion than expected (calculated), then the process is required to be reevaluated and repeated or an alternative integrity assessment method used (NACE 6.4.2.2).
- (b) NACE 6.4.3 requires the operator to establish criteria to assess the long-term effectiveness of the ECDA process. Assessing effectiveness may be performed by establishing and tracking performance measures. Examples of ECDA performance measures include the following.
- (1) Reliability and repeatability.
 - (i) Track number of reclassifications.
 - (ii) Track number reprioritizations.
 - (2) Application.
 - (i) Track number of excavations.
 - (ii) Track number of repairs.
 - (iii) Track number of miles (footage) inspected.
 - (iv) Track number of miles (footage) for which each inspection tool was used.
 - (3) Comparing prior results to results of subsequent reassessments. Examples include the number of the following.
 - (i) Reclassifications.
 - (ii) Reprioritizations.
 - (iii) Immediate actions.
 - (iv) Scheduled actions.
 - (v) Monitored actions.

- (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 listing in §192.7, not IBR for §192.925).
- (b) ASME B31G, "Manual for Determining the Remaining Strength of Corroded Pipelines." (see listing in §192.7, not IBR for §192.925).
- (c) NACE SP0502-2010, "Pipeline External Corrosion Direct Assessment Methodology." (see §192.7 for IBR).
- (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 CO₂, O₂, hydrogen sulfide or other contaminants present in the gas.

(b) **General requirements.** An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in 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 —

(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.

[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

This guide material is under review following Amendment 192-132.

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 §§192.18, 192.921, and 192.937.
- (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)

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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 ₂ S 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)

INFORMATION FOR ICDA (Continued)		
Data Element	ICDA Influence	Key Decision Points & Comments
Internal corrosion treatments	The effectiveness of treatments may not be uniform along a pipeline.	Corrosion treatments (e.g., biocides or corrosion inhibitors) may not be evenly dispersed throughout the pipeline. For example, the treatment might inhibit corrosion at the first low point, but not at points farther downstream. If internal corrosion inhibitors are used, the operator may need to conduct additional examinations or verify whether the treatment is effective throughout the ICDA region.

TABLE 192.927i

- (d) Subject Matter Experts (SMEs) may be used to gather and evaluate operating experience data that would provide additional information regarding low points and historic upsets in gas conditions, locations where these low points or upsets have occurred, and any evidence of corrosion damage resulting from low points or upset conditions.

3.2 ICDA feasibility.

Data and information collected must be integrated and evaluated to determine the feasibility of using ICDA on covered segments (§192.927(c)(1)). If sufficient data is not available or cannot be collected for an ICDA region to support the pre-assessment step, ICDA may not be feasible.

The following are examples of criteria used in determining that ICDA is not feasible.

- (a) Key data, such as inside diameter and gas velocity, are not available or reasonable assumptions cannot be made.
- (b) A pipeline that normally contains an electrolyte in the gas stream (i.e., a wet-gas system).
- (c) A pipeline that has been previously converted from transporting other products (e.g., crude oil, refined products) unless it is demonstrated either that internal corrosion did not occur in the previous service or that previous damage has been separately assessed.
- (d) A pipeline with a history of pigging that could distribute liquids in a way that is not predicted by ICDA. The operator should provide technical justification whenever ICDA is applied to a pipeline that has a history of using cleaning pigs. An example would be lines with liquids that do not contain an electrolyte (e.g., drip gas).
- (e) A pipeline treated with corrosion inhibitors. The use of inhibitor may preclude application of ICDA because the effectiveness of the inhibitor might not be uniform along the pipeline length.
- (f) The pipeline has an internal coating that is intended to provide corrosion protection. The use of internal coating may preclude application of ICDA because the effectiveness of the coating might not be uniform along the pipeline length.
- (g) Pipelines that contain accumulations of solids, sludge, biofilm/biomass, or scale. Such accumulations may affect the validity of this ICDA process. See NACE SP0206, Paragraph 3.3.7.

4 IDENTIFICATION OF ICDA REGIONS

- (a) An ICDA region is a defined length of a pipeline that begins at the location where a liquid containing an electrolyte may first enter the pipeline. Examples of beginnings include the following.
 - (1) Delivery point or take station.
 - (2) Production well.
 - (3) Connection with another pipeline.
 - (4) Storage well.

- (b) In accordance with §192.927(c)(2), an ICDA region encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. In accordance with the model in GRI-02/0057, the critical angle determines the extent where the corrosion will occur. Thus, an ICDA region begins at an input point and ends where the first pipeline inclination angle exceeds the critical angle.
- (c) In a pipeline where bi-directional flow exists or has existed and where electrolytes are present in the gas from both source locations, it is required to consider each flow direction when determining the ICDA regions (see GRI-02/0057).
- (d) In accordance with §192.927(c)(2), an operator's ICDA plan must identify all ICDA regions. An ICDA region may encompass one or more covered segments.

5 IDENTIFICATION OF LOCATIONS FOR EXCAVATION AND DIRECT EXAMINATION

The identification of excavation locations is based on the following.

- (a) Flow-modeling to determine the critical angle.
- (b) Developing a pipeline elevation profile.
- (c) Identifying sites where internal corrosion may likely occur.

Direct examination is then conducted in order to assess the internal surface of the pipeline for corrosion. If corrosion is found, evaluations of remaining strength in the pipe wall and mitigation are required (§192.927(c)(3)(i)).

5.1 *Critical angle determination.*

- (a) The critical angle is defined as the smallest angle determined by dry gas ICDA flow modeling at which liquid carryover will not occur under stratified flow conditions. In accordance with §192.927(c)(2), an operator is required to use the model as defined in GRI-02/0057, or an equivalent model, to determine the critical angle for each ICDA region that includes a covered segment. See NACE SP0206 ICDA for an example of an equivalent model.
- (b) To calculate the critical angle using the model contained in GRI-02/0057, the operator needs to determine the following information (§192.927(c)(2)).
 - (1) Inside diameter.
 - (2) Gas temperature.
 - (3) Operating pressure.
 - (4) Liquid density.
 - (5) Gas density.
 - (6) Gas velocity.
- (c) Where pipeline operating conditions fluctuate (e.g., pressure, temperature, or flow direction), the operator should consider calculating multiple angles for the appropriate fluctuating conditions to determine if the location of the critical angle changes.

5.2 *Pipeline profile.*

- (a) The pipeline profile reflects elevation changes along the pipeline.
- (b) Data used in determining a pipeline profile may include the following.
 - (1) *Surface elevations.*

Surface elevations may be obtained from the following.

 - (i) Elevation survey of the land over the pipeline.
 - (ii) Land-base data such as topographic maps.

Elevation measurements should be taken at intervals that capture relevant changes in the surface profile. The minimum interval depends upon the specific pipeline being evaluated, the terrain, and other features. The intervals at known pipe route obstructions (e.g., roadways, rivers) should be decreased in order to capture specific pipeline fittings (e.g., vertical elbows, pipe bends).

(2) *Depth of cover.*

An operator should determine depth of cover, which can be determined by the following.

- (i) Using average depth of cover considering possible changes based on construction records and inspection reports.
- (ii) Performing a depth-of-cover survey.

(c) *Determining profile.*

Subtracting the depth-of-cover data from the surface elevation determines the pipeline profile. The degree of accuracy required in the calculation of the pipeline profile is relative to the critical angle size. For very small critical angles (e.g., 1 degree) the operator should consider increasing the precision of the pipeline profile. Methods to increase the precision include the following.

- (1) Using more accurate elevation measurement techniques.
- (2) Using survey-grade GPS for stationing.
- (3) Decreasing the spacing between elevation survey measurement points.
- (4) Potholing to measure the depth of the pipeline.
- (5) Using an instrument (e.g., current attenuation) to determine the depth of cover.

5.3 *Pipeline inclination angle.*

The pipeline inclination angle is the angle (measured in degrees) resulting from an increase in elevation between two pipeline profile data points. It is calculated using the following equation.

$$\theta_i = \arcsin\left(\frac{\Delta(\text{elevation})}{\Delta(\text{distance})}\right)$$

Where:

- θ_i = Angle in degrees
- $\Delta(\text{elevation})$ = Elevation change, feet
- $\Delta(\text{distance})$ = Distance change, feet

These pipeline inclination angles shall be established between the profile data points along the length of each identified ICDA region (§192.927(c)(2)). If bi-directional flow exists or has existed within the pipeline, the critical angle needs to be calculated for both directions and compared to the pipeline inclination angles for the appropriate direction. If the first critical angle is upstream of each involved covered segment, ICDA may be discontinued.

5.4 *Identifying excavation location.*

The operator is only required to dig and directly examine within a covered segment (§192.927(c)(3)), the location of which can be found by the following.

- (a) Comparing the critical angle with the pipeline inclination angles.
- (b) Determining the first critical angle location downstream from beginning of the ICDA region.
- (c) Determining the location(s) of the covered segments relative to the first critical angle.
- (d) Perform excavations at the following locations.
 - (1) The low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA region.
 - (2) A second location further downstream, within a covered segment, near the end of the ICDA region. If all pipe inclinations have angles smaller than critical, the operator should choose the angle of greatest inclination within the covered segment.
- (e) If the ICDA region ends before the start of the covered segment (pipeline inclination angle that exceeds critical angle is upstream of covered segment), the first two steps of the ICDA process can be used as a threat screening tool. Since the covered segment is downstream of a critical angle, electrolytes will not reach the covered segment and internal corrosion is not a threat to the covered segment. If there is bidirectional flow, both flow directions must be considered before determining the applicability of internal corrosion as a threat (§192.927(c)(1)(ii) and (iii)).

- (f) Examples are provided in 5.5 below to show the relationship between ICDA regions, covered segments, and proposed excavation locations.

5.5 Examples.

- (a) Example 1 — Covered Segment Downstream of Critical Angle.

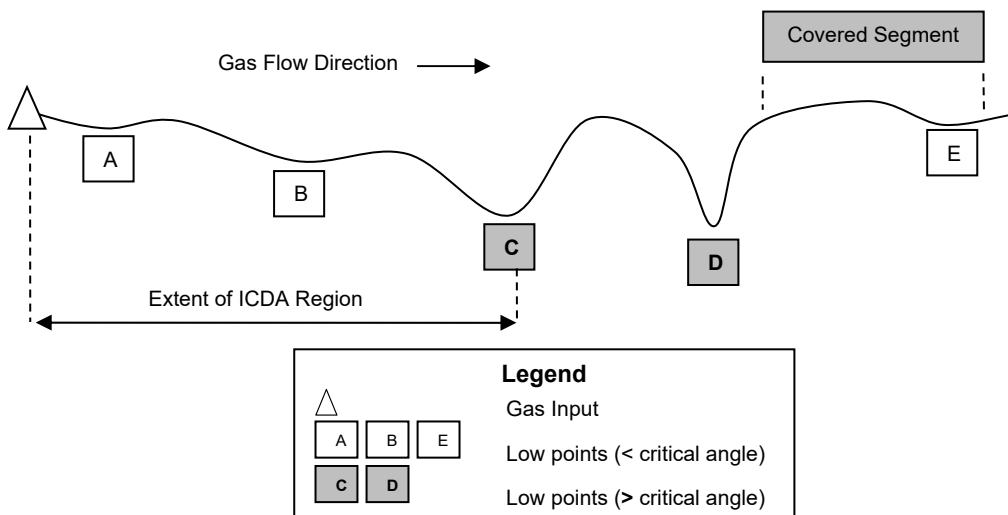


FIGURE 192.927A

Figure 192.927A illustrates a pipe inclination angle greater than the critical angle that is located upstream of the covered segment. Note that the ICDA region ends at the critical angle because §192.927(c)(2) states the region extends along the area where corrosion may occur. In this example, the threat of internal corrosion can be ruled out downstream from Point "C" if there are no other inputs; thus, the ICDA integrity assessment can stop. The operator should continue to monitor the operating parameters of the system to determine if the critical angle or pipe inclination angle changes.

- (b) Example 2 — Covered Segment Includes Critical Angle.

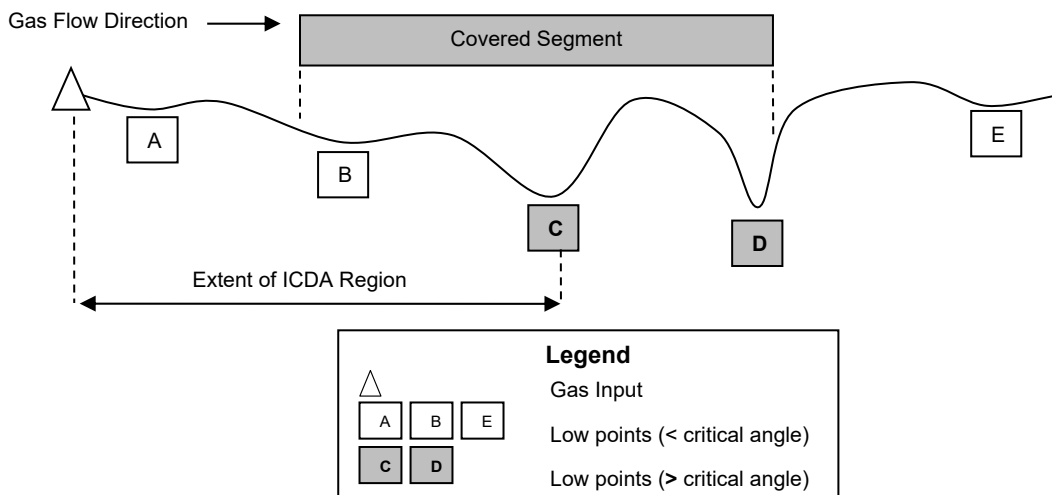
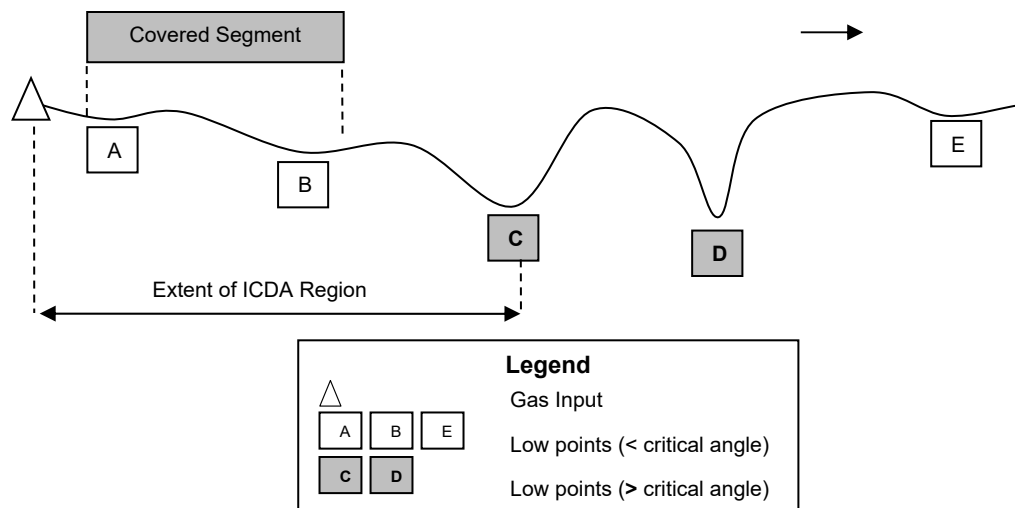


FIGURE 192.927B

- (1) Figure 192.927B illustrates a scenario where the first pipe inclination angle greater than critical angle (Point "C") is located within the covered segment and ICDA region. Point "B" is required to be excavated because it is the first low point near the beginning of the covered segment. Point "C" is required to be excavated because it is within the covered segment, near the end of the ICDA region, and at a location where the inclination angle is greater than critical angle (see §192.927(c)(3)).
 - (2) If no corrosion is found at Points "B" and "C," then internal corrosion is not a threat to the covered segment. The operator should continue to monitor the operating parameters of the system to determine if any pipe inclination angle changes occur due to construction or maintenance activity on the covered segment.
 - (3) If corrosion is found at Point "B" or Point "C," the operator is required (§192.927(c)(4)(ii)) to conduct additional excavations or assess the covered segment by another method. If additional excavations are to be used, the length of the excavations and Point "A" or "B" could be extended to look for additional internal corrosion or another location could be examined. This regulation also requires that if corrosion is found (§192.927(c)(3)(iii)), non-covered segments with the same operating conditions must be evaluated and remediated. To address the non-covered segment, Point "A" should be excavated and examined.
- (c) **Example 3** — Covered Segment Upstream of Critical Angle.



- (1) Figure 192.927C illustrates a pipe inclination angle greater than the critical angle located downstream of the covered segment. Excavations are required at Point "A" (the first upstream low point) and at Point "B" (a second downstream point within the covered segment). If corrosion is not found at either location, then internal corrosion is not a current threat to the covered segment. The operator should continue to monitor the operating parameters of the system to determine if any pipe inclination angle changes occur due to construction or maintenance activity on the covered segment.
- (2) If corrosion is found at Point "A" or Point "B," the operator is required (§192.927(c)(4)(ii)) to conduct additional excavations or assess the covered segment by another method. If additional excavations are to be used, the length of the excavations and Point "A" or "B" could be extended to look for additional internal corrosion, or another location could be examined. This regulation also requires that if corrosion is found (§192.917(e)(5)), non-covered segments with the same operating conditions must be evaluated and remediated. To address the non-covered segment, Point "C" could be excavated and examined.

5.6 Direct examination.

The objective of the ICDA direct examination is to determine if internal corrosion exists at the locations identified in 5.4 above. ICDA required excavations may be used as ECDA validation digs if applicable conditions are analyzed and documented. In addition, ECDA required excavations may be used for ICDA validation digs if the conditions are analyzed and documented.

(a) Determining extent of excavation.

- (1) For a short elevation drop associated with a feature (e.g., a road crossing), water accumulation commonly occurs on the short uphill segment, indicating a limited section of pipe to excavate.
- (2) Where a long, constant up-slope exists, such as a hill or a rise, identification of the liquid holdup location within the section of pipe may be more difficult. It has been shown that in this situation, there is the possibility that the liquid will be pushed up the slope where it will roll back on itself and, as such, may not settle to the bottom of the angle if velocity is maintained. In this case, the operator may consider the use of assessment methods that provide a larger "view" of the situation. For example, a long-range guided wave evaluation may be made from an excavation up the slope from the base of the critical angle so that internal corrosion may be detected from the bottom of the angle, past the test point, and forward up the slope. If internal corrosion is identified, then additional direct examination should be performed at its apparent location with detailed measurements of wall loss made as described in 5.6(b) below.

(b) Metal loss measurements.

- (1) In accordance with §192.927(c)(3), the operator is required to perform a direct examination for internal corrosion using ultrasonic thickness (UT) measurements, radiography, or other generally accepted measurement techniques, such as electromagnetic or guided wave.
- (2) Instruments, such as UT, are used to measure the pipe's wall thickness, which is then compared to the expected wall thickness. Sufficient wall thickness measurements should be taken circumferentially and longitudinally along the pipe. Measurements should be spaced close enough to ensure that an accurate depiction of the inside surface of the pipe has been reasonably determined. For example, an operator could use a 1-inch grid. Decreased spacing should be considered on the bottom portion of the pipeline (e.g., between the 4- and 8- o'clock positions).
- (3) Personnel performing metal loss measurements must be qualified in the measurement technique used (§192.915(b)).
- (4) When performing any direct examination, the same data collection procedures should be followed, whether the driver was ICDA, ECDA, ILI, or simply O&M. (see guide material under §192.925). Specific examples of data to be collected for ICDA include the following.
 - (i) Wall thickness measurements.
 - (ii) Measurement of pipe inclination with a digital level.
 - (iii) Pipe configuration and attributes.
 - (iv) Radiographic reports.
- (5) To determine if corrosion is present, consideration should be given to comparing measurements with the minimum specified tolerance allowed by the applicable pipe specification to which it was manufactured (e.g., API Spec 5L – see listing in §192.7, not IBR for §192.927).

(c) Corrosion found.

Section 192.927(c)(3) requires that, when corrosion is found, the severity of the defect (remaining strength) needs to be evaluated and the defect addressed in accordance with §192.933. The direct examination step should continue with the following activities.

- (1) Determine the remaining strength in the pipe wall.
- (2) Evaluate the cause.
- (3) Mitigate the affected pipe segment.

(d) Remaining strength.

Methods for calculating remaining strength of the pipe are ASME B31G, ASME B31G Modified, PRCI PR-3-805 (RSTRENG), or equivalent methods. The pre-assessment and direct examination steps are sources for data that may be used in the calculation method selected. Examples of data needed for calculating remaining strength include the following.

- (1) SMYS.
- (2) Pipe outside diameter.
- (3) Measured remaining wall thickness.
- (4) Extent of corrosion (e.g., length and depth of pits).

The remaining strength (e.g., burst pressure) is then compared to the MAOP of the pipeline. The comparative results may require an operator to take additional remedial action, such as lowering operating pressure, replacement, or repair of the pipe segment. See 5.2(f) below for additional mitigation guidance.

(e) Evaluation of cause.

An evaluation of the cause of internal corrosion should be performed (see guide material under §192.475). This evaluation may determine the following.

- (1) If ICDA is suitable for finding degradation caused by the presence of a specific internal corrosion mechanism.
- (2) The characteristics of the gas, liquids, and solids that are causing the internal corrosion.
- (3) The possible source and situation that introduced the gas impurities and electrolytes into the system.
- (4) Whether the corrosion is more likely historic or ongoing.
- (5) Recommendations for monitoring and mitigating the possibilities of future electrolyte intrusions and internal corrosion.

Even if corrosion damaged pipe is removed from service, the conditions that caused the damage should be addressed.

(f) Mitigation.

- (1) Replacement or repair should be made with materials and processes that are suitable for the pipeline operating conditions (see §§192.476, 192.487, and 192.713). Any replacement or repair made should be done in conjunction with the mitigation and prevention of internal corrosion (see guide material under §192.476). Unless the corrosion source is mitigated, pipe requiring repair or replacement will require continued monitoring in each covered segment where the internal corrosion has been identified.
- (2) When internal corrosion is found, the operator is required (§192.927(c)(3)(iii)) to evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system. This applies to systems having similar characteristics to the ICDA region containing the covered segment in which corrosion was found. As appropriate, the operator is to remediate the conditions found in accordance with §192.933. Examples of similar characteristics include the following.
 - (i) Source of gas supply.
 - (ii) Pipeline profile.
 - (iii) Liquid collection points, such as drips.
 - (iv) Operating pressure and temperature.
 - (v) Age of pipe.
 - (vi) Dehydration or treating equipment.
 - (vii) Pipe sections subjected to the same hydrostatic pressure test.

6 POST-ASSESSMENT EVALUATION AND MONITORING

The post-assessment evaluation and monitoring step involves the integration and analysis of data collected from the previous three steps to determine the effectiveness of the ICDA process, establish reassessment, and schedule monitoring of covered segments where internal corrosion has been found.

6.1 *Determining ICDA effectiveness.*

The effectiveness of the ICDA process is determined by the correlation between detection and non-detection of corrosion at the location where internal corrosion is predicted to occur. ICDA is also considered to be effective if pipeline history and current operating conditions indicate internal corrosion is not expected and no corrosion is found in the direct examination step. If internal corrosion is found throughout the pipeline (e.g., not at low points), or corrosion is found on top of the pipe, ICDA feasibility should be reevaluated. If corrosion is found downstream of the first critical angle, then the determination of the critical angle should be reevaluated.

6.2 *Determining reassessment intervals.*

In accordance with §192.927(c)(4), the operator is required to determine if the covered segment should be reassessed at more frequent intervals than specified in §192.939. The following process determines reassessment intervals for ICDA (§192.939(a)(3)).

(a) Remaining defect size estimation.

(1) *No corrosion found.* If no corrosion defects are found, then the remaining defect size is zero.

(2) *Corrosion found.* In accordance with §192.939(a)(3)(ii), use the largest remaining corrosion defect to estimate the reassessment interval.

(b) Remaining life determination.

An operator should use sound engineering analysis to estimate the remaining life of the largest remaining defect. If no corrosion defects are found, then the remaining life is the same as new pipe. The operator may use the formula provided in NACE SP0502-2010, Paragraph 6.7.2.1 (see §192.7), or an equivalent equation such as the following.

Remaining Life Equation:

$$RL = \frac{0.85}{\text{yield pressure}} \times ((P_f - MAOP) \frac{t}{CR})$$

Where:

- RL = Remaining life, years
- P_f = Burst pressure RSTRENG, psig
- $MAOP$ = Maximum allowable operating pressure, psig
- t = Wall thickness, inches
- CR = Corrosion rate, inches/year

$$\text{yield pressure} = \frac{(2)(SMYS)(t)}{D}$$

- $SMYS$ = Specified minimum yield strength, psi
- D = Outside diameter, inches

(c) Corrosion rate calculation.

(1) The corrosion growth rate should be based on sound engineering analysis. If available, an operator should use actual corrosion rate information for the ICDA region. Actual corrosion rates may be determined by direct measurement of wall thickness as a function of time for the pipeline in question. An operator should review data collected in the pre-assessment records to determine if this information is available. For example, data may include recent measurement of pipe wall loss (e.g., from direct examination). The wall loss divided by the number of years the pipeline has been in service may provide an adequate corrosion rate.

(2) Acceptable alternatives to estimate the corrosion rate are referenced in NACE SP0206, Paragraph 6.3.1.

(d) Reassessment interval calculation.

(1) When corrosion defects are found during direct examinations, the maximum reassessment interval for each ICDA region is the lower of the following.

- (i) One-half the remaining life, or
- (ii) The reassessment interval allowed in ASME B31.8S, Section 5, Table 3 (see Table 192.939iv of the guide material under §192.939).

Note: For the ICDA process, the meaning of the phrase "sample of indications" as used in ASME B31.8S, Section 5, Table 3 is considered to be the direct examination of the pipe at the first upstream critical angle.

(2) For pipelines operating at 30% or more of SMYS and the ICDA reassessment interval exceeds 7 years according to ASME B31.8S, then Confirmatory Direct Assessment (CDA) or other assessments such as ILI, ICDA, or pressure testing is required to be performed at intervals not exceeding 7 years (§192.939).

(3) For pipelines operating at less than 30% SMYS, a low stress reassessment may be conducted (see guide material under §192.941). Example: A pipeline operates at a hoop stress of 25% SMYS and the half-life analysis calculates to be 23 years. In accordance with §192.939(b)(6), the maximum reassessment interval is 20 years. Therefore, the required reassessment interval for a full integrity assessment is 20 years. Note that either CDA is required every 7 years or the operator is required to follow the requirements of a low stress reassessment in accordance with §192.941.

6.3 Continual monitoring.

(a) In accordance with §192.927(c)(4)(ii), continual monitoring is required for each covered segment where internal corrosion has been identified. Internal corrosion monitoring must meet the requirements of §192.477. Examples of monitoring techniques include the following.

- (1) Use of corrosion coupons.
- (2) Use of electronic probes.
- (3) Use of UT sensors.
- (4) Liquid sampling at low points.
- (5) Review of records such as the following.
 - (i) Leak records.
 - (ii) Gas analysis.
 - (iii) Fluids analysis.
 - (iv) Repairs.
 - (v) Exposed pipe.

(b) If evidence of corrosion products (e.g., pitted corrosion probe, deposits, scale) is found during the monitoring of the covered segment, prompt action is required to be taken to implement at least one of the following actions (§192.927(c)(4)(ii)).

- (1) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe. The operator should perform a direct examination in accordance with 5.6 above. See 5.4 above for identifying the direct examination locations.
- (2) Assess the covered segment using another integrity assessment method allowed by Subpart O.

7 FIRST-TIME ICDA APPLICATION

When conducting ICDA for the first time on a covered segment, more restrictive criteria is required (§192.927(5)(ii)). Examples of more restrictive criteria include the following.

(a) Pre-assessment.

- (1) Analyzing additional data elements (e.g., data not listed in Table 192.927i), such as temperature, or other internal corrosion data defined by the operator.
- (2) Obtaining and analyzing upset information from both suppliers and other upstream operators with the same supplier.

- (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, 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.

Addendum 2, February 2023

Addendum 4, May 2024

(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.

[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

This guide material is under review following Amendment 192-132.

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.

- (f) References.
- (1) For guidance on determining whether SCC is a threat to a covered segment, see 5 of the guide material under §192.917.
 - (2) For guidance on defining SCC and the types and characteristics of SCC, see 4 of the guide material under §192.613.
 - (3) For additional guidance in conducting an integrity assessment for SCC, see the following.
 - (i) NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology." The NACE SCCDA process consists of four steps: pre-assessment, indirect inspections, direct examinations, and post assessment.
 - (ii) ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas." This report is a result of a joint industry project to develop technical rationale supporting the key processes of SCC integrity management. The content includes the following.
 - (A) Defining the basis for SCC susceptibility.
 - (B) Prioritizing HCA segments susceptible to SCC.
 - (C) Selecting the appropriate assessment location and method for each segment.
 - (D) Defining mitigation of SCC when found, and assessing the severity.
 - (E) Determining the reassessment interval.
 - (F) Determining additional preventive and mitigative measures.

3 DATA GATHERING AND INTEGRATION

3.1 Data collection.

Data may be obtained from various sources, including the following.

- (a) Operating and maintenance records.
- (b) Alignment sheets.
- (c) Records of pipeline temperatures downstream of compressor stations (current and historical).
- (d) Risk assessment process.
- (e) SME input.
- (f) Field verification.
- (g) Pressure tests.

3.2 Minimal data.

In accordance with ASME B31.8S, Appendix A3.2, minimal data sets are to be collected as outlined in Table 192.929i below.

MINIMAL DATA SETS		
Data Element	SCC Influence	Key Decision Points & Comments
Age of pipe	Affects the length of time a pipe is exposed to stresses and the environment.	Since the SCC threat is time dependent, the threat may increase the longer the pipe is in service. ASME B31.8S, Appendix A3 states that a segment does not need to be assessed for SCC if the pipe has been in service less than 10 years.

TABLE 192.929i (Continued)

MINIMAL DATA SETS (Continued)		
Data Element	SCC Influence	Key Decision Points & Comments
Operating stress level	A factor in SCC initiation and growth of cracks.	Impacts SCC initiation, critical flaw size, and remaining life predictions. A pipeline operating above 60% SMYS is considered susceptible to high pH SCC. Increases in toughness, which have generally occurred in parallel with increasing SMYS, have significantly increased the size of cracks that can result in failure or leak. See 4 of the guide material under §192.613.
Operating temperature	Relevant to coating degradation and crack formation, particularly for high pH SCC.	<ul style="list-style-type: none"> Higher pipeline temperatures can increase the probability of SCC. ASME B31.8S, Appendix A3 states high pH SCC only needs to be assessed if the pipeline temperature is greater than 100 °F. High pipeline temperatures may be due to compressor discharge, gas from deep wells with higher down-hole temperatures, and long-term underground fires. Temperature may accelerate high pH SCC. Near-neutral pH SCC can occur at temperatures less than 100 °F, so temperature is not a critical factor for near-neutral pH SCC. However, elevated temperatures can contribute to coating disbondment and deterioration. Consideration should be given to the historical operating temperature.
Distance of the segment from a compressor station	Pipe within 20 miles of station has a higher risk of SCC.	A pipeline segment less than 20 miles downstream of a compressor station is more susceptible to high pH SCC because of high discharge temperatures.
Coating type	Certain types of coatings are known to disbond from the pipe. Disbonded coatings may allow the pipe to come into contact with the environment.	<ul style="list-style-type: none"> SCC has not been found on pipe with undamaged FBE or extruded polyethylene coating. High pH SCC has been found under coal tar, asphalt, and tape coatings. Near-neutral pH SCC is most commonly associated with tape coatings, but has also been found under coal tar and asphalt coatings. Records have indicated that approximately ¾ of near-neutral pH SCC occurrences were under tape coatings. The age of the pipe may impact coating degradation and increase susceptibility to SCC. Surface preparation for the coating is an important factor to consider for both near-neutral and high pH SCC. Shot peening or grit blasting appear to be beneficial by removing mill scale, inhibiting crack initiation, and creating compressive residual stresses in the surface of the pipe. Mill scale tends to promote potential for high pH SCC. SCC has been observed on bare pipelines in high resistance soils.

TABLE 192.929i (Continued)

MINIMAL DATA SETS (Continued)		
Data Element	SCC Influence	Key Decision Points & Comments
Past hydrostatic test information for reasons other than SCC investigation	There is a high probability of finding more SCC in the vicinity of previously discovered SCC.	All available reports should be reviewed to determine if SCC has been detected.

TABLE 192.929i

3.3 Other data considerations.

- (a) Soil and terrain. Soil characteristics and drainage, both influenced by topography, may be correlated with near-neutral pH SCC. (See NACE SP0204, Appendix A for additional information.)
- (b) Cathodic protection (CP). CP might play a role in the development of SCC. Areas with low CP readings (<850 mV as referenced to a copper-copper sulfate half cell) tend to be more prone to high pH SCC. High CP readings might lead to possible disbondment of the coating which might lead to more susceptibility of near-neutral pH SCC. Potentials >1200 mV (compensated for IR drop) might need to be investigated.
- (c) Seam type. Near-neutral pH SCC has been found under the following circumstances.
 - (1) In the heat-affected zone of the longitudinal seam of some pre-1970 ERW pipe.
 - (2) Under tented (never bonded) tape coatings in DSA (double submerged arc) welds.
 - (3) In the heat-affected zone of some girth welds.
- (d) Pipe attributes. There is no known correlation between SCC and the grade, diameter, or wall thickness of the pipe. However, this data is needed to determine percent SMYS.
- (e) Cyclic Fatigue. The operator may review historical pressure records to monitor the magnitude and frequency of pressure cycles on a pipeline.
- (f) Pipe inspection reports. Data contained in pipe inspection reports that identify possible SCC.
- (g) Other data. An operator should consider the guide material under §192.613 and NACE SP0204, Table 1 for additional data to gather and integrate.

3.4 Data integration and evaluation.

After collecting applicable data, the operator must evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment (§192.929)(b)(1)).

- (a) During the threat identification for SCC (see §192.917), an operator should have determined if the threat of SCC exists on a covered segment. See 5 of the guide material under §192.917 for additional threat identification guidance and criteria to determine if the conditions for high pH and near-neutral pH SCC are present.

Operators with historical SCC failures in locations that are outside of the screening criteria (see 5 of the guide material under §192.917) should adjust the criteria to reflect operating history when performing the threat identification, risk analysis, and assessment.

- (b) ASME B31.8S, Appendix A3.3 requires that each segment that has experienced a failure, leak, or hydrostatic test break caused by SCC be evaluated unless the conditions that led to SCC have been corrected (e.g., recoating with FBE).

4 PRIORITIZE COVERED SEGMENTS FOR ASSESSMENT

- (a) Prioritize segments. The operator is required to prioritize segments for SCC assessment (§192.929)(b)(1)). The amount of information available to enable prioritization may vary considerably. For first-time SCC assessment, there may be little information other than basic pipeline attributes. See NACE SP0204, Table 1 for a listing of data, records, results from other assessments, inspections

or evaluations, and ranking guidance.

- (1) For subsequent assessments, information from excavations of the HCA segment, together with excavation results from adjacent or similar segments, may enhance the analysis.
 - (2) For multiple covered segments identified as having SCC, the operator must prioritize the covered segments. This prioritization applies only to those covered segments with the threat of SCC. The results of this prioritization should not override the overall threat risk analysis.
- (b) Prioritization models. The following are examples of models the operator may use.
- (1) NACE SP0204. Section 3.2 and Table 1 provide guidance on prioritizing segments for excavation to determine the most likely locations to evaluate if SCC is present.
 - (2) ASME STP-PT-011. This report includes guidelines and algorithms for prioritizing pipeline segments for SCC assessment and for selecting excavation sites most likely to show evidence of SCC. The prioritization model is a three-tiered approach based on the likelihood of SCC occurring and the consequence (see Table 192.929ii). Highest priority segments are in the order of Tier 1 to Tier 3.

3-TIER PRIORITIZATION MODEL	
Tier	Level of Information
1	Prioritization based on pipeline attributes and operating history, with no information available from excavations or surveys.
2	Prioritization incorporating additional information from monitoring and surveys, ILI, excavations for other operational reasons, and any prior hydrostatic tests.
3	Prioritization augmented by feedback from previous SCC assessments, leading eventually to a series of pipeline-specific, weighted risk factors incorporated in an overall ranking model; such a model could form the basis for quantitative risk analysis.

TABLE 192.929ii

- (c) Identifying locations to excavate. Once segments are prioritized, the location to excavate should be the most likely location for SCC to exist. The following factors should be considered when determining excavation sites.
- (1) Segments with history of SCC.
 - (i) Near previous locations of SCC.
 - (ii) At locations having the same pipe characteristics as those associated with known SCC findings where any of the following is encountered.
 - (A) Dents.
 - (B) Geophysical features (e.g., soil moisture, drainage, soil type).
 - (C) Steep slopes with soil subsidence.
 - (D) Coating anomalies.
 - (2) Segments with no history of SCC.
 - (i) Locations with known coating anomalies, such as disbondment.
 - (ii) History of coating deterioration. For coatings such as coal tar or asphalt, these areas might be identified from a close-interval survey (CIS) or a coating-fault survey.
 - (iii) Locations of dents or general corrosion.
 - (iv) Locations where the stresses, pressure fluctuations, or temperatures have been highest.
 - (v) Locations where unique features have been discovered during earlier excavations, such as an overbend.
 - (3) See NACE SP0204, Section 3.3 for additional guidance on selecting excavation sites.

5 CONDUCT ASSESSMENT

- (a) In accordance with §192.929(b)(2), the operator is required to use an assessment specified in ASME B31.8S, Appendix A3. This appendix does allow other methods to be used (Appendix A3.1) in addition to those listed in Appendix A3.4.
- (b) In accordance with ASME B31.8S, Appendix A3.4, the operator is required to prepare a written inspection, examination, and evaluation plan. For guidance in writing a plan, see guide material under §192.925 (ECDA) and §192.927 (ICDA). An operator may already have written procedures for many of the required plan components. Existing procedures may be modified to meet the additional requirements of SCCDA.
- (c) When planning excavations for SCCDA, consider coordinating with other excavations such as those for ECDA and ICDA. See 5.2(g) of the guide material under §192.925.
- (d) Examination and evaluation.
 - (1) If a direct examination reveals no disbonded coating on a coated pipeline, SCC is not considered to be present. Therefore, it is not recommended to remove coating that is not disbonded.
 - (2) The operator is required to remove disbonded coating and, as with bare pipe, the surface must be inspected for SCC using magnetic particle inspection (MPI) with a documented inspection procedure (ASME B31.8S, Appendix A3.4.1(c)). When necessary, the method of coating removal is a function of the coating type. Care should be taken when removing coating to ensure that evidence of SCC is not damaged. See NACE SP0204, Table B1 for additional information on selection of surface preparation guidelines for MPI.
 - (3) Additional data elements to consider during excavation can be found in 5.3 of the guide material under §192.925, and NACE SP0204, Table 2, "Data Collected at a Dig Site in an SCCDA Program and Relative Importance."

6 REMEDIATION

- (a) No SCC indications found. If SCC is not found at the most likely location(s), an operator can conclude the integrity assessment and set the reassessment interval. See Table 192.939iv of the guide material under §192.939 regarding reassessment intervals for SCC.
- (b) SCC indications found.
 - (1) When SCC indications are detected, at least one of the following three mitigation methods is required to be used (ASME B31.8S, Appendix A3.4.1(d)(2)).
 - (i) *Evaluate repair or removal methods for SCC.* Industry research, such as the PRCI Pipeline Repair Manual (PR-218-9307), addresses repair methods for SCC.
 - (ii) *Hydrostatically test the covered segment.* See ASME B31.8S, Appendix A3.4.2.
 - (iii) *Engineering critical assessment (ECA).* An ECA is a process to document the evaluation of the risks of SCC and provide a technically valid plan that demonstrates satisfactory pipeline safety performance. The ECA should consider the defect growth mechanisms for the SCC process. For additional guidance on performing an ECA, see the following references.
 - (A) OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study," Michael Baker, Jr., Inc., January 2005
 - (B) ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas."
 - (2) The 2010 edition of ASME B31.8S provides guidance for addressing indications of SCC in Tables A-1, SCC "Crack Severity Criteria" and A-2, "Response to Bell Hole SCC Indications."

7 RECORDKEEPING

- (a) SCCDA records 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 SP0204, Section 7 for additional guidance on recordkeeping.

8 REFERENCES

- (a) ASME B31.8S-2010, "Managing System Integrity of Gas Pipelines." [*The 2010 Edition is not incorporated by reference.*]
- (b) ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas."
- (c) NACE Publication 35103, "External Stress Corrosion Cracking of Underground Pipelines."
- (d) NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."
- (e) National Energy Board (Canada), Report of the Inquiry MH-2-95, "Stress Corrosion Cracking on Canadian Oil and Gas Pipelines," December 1996.
- (f) OPS Advisory Bulletin ADB-03-05 (68 FR 58166, Oct. 8, 2003; see Guide Material Appendix G-192-1, Section 2).
- (g) OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study," Michael Baker, Jr., Inc., January 2005.
- (h) PRCI L52047, "Pipeline Repair Manual," PR-218-9307
- (i) PRCI L52043, "SCC Initiation Susceptibility Ranking/Screening," PR-273-0328.
- (j) Stress Corrosion Cracking Recommended Practices, 2nd Edition (CEPA).

§192.931

How may Confirmatory Direct Assessment (CDA) be used?

[Effective Date: 03/06/15]

An operator using the confirmatory direct assessment (CDA) method as allowed in §192.937 must have a plan that meets the requirements of this section and of §§192.925 (ECDA) and §192.927 (ICDA).

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

(b) **External corrosion plan.** An operator's CDA plan for identifying external corrosion must comply with §192.925 with the following exceptions.

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

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

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

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

(c) **Internal corrosion plan.** An operator's CDA plan for identifying internal corrosion must comply with §192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(d) **Defects requiring near-term remediation.** If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE SP0502 (incorporated by reference, see §192.7), section 6.2 and 6.3. If the 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.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004; Amdt. 192-103, 71 FR 33402, June 9, 2006; Amdt. 192-114, 75 FR 48593, Aug. 11, 2010; Amdt. 192-119, 80 FR 168, Jan. 5, 2015]

GUIDE MATERIAL

Note: References to NACE throughout this section of guide material are specific to the edition of NACE SP0502 as incorporated by reference (IBR) in §192.7. Abbreviated references are used in guide material below. Example: "NACE 1.1.7" means NACE SP0502, Paragraph 1.1.7 of the IBR edition. See 3 of the guide material under §192.907.

1 PURPOSE

Confirmatory Direct Assessment (CDA) is a methodology to assess the integrity of a pipeline that is subject to the threats of external corrosion and internal corrosion.

CDA may be used to meet the reassessment intervals of §192.939. See guide material under §192.939.

2 GENERAL REQUIREMENTS

- (a) If an operator uses CDA, a written CDA plan is required. The plan is to be based on the following.
 - (1) Section 192.931.
 - (2) Section 192.925, External Corrosion Direct Assessment (ECDA), with exceptions noted in §192.931(b).
 - (3) Section 192.927, Internal Corrosion Direct Assessment (ICDA), with exceptions noted in §192.931(c).
 - (4) NACE SP0502.
- (b) The CDA plan should include its purpose, objectives, and instructions to personnel. Operators who have performed ECDA or ICDA in previous assessments may use existing plans and supporting material as the basis for the CDA plan.
- (c) Section 192.931(b) requires that the CDA plan address the following process steps.
 - (1) For external corrosion, see §192.925(b) for general ECDA requirements.
 - (i) Pre-assessment.
 - (ii) Indirect examination (inspection) with exceptions noted in 3(a) below.
 - (iii) Direct examination.
 - (iv) Post-assessment and continuing evaluation.
 - (2) For internal corrosion, see §192.927(c) for the ICDA plan.
 - (i) Pre-assessment.
 - (ii) Region identification.
 - (iii) Identification of locations for excavation and direct examination with exceptions noted in 4(c) below.
 - (iv) Post-assessment evaluation and monitoring.
- (d) *First-time application.* If In-Line Inspection (ILI) or pressure testing were used for the baseline assessment, §§192.925 and 192.927 have additional requirements for first-time application. See guide material under §192.925 and 7 under §192.927.
- (e) Section 192.947(d) requires documents to support decisions, analyses, and processes developed and used to implement and evaluate the operator's integrity management program, including CDA.
- (f) The CDA plan may reference appropriate sections of other documents (e.g., ECDA written plan, Close-Interval Survey (CIS) procedure) instead of repeating them in the CDA plan. These documents should be available to personnel performing associated tasks.
- (g) The findings from or the use of CDA:
 - (1) May not be used to lengthen full assessment intervals.
 - (2) May require the operator to shorten full assessment intervals.
- (h) Operators who have identified threats other than external corrosion and internal corrosion must use appropriate assessment techniques to address those threats. See NACE 1.1.7.

Note: Operators using CDA are required to develop and implement a direct assessment plan. For ECDA, follow §192.925, ASME B31.8S, and NACE SP0502. For ICDA, follow §192.927, ASME B31.8S, and either GRI-02/0057 or its equivalent. Some operators, however, may elect to organize the CDA activities required within each of the process steps differently. For example, NACE SP0502 includes determining the minimum number of excavations (digs) in the direct examination step, whereas an operator may elect to include this item in the indirect inspection step. This re-organization of ECDA activities is generally acceptable, provided that all activities are addressed in the operator's direct assessment plan.

3 EXTERNAL CORROSION

- (a) *Pre-assessment.* See 3 of the guide material under §192.925, except that use of only one indirect examination tool is required. See §192.931(b)(1).
 - (1) The selection of which tool to use should be based on the operator's knowledge of the pipeline system. For example, if Cathodic Protection (CP) readings have historically been lower than expected, the operator may choose to use an indirect inspection tool that will provide CP information such as CIS. If the operator has information that the condition of the coating is subject to damage, the operator may choose to perform a coating survey such as Direct Current Voltage Gradient (DCVG).
 - (2) Operators should evaluate previous assessment results to aid in determining which tool to select. For example, if a previous ILI run discovered third-party damage, then the operator may choose to perform a coating survey such as DCVG.
- (b) *Indirect examination (inspection).* See 4 of the guide material under §192.925. The operator should align and compare the results of the CDA inspection tool with previous integrity assessment results and O&M records. The alignment and comparison of CDA indirect inspection information with ECDA information may assist in developing trending to determine if continuous improvement is being made.

If ECDA was previously performed, the operator should consider performing the CDA indirect examination under similar conditions (e.g., seasons).

- (c) *Direct examination.* See 5 of the guide material under §192.925.
 - (1) An operator is required to excavate all immediate conditions (NACE 5.10.2.1).
 - (2) For each region, if there is more than one scheduled indication, then perform an excavation on the most severe scheduled indication in that region. See §192.931(b)(2)(ii).
 - (3) Provided that ECDA or CDA has been conducted before and if no immediate or scheduled indications exist, direct examination is not required. See §192.931(b)(2).
 - (4) A post validation excavation (direct examination) is not required if ECDA was conducted previously on the covered segment. See §192.931(b)(2).
- (d) *Post-assessment.* See 6 of the guide material under §192.925, except that a post validation is not required.

4 INTERNAL CORROSION

- (a) *Pre-assessment.* See 3 of the guide material under §192.927.
- (b) *Region identification.* See 4 of the guide material under §192.927.
- (c) *Identification of locations for excavation and direct examination.* See 5 of the guide material under §192.927, except that an operator is required to perform only one direct examination at only one high-risk location in each ICDA region. See §192.931(c). A high-risk location is meant to be a point where internal corrosion is likely to occur within an HCA.
- (d) *Post-assessment evaluation and monitoring.* See 6 of the guide material under §192.927.

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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GUIDE MATERIAL

This guide material is under review following Amendment 192-132.

1 DISCOVERY OF CONDITION

- (a) The operator is expected to define "discovery of condition" in its written integrity management program because that date sets the schedule for evaluation and remediation. Conditions may be discovered as soon as the assessment is completed. Some of these may require immediate action. However, the operator generally has no more than 180 days after completing an assessment to discover a condition that presents a potential threat to the integrity of the pipeline. The operator should document the date each condition was discovered.
- (b) Assessment is considered complete after fully executing any one of the following.
 - (1) Hydrostatic test.
 - (2) Last in-line inspection (ILI) tool run of a scheduled series of tool runs.
 - (3) Last direct examination associated with direct assessment.
 - (4) Completion of field activities associated with "other technology" for which an operator has provided timely notification as required by §192.921(a)(4).
- (c) "Discovery of condition" is dependent on the integrity assessment technique that is used as shown in Table 192.933i.
- (d) "Discovery of condition" under §192.933(b) is not necessarily the same as "Discovery" under §191.25. See 3(a) below.

ESTABLISHING "DISCOVERY OF CONDITION" DATE	
Assessment Technique	Discovery of Condition Typically Occurs When:
In-Line Inspection (ILI)	The operator receives a graded or characterized set of indications, or other data, from the inspection device and an analysis indicates a condition exists that could be a threat to pipeline integrity.
Pressure Testing	A leak that indicates a condition that could be a threat to pipeline integrity is observed or a failure occurs.
Direct Assessment	Direct examination or analysis of direct examination data indicates a condition that is a threat to pipeline integrity. The analysis should be completed as soon as practical after the direct examination.

TABLE 192.933i

2 SCHEDULE FOR EVALUATION AND REMEDIATION

2.1 Immediate repair conditions.

- (a) "Immediate repair conditions" are indications that a defect has failed or may be close to failure. These conditions require action within 5 days of discovery. Although §192.933 uses the term "immediate repair condition," a repair is not always required within the 5-day period. A temporary reduction of pressure (see §192.933(a)) will allow the pipeline to continue to operate.
- (b) For immediate repair conditions that result from analysis of ILI data, an evaluation of the indication must be conducted within five days of discovery.
- (c) For ILI and DA, immediate repair conditions include any of the following.

- (1) An indicated corrosion defect that yields a predicted failure pressure of less than 1.1 times the MAOP.
 - (2) A dent that has any indication of metal loss, cracking, or a stress riser (see Table 192.933ii).
 - (3) An indication of stress corrosion cracking.
 - (4) A metal loss indication affecting a detected longitudinal seam in low-frequency ERW pipe or pipe produced by electric flash welding.
 - (5) Other indications that might be expected to cause immediate failure or, in the judgment of the operator, require immediate action.
- (d) For ECDA, "immediate indications" only become "immediate repair conditions" when direct examination indicates a defect that meets one of the above criteria.
- (e) For repair information, see guide material under 192.713.

2.2 *One-year conditions.*

Dents requiring repair within one year are listed in Table 192.933ii.

2.3 *Scheduled conditions.*

Corrosion indications are required to be analyzed for predicted failure pressure in accordance with ASME B31G, PRCI PR-3-805 (RSTRENG) (see §192.7 for IBR for both), or equivalent method. The failure pressure (P_f) is divided by the MAOP to determine a safety factor. The safety factor and operating percent of SMYS determine the maximum time interval for evaluation and remediation. The maximum time interval for responding to scheduled defects may be obtained from ASME B31.8S-2004, Section 7, Figure 4 (see §192.7 for IBR).

2.4 *Monitored conditions.*

Dents that can be monitored are included in Table 192.933ii.

REMEDIATION OF DENTS			
Pipe Size	Dent Location	Description	Schedule
Any	Any	A dent that contains a crack, stress riser, or has metal loss.	Immediate
Less than 12"	Any	A dent with a depth ¹ greater than 0.25 inches that affects a girth weld or longitudinal weld seam, with no engineering analysis.	One year
	Any	A dent with a depth ¹ greater than 0.25 inches that affects a girth weld or longitudinal weld seam and engineering analysis demonstrates critical strain levels are not exceeded.	Monitor
	Top 2/3 of pipe	A smooth dent with a depth ¹ greater than 0.5 inches, with no engineering analysis.	One year
	Top 2/3 of pipe	A dent with a depth ¹ greater than 0.5 inches, and engineering analysis demonstrates critical strain levels are not exceeded.	Monitor
	Bottom 1/3 of pipe	A dent with a depth ¹ greater than 0.5 inches.	Monitor

TABLE 192.933ii (Continued)

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 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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Addendum 1, June 2022

Addendum 2, February 2023

GUIDE MATERIAL

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

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(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.

ADDITIONAL P&M MEASURES FOR TRANSMISSION PIPELINES OPERATING BELOW 30 PERCENT SMYS AND PLASTIC TRANSMISSION LINES					
Location	General Requirements	Use Qualified Personnel	Participate in one-call	Monitor Excavations or Additional Patrol	Additional Leak Survey
Class 1 & 2 in HCA	X	X	X	X	
Class 1 & 2 outside HCA					
Class 3 & 4 in HCA	X	X	X	X	
Class 3 & 4 outside HCA		X	X	X	X
Plastic Transmission	X	X	X	X (monitor only) ¹	

¹ The option of patrolling is not available for plastic transmission lines.

TABLE 192.935i

§192.937

What is a continual process of evaluation and assessment to maintain a pipeline’s integrity?

[Effective Date: 07/10/06]

(a) **General.** After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) **Evaluation.** An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) **Assessment methods.** In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (see §192.917), or by confirmatory direct assessment under the conditions specified in §192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.

[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]

GUIDE MATERIAL

1 GENERAL

See the guide material under §192.939 for reassessment intervals.

2 EVALUATION FOR COVERED SEGMENTS

One of the goals of periodic evaluation is to determine what is changing and what actions are needed to maintain safe operations. Periodic evaluations are based on integrating information, identifying changes to pipeline threats, and updating risk analyses. This evaluation is intended to support the identification of changes needed to assessment frequencies, assessment types, and preventive and mitigative (P&M) measures.

2.1 Frequency.

When determining the frequency, the operator should consider the following.

- (a) The number and types of changes that are occurring. For example, if there are no changes to HCAs, MAOPs, or personnel, a longer interval may be appropriate.
- (b) For pipe subject to low stress reassessment, the requirement to evaluate external corrosion data for:
 - (1) Cathodically protected lines at least once every 7 years (§192.941(b)(1)), or
 - (2) Unprotected pipe at least once every 18 months (§192.941(b)(2)).
- (c) For pipe subject to low stress reassessment, the requirement to evaluate internal corrosion data at least once every 7 years (§192.941(c)(3)).
- (d) The evaluation intervals should not exceed the assessment intervals listed in ASME B31.8S-2004, Section 5, Table 3 (see §192.7 for IBR).
- (e) Items that might trigger an evaluation (e.g., incidents, new data) before the scheduled evaluation.

2.2 *Data integration.*

Use information collected through assessment, remediation, and P&M measures to update records where default values were used, or that have been determined to be inaccurate or incomplete.

2.3 *Threat identification.*

Use information collected through assessment, remediation, and P&M measures to identify new threats or to evaluate the severity of existing threats. Additional changes to threats may be identified through the evaluation of the following.

- (a) Failures.
- (b) Incidents.
- (c) Abnormal operations.
- (d) Lessons learned.
- (e) Performance metrics.

2.4 *Risk analysis.*

- (a) Use information collected through assessment, remediation, and P&M measures to determine if the risk ranking is consistent with the results.
- (b) Use information collected through data integration, assessment, remediation, and P&M measures to update the risk model.
- (c) Changes to segments included in risk assessment may be identified through the evaluation of the following.
 - (1) System modifications.
 - (2) HCA changes.
 - (3) O&M activities.
 - (4) Operational changes.
 - (5) Environmental changes.

2.5 *Subsequent actions driven by periodic evaluation.*

- (a) Identify changes required to assessment intervals.
- (b) Confirm that assessment methods are applicable for the identified threats.
- (c) If current methods are not effective for current threats, determine correct assessment methods and reassess applicable segments.
- (d) Determine the effectiveness of current P&M measures.
- (e) Determine the need for changes to existing P&M measures or implementation of additional measures.
- (f) If an operator changes the criteria for grading ILI anomalies, the operator should review the impact of the changes on anomalies discovered during the prior assessments.
- (g) If an operator changes ECDA or ICDA criteria for classifying indications, or for calculating the remaining life, the operator should review the impact of the changes on the results from the prior assessment.
- (h) Evaluate the potential requirement for assessment and remediation of a threat on other pipeline segments as follows.
 - (1) Similar pipeline segments when corrosion or seam issues are identified as a threat in a covered segment.
 - (2) Similar covered segments when any threats are identified outside a covered segment.

3 ASSESSMENT METHODS

- (a) For reassessment methods, see the guide material under §192.921.
- (b) For CDA, see guide material under §192.931.
- (c) For assessment conducted to satisfy MAOP reconfirmation, see guide material under §192.624(c). Such an assessment might not qualify as an integrity assessment under §192.937.

§192.939

What are the required reassessment intervals?

[Effective Date: 03/06/15]

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

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

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

(i) Basing the interval on the identified threats for the covered segment (see §192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME B31.8S (incorporated by reference, see §192.7), section 5, Table 3.

(2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, see §192.7).

(3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

(i) Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil and protection conditions;

(ii) Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

(iii) Estimate the reassessment interval as half the time required for the largest defect to grow to a critical size.

(b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following —

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this

section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

Maximum Reassessment Interval			
Assessment Method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years(**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low Stress Reassessment	Not Applicable	Not Applicable	7 years + ongoing actions specified in §192.941
(*) A Confirmatory direct assessment as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.			
(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.			

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GUIDE MATERIAL

1 GENERAL

The factors that determine the reassessment interval include the following.

- (a) Operating stress levels.
- (b) Type of prior assessment.
- (c) Analysis of defects from prior assessment.
- (d) Prescriptive or performance based programs.
- (e) Requirement for a 7-year reassessment interval.

2 MAXIMUM REASSESSMENT INTERVALS

- (a) Tables 192.939i through 192.939iv and Appendix E to Part 192 list the maximum permitted reassessment intervals based on type of prior assessment and operating stress level. If the maximum permitted time interval for an assessment method exceeds 7 calendar years, a confirmatory direct assessment (see §192.931 regarding CDA) or other assessment must be conducted at intervals not exceeding 7 calendar years (§192.939(a) and (b)).
- (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)). The operator should state why the extension is needed and how it will not compromise safety. Additional actions to ensure public safety (e.g., leak surveys, patrols) during the extension should also be considered and noted in the application. The following are examples of what might be considered as sufficient justification for an extension.
- (1) Weather-related or natural disaster conditions.
 - (2) Assessment tool availability or malfunctions.
 - (3) Changes in field or operating conditions.
 - (4) Gas supply issues.
 - (5) Permitting issues.
 - (6) Public health concerns, such as a pandemic.
- (c) Based on the threats and conditions found, reassessment may be required at intervals less than the maximum.

MAXIMUM REASSESSMENT INTERVALS FOR IN-LINE INSPECTION (ILI)			
Stress Level	Ratio of Predicted Failure Pressure (FP) of Remaining Defects to the MAOP	Maximum Interval Based on prior assessments, data integration, and risk assessment using reasonably anticipated or scientifically proven rate of defect growth. [§192.939(a)(1)(i)]	Maximum Interval Based on ASME B31.8S-2004, Section 5, Table 3 (see §192.7 for IBR). [§192.939(a)(1)(ii)]
≥ 50% SMYS	FP exceeds 1.25 times MAOP	7 years	5 years
	FP exceeds 1.39 times MAOP	10 years	10 years
< 50% and ≥ 30% SMYS	FP exceeds 1.4 times MAOP	15 years	5 years
	FP exceeds 1.7 times MAOP	15 years	10 years
	FP exceeds 2.0 times MAOP	15 years	15 years
< 30% SMYS (Low stress reassessment may be used; see §192.941)	FP exceeds 1.7 times MAOP	20 years	5 years
	FP exceeds 2.2 times MAOP	20 years	10 years
	FP exceeds 2.8 times MAOP	20 years	15 years
	FP exceeds 3.3 times MAOP	20 years	20 years

TABLE 192.939i

MAXIMUM REASSESSMENT INTERVALS FOR PRESSURE TESTING		
Stress Level	Ratio of test pressure (TP) to the MAOP	Maximum Interval
≥ 50% SMYS	Testing in accordance with Subpart J	7 years
	TP exceeds 1.39 times MAOP	10 years
< 50% and ≥ 30% SMYS	Testing in accordance with Subpart J	7 years
	TP exceeds 1.7 times MAOP	10 years
	TP exceeds 2.0 times MAOP	15 years
< 30% SMYS (Low stress reassessment may be used; see §192.941)	Testing in accordance with Subpart J	7 years
	TP exceeds 2.2 times MAOP	10 years
	TP exceeds 2.8 times MAOP	15 years
	TP exceeds 3.3 times MAOP	20 years

TABLE 192.939ii

MAXIMUM REASSESSMENT INTERVALS FOR EXTERNAL CORROSION DIRECT ASSESSMENT		
Stress Level	Results of Examinations	Maximum Interval
≥ 50% SMYS	No corrosion defects found	10 years
	Corrosion defects found	Minimum of calculated remaining half-life or 10 years
< 50% and ≥ 30% SMYS	No corrosion defects found	15 years
	Corrosion defects found	Minimum of calculated remaining half-life or 15 years
< 30% SMYS (Low stress reassessment may be used; see §192.941)	No corrosion defects found	20 years
	Corrosion defects found	Minimum of calculated remaining half-life or 20 years

TABLE 192.939iii

MAXIMUM REASSESSMENT INTERVALS FOR INTERNAL CORROSION DIRECT ASSESSMENT AND STRESS CORROSION CRACKING DIRECT ASSESSMENT				
Stress Level	ICDA		SCCDA	
	Results of Examinations	Maximum Interval	Results of Examinations	Maximum Interval
> 50% SMYS	Critical angle examined	10 years	All indications examined	10 years
			All indications not examined	Lower of calculated remaining half-life or 5 years
< 50% and ≥ 30% SMYS	Critical angle examined	15 years	All indications examined	15 years
			All indications not examined	Lower of calculated remaining half-life or 10 years
< 30% SMYS (Low stress reassessment may be used; see §192.941)	Critical angle examined	20 years	All indications examined	20 years
			All indications not examined	Lower of calculated remaining half-life or 10 years

TABLE 192.939iv

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

This guide material is under review following Amendment 192-132.

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.

Addendum 2, February 2023

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- (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 4(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 "waiver" 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 listing in §192.7, not IBR for §192.945).

§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.

1.2 Revisions to the Integrity Management Program (IMP).

Copies of revisions to the integrity management program should be kept for documentation. If changes are made to the program as a result of revisions to standards or regulations, copies of the historical and current versions of the standards should be kept. Note that significant changes to the operator's program require notification to PHMSA-OPS or state pipeline safety authorities. See guide material under §192.18.

1.3 Threat identification and risk assessment.

Documentation for threat identification, threat status, and risk assessment might include the following.

- (a) Description of the process used for risk analysis.
- (b) History of risk analysis results.
- (c) Minutes from subject matter expert meetings.
- (d) Rationale of analyses, justifications, determinations, and decisions
- (e) List of threats.

1.4 Baseline assessment plans.

Operators should retain and record the technical basis for changes to their baseline assessment plans. Operators should retain adequate documentation to illustrate how their plans have changed and the technical justification for those changes. Documentation might include historical and current records as follows.

- (a) Schedules.
- (b) Threat lists and assessment methods.
- (c) Direct assessment plans.
- (d) Environmental and safety procedures.

2 TRAINING AND QUALIFICATION OF PERSONNEL

Documentation for employee training and qualification might include the following.

- (a) Training curriculum.
- (b) Training outlines.
- (c) Training schedules.
- (d) Sample tests.
- (e) Employee training records.

3 ONGOING ACTIVITY

3.1 Evaluation and remediation.

Documentation for the evaluation and remediation schedule might include the following.

- (a) List of conditions found.
- (b) Repairs, monitoring, replacements, or pressure reductions performed.
- (c) Priority of conditions.
- (d) Scheduled evaluation or remediation date.
- (e) Written justification for assigning priority.

3.2 Direct and confirmatory assessment.

Documentation for direct and confirmatory assessments might include the following.

- (a) Procedures for assessment methods.
- (b) Criteria for evaluating assessment results.
- (c) Tool selection criteria.
- (d) Forms or other documentation of field data.

4 REGULATORY CORRESPONDENCE

Documentation of correspondence with PHMSA-OPS and state pipeline safety agencies relating to integrity management issues should be retained.

§192.949

(Removed and reserved.)

[Effective Date: 10/01/15]

§192.951

Where does an operator file a report?

[Effective Date: 01/01/11]

An operator must file any report required by this subpart electronically to the Pipeline and Hazardous Materials Safety Administration in accordance with §191.7 of this subchapter.

[Issued by Amdt. 192-95, 68 FR 69778, Dec. 15, 2003 with Amdt. 192-95 Correction, 69 FR 2307, Jan. 15, 2004; RIN 2137-AD77, 70 FR 11135, Mar. 8, 2005; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; RIN 2137-AE29, 73 FR 16562, Mar. 28, 2008; RIN 2137-AE29 (#2), 74 FR 2889, Jan. 16, 2009; Amdt. 192-115, 75 FR 72878, Nov. 26, 2010]

GUIDE MATERIAL

REFERENCES

See the following sections for information regarding specific reporting requirements.

- (a) Section 192.945, regarding performance measures.
- (b) Section 192.913, regarding additional performance measures for exceptional performance programs.
- (c) Sections 192.913 and 192.945 do not require reporting to state pipeline safety agencies. However, intrastate operators should consider submitting a copy of the reports to their state agency even if state reporting requirements do not exist for intrastate facilities.

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Appendix C to Part 192 Qualification of Welders for Low Stress Level Pipe.

[Effective Date: 07/14/04]

I. **Basic test.** The test is made on pipe 12 inches (305 millimeters) or less in diameter. The test weld must be made with the pipe in a horizontal fixed position so that the test weld includes at least one section of overhead position welding. The beveling, root opening, and other details must conform to the specifications of the procedure under which the welder is being qualified. Upon completion, the test weld is cut into four coupons and subjected to a root bend test. If, as a result of this test, two or more of the four coupons develop a crack in the weld material, or between the weld material and base metal, that is more than 1/8-inch (3.2 millimeters) long in any direction, the weld is unacceptable. Cracks that occur on the corner of the specimen during testing are not considered. A welder who successfully passes a butt-weld qualification test under this section shall be qualified to weld on all pipe diameters less than or equal to 12 inches.

II. **Additional tests for welders of service line connections to mains.** A service line connection fitting is welded to a pipe section with the same diameter as a typical main. The weld is made in the same position as it is made in the field. The weld is unacceptable if it shows a serious undercutting or if it has rolled edges. The weld is tested by attempting to break the fitting off the run pipe. The weld is unacceptable if it breaks and shows incomplete fusion, overlap, or poor penetration at the junction of the fitting and run pipe.

III. **Periodic tests for welders of small service lines.** Two samples of the welder's work, each about 8 inches (203 millimeters) long with the weld located approximately in the center, are cut from steel service line and tested as follows:

(1) One sample is centered in a guided bend testing machine and bent to the contour of the die for a distance of 2 inches (51 millimeters) on each side of the weld. If the sample shows any breaks or cracks after removal from the bending machine, it is unacceptable.

(2) The ends of the second sample are flattened and the entire joint subjected to a tensile strength test. If failure occurs adjacent to or in the weld metal, the weld is unacceptable. If a tensile strength testing machine is not available, this sample must also pass the bending test prescribed in subparagraph (1) of this paragraph.

[Amdt. 192-85, 63 FR 37500, July 13, 1998; Amdt. 192-94, 69 FR 32886, June 14, 2004]

GUIDE MATERIAL

1 GENERAL

- (a) When qualifying welders under Appendix C, the following should be considered to ensure that the welders are qualified to weld on pipe to be operated at a hoop stress of less than 20% SMYS. Test weld sample preparation should be observed by qualified personnel.
- (b) A welder should successfully complete the Service Line Connection Test to be qualified to weld service-line connections to mains. A welder should successfully complete the Tests for Welders of Small Service Lines to be qualified to weld pipe less than NPS 2.
- (c) For qualification of welding operators, see guide material under §192.227.

2 BASIC TEST

- (a) The test welds must be made on NPS 12 or less pipe. It is suggested the specific pipe sizes for tests be typical of those anticipated to be encountered most frequently by the welder.
- (b) Four test specimen coupons should be prepared. For pipe sizes NPS 2 or above, the test specimen coupons should be prepared as shown in Figure CA (1) and taken from the locations shown in Figure CA (2). Two test welds are needed for pipe sizes less than NPS 2 with the specimen coupons taken at alternate quadrants of each weld as shown in Figure CA (3).
- (c) A guided bend test jig proportioned as shown in Figure CB is suggested for the root bend test. The root of the weld should be placed down on the die with the weld at mid-span. The plunger should be forced down until the curvature of the test coupon is approximately "U" shaped.

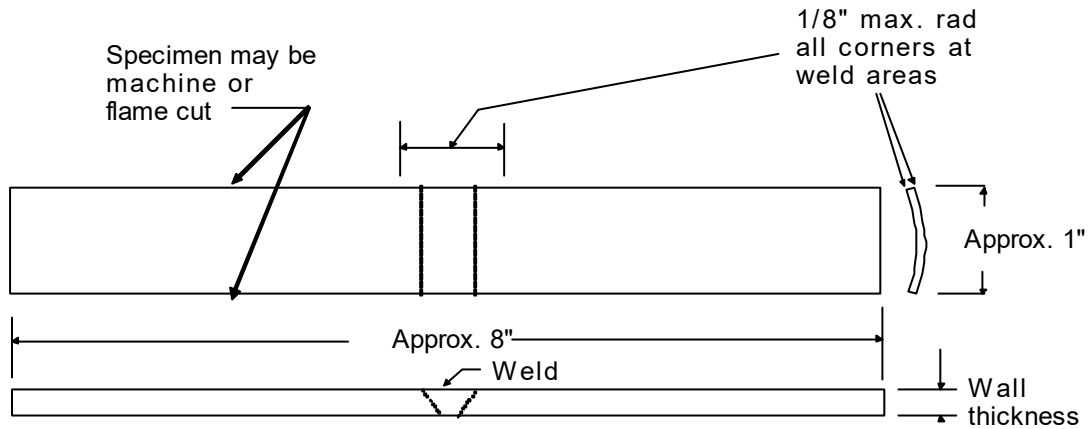
3 ADDITIONAL TESTS FOR WELDERS OF SERVICE-LINE CONNECTIONS TO MAINS

- (a) This test is made by welding a service-line connection fitting to a segment of pipe having a nominal pipe size typical of that frequently encountered, or an NPS 4 pipe segment. Nipples may be used for welder tests in place of a service-line connection fitting.
- (b) Where large-diameter service-line connection fittings or large main branching tees are anticipated to be encountered by the welder, it may be appropriate to give the welder an additional test for such configurations. The test weld branch nipple should be destructively tested following API Std 1104, Section 5.8, Testing of Welded Joints — Fillet Welds, and Section 6.5.6, Sampling of Test — Fillet Welds (see listing in §192.7, not IBR for Appendix C).

4 PERIODIC TESTS FOR WELDERS OF SMALL SERVICE LINES

- (a) This weld test should be accomplished using pipe of NPS $\frac{3}{4}$ to NPS 1 or other size typically encountered by the welder when qualifying to weld pipelines of less than NPS 2.
- (b) The beveling, root opening, and weld details should conform to the specifications of the procedure under which the welder is to be qualified.
- (c) One test specimen coupon is needed from each of two weld samples prepared as shown in Figure CA (1). The test jig should conform to Figure CB.

Root Bend Test Specimen



Weld reinforcement shall be removed from both faces flush with the surface of the specimen. Specimen shall not be flattened prior to testing.

FIGURE CA (1)

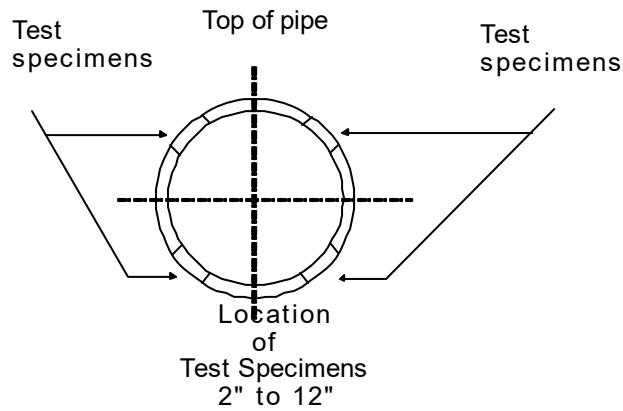


FIGURE CA (2)

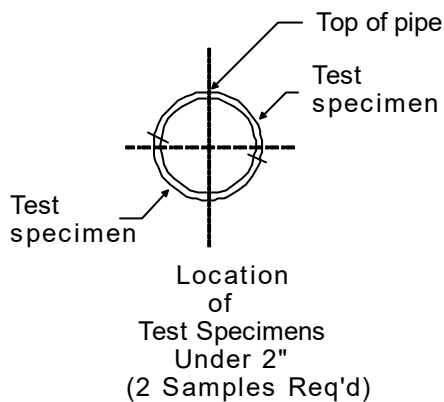
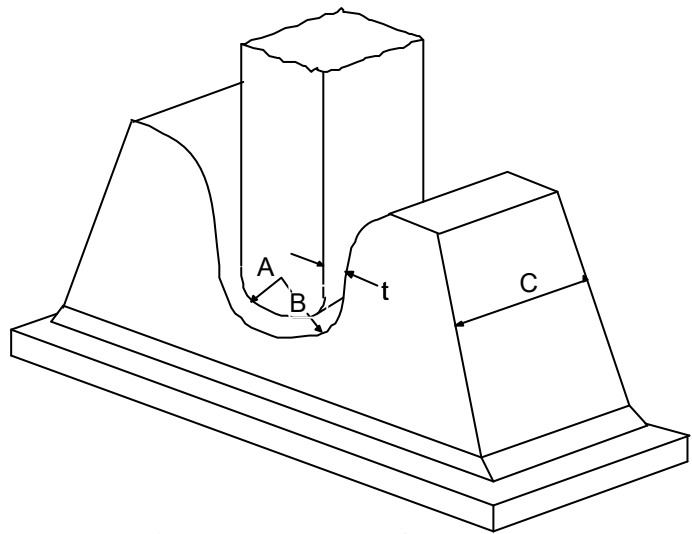


FIGURE CA (3)

Jig for Guided Bend



- Radius of plunger A = 1 3/4"
- Radius of die B = 2 15/16"
- Width of die C = 2"
- Thickness of specimen t = 0.500" max.

FIGURE CB

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GUIDE MATERIAL APPENDIX G-192-1

SUMMARY OF REFERENCES AND RELATED SOURCES

CONTENTS

1 MATERIAL SPECIFICATIONS, CODES, STANDARDS, AND OTHER DOCUMENTS

- 1.1 Pipe: Metallic
- 1.2 Pipe: Plastic [See "Plastic Related"]
- 1.3 Valves [See other related references under "Flanges" and "Materials & Fittings: Miscellaneous"]
- 1.4 Flanges
- 1.5 Fittings: Threaded & Socket-Weld
- 1.6 Fittings: Welded
- 1.7 Materials & Fittings: Miscellaneous
- 1.8 Bolts & Gaskets
- 1.9 Corrosion Related
- 1.10 Dimensional Standards
- 1.11 Plastic Related
- 1.12 Pressure & Flow Devices
- 1.13 Structure Steel & Supports
- 1.14 Other Documents

2 GOVERNMENTAL DOCUMENTS

3 TECHNICAL PAPERS & PUBLICATIONS

- 3.1 Emergency Related
- 3.2 Corrosion Related
- 3.3 Plastic Related
- 3.4 Uncased Pipe and Directional Drilling Related
- 3.5 Safety and Integrity Management Related
- 3.6 General

4 PUBLISHING ORGANIZATIONS

5 ADDITIONAL INFORMATION RESOURCES

6 SUMMARY OF PRIMARY WEBSITES

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GUIDE MATERIAL APPENDIX G-192-1

SUMMARY OF REFERENCES AND RELATED SOURCES

Note: GMA means Guide Material Appendix.

1 MATERIAL SPECIFICATIONS, CODES, STANDARDS, AND OTHER DOCUMENTS

- The publications listed below provide information on pipe, components, specifications, and topics other than those covered currently or previously by Part 192. This list is intended to include all such publications referenced throughout the guide material and related appendices. See §192.7 for "Documents incorporated by reference" and Guide Material Appendix G-192-1A for other documents that have been previously incorporated by reference in the Regulations.
- For some publication titles, certain initial words have been omitted for brevity (e.g., ASTM B43, "Standard Specification for Seamless Red Brass Pipe, Standard Sizes" is presented here as "Seamless Red Brass Pipe, Standard Sizes").
- Under some conditions, the application of the information is limited by provisions of Part 192 and this Guide.
- See Editorial Conventions of the Guide for explanation of "Discontinued or Withdrawn." Discontinued or withdrawn publications may still be beneficial to operators, and Guide users should note that they may be available from industry collections maintained by gas operators, industry associations, institutions, or technical schools, colleges, and universities (see Sections 4 and 5).
- Most material specifications, codes, standards, and many other documents have been developed and approved in accordance with American National Standards Institute (ANSI) procedures and typically carry added identification referencing ANSI. Such identification is not routinely shown in the Guide.
- The appropriate guide material section is listed for each publication where applicable.
- Unless otherwise noted, the publications listed below are intended to be the latest available editions.

1.1 PIPE: METALLIC [See other related references under 1.14 Other documents]		
ANSI A21.52	Ductile – Iron Pipe, Centrifugally Cast, for Gas (Revised 1991; Withdrawn 1996)	GMA G-192-18
API Spec 5L Comparison	Detailed comparison of API 5L (43rd) & API 5L (44th) Requirements, printed June 9, 2009	§192.7
ASME B36.10M	Welded and Seamless Wrought Steel Pipe	§192.279
ASME I00396	History of Line Pipe Manufacturing in North America	§192.3 §192.917
ASTM A120	Pipe, Steel, Black and Hot-Dipped, Zinc-Coated (Galvanized) Welded and Seamless for Ordinary Uses (Withdrawn 1987; Replaced by ASTM A53 – IBR in §192.7)	
ASTM A155	Electric-Fusion Welded Steel Pipe for High-Pressure Service (Withdrawn 1978; Replaced by ASTM A671 – IBR in §192.7)	
ASTM A377	Specifications for Ductile-Iron Pressure Pipe	GMA G-192-18

Table Continued

1.1 PIPE: METALLIC (Continued)		
ASTM B43	Seamless Red Brass Pipe, Standard Sizes	
ASTM D3895	Standard Test Method for Oxidative-Induction Time of Polyolefins by Differential Scanning Calorimetry	§192.613
AWWA C101	Thickness Design of Cast Iron Pipe (Revised 1967; Withdrawn 1982)	GMA G-192-18
AWWA C150	Thickness Design of Ductile-Iron Pipe	
AWWA Manual M41	Ductile-Iron Pipe and Fittings	
1.2 PIPE: PLASTIC [See 1.11 Plastic Related]		
1.3 VALVES [See other related references under 1.4 Flanges, 1.7 Materials & Fittings: Miscellaneous, and 1.12 Pressure & Flow Devices]		
API Std 600	Steel Gate Valves – Flanged and Butt-welding Ends, Bolted Bonnet	§192.145
ASME B16.33	Manually Operated Metallic Gas Valves for Use in Gas Piping Systems Up to 175 psig (Sizes NPS ½ - NPS 2)	§192.145
ASME B16.34	Valves - Flanged, Threaded, and Welding End	§192.145
ASME B16.38	Large Metallic Valves for Gas Distribution (Manually Operated, NPS 2½ to 12, 125 psig Max)	§192.145
ASME B16.40	Manually Operated Thermoplastic Gas Shutoffs and Valves in Gas Distribution Systems	§192.145
1.4 FLANGES		
ASME B16.36	Orifice Flanges	§192.147
ASME B16.47	Large Diameter Steel Flanges (NPS 26 through NPS 60)	§192.147
ASME B16.48	Line Blanks	§192.147
AWWA C207	Steel Pipe Flanges for Waterwork Service, Sizes 4 Inch Through 144 Inch	§192.147
1.5 FITTINGS: THREADED & SOCKET-WELD		
ASME B16.3	Malleable Iron Threaded Fittings; Classes 150 and 300	§192.149
ASME B16.4	Gray Iron Threaded Fittings: Classes 150 and 250	§192.149
ASME B16.11	Forged Fittings, Socket Welding and Threaded	§192.149 GMA G-192-5
ASME B16.14	Ferrous Pipe Plugs, Bushings and Locknuts with Pipe Threads	§192.149

Table Continued

1.5 FITTINGS: THREADED & SOCKET-WELD (Continued)		
ASME B16.15	Cast Copper Alloy Threaded Fittings: Classes 125 and 250	§192.149
ASTM A733	Welded and Seamless Carbon Steel and Austenitic Stainless Steel Pipe Nipples	§192.149
MSS SP-79	Socket-Welding Reducer Inserts	§192.149
MSS SP-83	Class 3000 and 6000 Steel Pipe Unions, Socket Welding and Threaded	§192.149
1.6 FITTINGS: WELDED		
ASME B16.9	Factory-Made Wrought Buttwelding Fittings	§192.149
ASME B16.25	Buttwelding Ends	
ASME B16.49	Factory-Made, Wrought Steel, Buttwelding Induction Bends for Transportation and Distribution Systems	§192.149
MSS SP-75	High-Strength Wrought, Butt-Welding Fittings	§192.149 §192.157
1.7 MATERIALS & FITTINGS: MISCELLANEOUS		
ANSI A21.14	Ductile Iron Fittings, 3-Inch Through 24-Inch for Gas (Revised 1989; Withdrawn 1994)	
ASME B16.18	Cast Copper Alloy Solder Joint Pressure Fittings	
ASME B16.22	Wrought Copper and Copper Alloy Solder-Joint Pressure Fittings	
ASTM A105	Carbon Steel Forgings for Piping Applications	
ASTM A181	Carbon Steel Forgings for General-Purpose Piping	
ASTM A182	Forged or Rolled Alloy and Stainless Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service	
ASTM A234	Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High Temperature Service	
ASTM A350	Carbon and Low-Alloy Steel Forgings, Requiring Notch Toughness Testing for Piping Components	
ASTM A403	Wrought Austenitic Stainless Steel Piping Fittings	
ASTM A420	Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low-Temperature Service	
AWWA C111 / ANSI 21.11	Rubber-Gasket Joints for Ductile-Iron Pressure Pipe and Fittings	GMA G-192-1A

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1.7 MATERIALS & FITTINGS: MISCELLANEOUS (Continued)		
AWWA Manual M41	Ductile-Iron Pipe and Fittings	
MSS SP-6	Standard Finishes for Contact Faces of Pipe Flanges and Connecting-End Flanges of Valves and Fittings	§192.147
1.8 BOLTS & GASKETS		
AGA CPR-83-4-1	Threaded Fasteners Torquing (<i>Available on GPTC website under Reports and Position Papers</i>)	
ASME B1.1	Unified Inch Screw Threads (UN and UNR Thread Form)	§192.147
ASME B16.20	Metallic Gaskets for Pipe Flanges	§192.147
ASME B16.21	Non-metallic Flat Gaskets for Pipe Flanges	
ASME B18.2.1	Square, Hex, Heavy Hex, and Askew Head Bolts and Hex, Heavy Hex, Hex Flange, Lobed Head, and Lag Screws (Inch Series)	§192.147
ASME B18.2.2	Nuts for General Applications: Machine Screw Nuts, Hex, Square, Hex Flange, and Coupling Nuts (Inch Series)	§192.147
ASTM A193	Alloy-Steel and Stainless Steel Bolting for High-Temperature or High Pressure Service and Other Special Purpose Applications	§192.147
ASTM A194	Carbon, Alloy Steel, and Stainless Steel Nuts for Bolts for High-Pressure or High-Temperature Service, or Both	§192.147
ASTM A307	Carbon Steel Bolts, Studs, and Threaded Rod 60,000 PSI Tensile Strength	§192.147
ASTM A320	Alloy-Steel and Stainless Steel Bolting for Low-Temperature Service	§192.147
ASTM A354	Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners	§192.147
ASTM A449	Hex Cap Screws, Bolts and Studs, Steel, Heat Treated, 120/105/90 ksi Minimum Tensile Strength, General Use	§192.147
1.9 CORROSION RELATED		
ASME STP-PT-011	Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas	§192.613 §192.929
ASTM B117	Standard Practice for Operating Salt Spray (Fog) Apparatus	§192.461
CEPA	Stress Corrosion Cracking Recommended Practices, 2 nd Ed	§192.929
GTI-04/0071	External Corrosion Direct Assessment (ECDA) Implementation Protocol	
NACE MR0175	Materials for Use in H ₂ S-Containing Environments in Oil and Gas Production	§192.53 §192.475

1.9 CORROSION RELATED (Continued)		
NACE RP0175	Control of Internal Corrosion in Steel Pipelines and Piping Systems (Revised 1975; Discontinued)	§192.475
NACE SP0106	Control of Internal Corrosion in Steel Pipelines and Piping Systems	§192.476 §192.917
NACE SP0113	Pipeline Integrity Method Selection	§192.925
NACE SP0169	Control of External Corrosion on Underground or Submerged Metallic Piping Systems	§192.453 §192.455 §192.461 §192.463 §192.473 §192.620 App. D
NACE SP0177	Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems	§192.467
NACE SP0188	Discontinuity (Holiday) Testing of New Protective Coatings on Conductive Substrates	§192.461
NACE SP0192	Monitoring Corrosion in Oil and Gas Production with Iron Counts	§192.475 §192.917
NACE SP0200	Steel-Cased Pipeline Practices	§192.323 §192.467
NACE SP0204	Stress Corrosion Cracking (SCC) Direct Assessment Methodology	§192.613 §192.917 §192.929
NACE SP0206	Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)	§192.476 §192.927
NACE SP0207	Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipelines	§192.925 §192.941
NACE SP0274	High-Voltage Electrical Inspection of Pipeline Coatings	§192.461
NACE SP0375	Field-Applied Underground Wax Coating Systems for Underground Pipelines: Application, Performance, and Quality Control	§192.461
NACE SP0394	Application, Performance, and Quality Control of Plant-Applied Single Layer Fusion-Bonded Epoxy External Pipe Coating	§192.461

NACE SP0490	Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coating of 250 to 760 μm (10 to 30 mil)	§192.461
NACE SP0775	Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations	§192.475
NACE TM0109	Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition	§192.467 §192.925 §192.941
NACE TM0194	Field Monitoring of Bacterial Growth in Oilfield Systems	§192.475

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1.9 CORROSION RELATED (Continued)		
NACE TM0497	Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems	§192.467 §192.925
NACE 3D170	Technical Committee Report, Electrical and Electrochemical Methods for Determining Corrosion Rates (Revised 1984; Withdrawn 1994)	§192.475
NACE 3T199	Techniques for Monitoring Corrosion and Related Parameters in Field Applications	§192.476
NACE 35100	In-Line Inspection of Pipelines	GMA G-192-14
NACE 35103	External Stress Corrosion Cracking of Underground Pipelines	§192.613 §192.929
PRCI L52043 / PR-273-0328	SCC Initiation Susceptibility Ranking/Screening	§192.929
SSPC Painting Manual	Good Painting Practice - Volume 1; and Systems and Specifications - Volume 2	§192.479
1.10 DIMENSIONAL STANDARDS		
API Spec 5B	Threading, Gauging, and Thread Inspection of Casing, Tubing, and Line Pipe Threads	
ASME B1.20.1	Pipe Threads, General Purpose, Inch	§192.273
ASME B1.20.3	Dryseal Pipe Threads, Inch	
1.11 PLASTIC RELATED		
AGA XR0603	Plastic Pipe Manual For Gas Service	§192.285 §192.321 §192.751 GMA G-192-15B
API Spec 15HR	Guidelines, High-Pressure Fiberglass Line Pipe	§192.917
ASME I00353	Installation of Plastic Gas Pipeline in Steel Conduits Across Bridges	§192.321
ASTM D696	Test Method for Coefficient of Linear Thermal Expansion of Plastics Between -30 °C and 30 °C With a Vitreous Silica Dilatometer	§192.281
ASTM D2235	Solvent Cement for Acrylonitrile-Butadiene-Styrene (ABS) Plastic Pipe and Fittings	§192.281
ASTM D2560	Solvent Cements for Cellulose Acetate Butyrate (CAB) Plastic Pipe, Tubing and Fittings (Withdrawn 1986)	§192.281

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1.11 PLASTIC RELATED (Continued)		
ASTM D2837	Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products	§192.3 §192.63 §192.121
ASTM D2855	Two-Step (Primer and Solvent Cement) Method of Joining Poly (Vinyl Chloride) (PVC) or Chlorinated Poly (Vinyl Chloride) (CPVC) Pipe and Piping Components with Tapered Sockets	§192.281
ASTM F689	Determination of the Temperature of Above-Ground Plastic Gas Pressure Pipe Within Metallic Casings (Withdrawn 2017)	
ASTM F1041	Guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing	§192.321
ASTM F1290	Electrofusion Joining Polyolefin Pipe and Fittings	§192.281
ASTM F1563	Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing	§192.321
ASTM F1804	Standard Practice for Determining Allowable Tensile Load for Polyethylene (PE) Gas Pipe During Pull-in Installation	GMA G-192-15B
ASTM F1962	Standard Guide for Use of Maxi-Horizontal Directional Drilling for Placement of Polyethylene Pipe or Conduit Under Obstacles, Including River Crossings	GMA G-192-15B
ASTM F2620	Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings	§192.281
GRI-92/0147.1	Users' Guide on Squeeze-Off of Polyethylene Gas Pipes	§192.321
GRI-94/0205	Guidelines and Technical Reference on Gas Flow Shut-Off in Polyethylene Pipes Using Squeeze Tools	§192.321
GRI-96/0194	Service Effects of Hydrocarbons on Fusion and Mechanical Performance of Polyethylene Gas Distribution Piping	§192.123
PPI - Handbook of PE Pipe	<i>Note:</i> The following are available as individual chapters of the PPI Handbook of Polyethylene Pipe:	
	Chapter 8 – Above-Ground Applications for Polyethylene Pipe	§192.321
	Chapter 12 – Horizontal Directional Drilling	GMA G-192-15B

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1.11 PLASTIC RELATED (Continued)		
PPI TN-13	General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings	§192.281 §192.283
PPI TR-9	Recommended Design Factors and Design Coefficients for Thermoplastic Pressure Pipe	§192.123
PPI TR-22	Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases	§192.121 §192.123
PPI TR-33	Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe	§192.281 §192.283
PPI TR-41	Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping	§192.123 §192.281 §192.283
PPI TR-45	Butt Fusion Joining Procedure for Field Joining of Polyamide-11 (PA-11) Pipe	§192.281
PPI TR-50	Generic Butt Fusion Joining Procedure for Field Joining of Polyamide-12 (PA12) Pipe	§192.281
1.12 PRESSURE & FLOW DEVICES		
API RP 520 P2	Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part 2 Installation	§192.201
API RP 525	Testing Procedure for Pressure-Relieving Devices Discharging Against Variable Back Pressure (Revised 1960; Discontinued)	§192.743
ASTM F1802	Test Method for Performance Testing of Excess Flow Valves	§192.381
ASTM F2138	Standard Specification for Excess Flow Valves for Natural Gas Service	§192.381
MSS SP-115	Excess Flow Valves, NPS 1 1/4 and smaller, for Fuel Gas Service	§192.381
MSS SP-142	Excess Flow Valves for Fuel Gas Service, NPS 1½ through 12	§192.381
NBBI	Relieving Capacities of Safety Valves and Relief Valves Approved by the National Board (Discontinued)	§192.201

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1.13 STRUCTURAL STEEL & SUPPORTS		
ASTM A36	Carbon Structural Steel	
MSS SP-58	Pipe Hangers and Supports - Materials, Design, Manufacture, Selection, Application, and Installation	§192.357

Table Continued

1.14 OTHER DOCUMENTS (Continued)		
AGA X69804	Historical Collection of Natural Gas Pipeline Safety Regulations [Available from GPTC Secretary at AGA.]	Foreword Editorial Notes
AGA XK1801	Purging Manual	§192.629 §192.727
AGA XL0702	Distribution Pipe: Repair and Replacement Decision Manual	§192.465 §192.703 GMA G-192-18
AGA XL1001	Classification of Locations for Electrical Installations in Gas Utility Areas	§192.163
AGA XQ0005	Odorization Manual	§192.625
API Bulletin 5A2	Bulletin on Thread Compounds for Casing, Tubing, and Line Pipe	§192.12
API Bulletin E3	Well Abandonment and Inactive Well Practices	§192.12
API Guidance Document HF1	Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines	§192.12
API Guidance Document HF2	Water Management Associated with Hydraulic Fracturing	§192.12
API Guidance Document HF3	Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing	§192.12
API RP 5A3	Recommended Practice on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements	§192.12
API RP 5A5	Field Inspection of New Casing, Tubing, and Plain-end Drill Pipe	§192.12
API RP 5B1	Gauging and Inspection of Casing, Tubing and Line Pipe Threads	§192.12
API RP 5C1	Recommended Practice for Care and Use of Casing and Tubing	§192.12
API RP 10D-2	Recommended Practice for Centralizer Placement and Stop-collar Testing	§192.12
API RP 10F	Recommended Practice for Performance Testing of Cementing Float Equipment	§192.12
API RP 13D	Rheology and Hydraulics of Oil-well Drilling Fluids	
API RP 14B	Design, Installation, Repair and Operation of Subsurface Safety Valve Systems	§192.12
API RP 14E	Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems	§192.12

1.14 OTHER DOCUMENTS (Continued)		
API RP 49	Recommended Practice for Drilling and Well Servicing Operations Involving Hydrogen Sulfide	§192.12
API RP 5MT	Pipeline Inspection Documents for Material Traceability and Electronic Test Reports	§192.67
API RP 51R	Environmental Protection for Onshore Oil and Gas Production Operations and Leases	§192.12
API RP 53	Recommended Practices for Blowout Prevention Equipment Systems for Drilling Wells	§192.12
API RP 54	Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations	§192.12
API RP 76	Contractor Safety Management for Oil and Gas Drilling and Production Operations	§192.12
API RP 500	Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class 1, Division 1 and Division 2	§192.163
API RP 584	Integrity Operating Windows	GMA G-192-3
API RP 754	Process Safety Performance Indicators for the Refining and Petrochemical Industries	GMA G-192-3
API RP 1102	Steel Pipelines Crossing Railroads and Highways	§192.103 GMA G-192-15
API RP 1114	Recommended Practice for the Design of Solution-Mined Underground Storage Facilities	§192.12
API RP 1115	Design and Operation of Solution-mined Salt Caverns Used for Liquid Hydrocarbon Storage	§192.12
API RP 1117	Movement of In-Service Pipelines	§192.103, §192.703
API RP 1166	Excavation Monitoring and Observation	§192.614
API RP 1168	Pipeline Control Room Management	§192.631
API RP 1173	Pipeline Safety Management Systems	GMA G-192-3
API Spec 5CT	Specification for Casing and Tubing	§192.12
API Spec 5DP	Specification for Drill Pipe	§192.12
API Spec 6A	Specification for Wellhead and Christmas Tree Equipment	§192.12
API Spec 10A	Specification for Cements and Materials for Well Cementing	§192.12
API Spec 14A	Specification for Subsurface Safety Valve Equipment	§192.12
API Std 65-2	Isolating Potential Flow Zones during Well Construction	§192.12

1.14 OTHER DOCUMENTS (Continued)		
API Std 1163	In-Line Inspection Systems Qualification Standard	GMA G-192-14
API Tech Report 5C3	Calculating Performance Properties of Pipe Used as Casing or Tubing	§192.12
API Tech Report 10TR1	Cement Sheath Evaluation	§192.12
API Tech Report 10TR3	Technical Report on Temperatures for API Cement Operating Thickening Time Tests	§192.12
API Tech Report 10TR4	Selection of Centralizers for Primary Cementing Operations	§192.12
API 579	Fitness-for-Service	§192.624
AREMA	Manual for Railway Engineering, Chapter 1 – Roadway and Ballast (for Part 5 – Pipelines)	GMA G-192-15
ASCE 428-5	Guidelines for the Seismic Design of Oil and Gas Pipeline Systems (Discontinued)	§192.103
ASME B31.1	Power Piping	§192.141
ASME B31.2	Fuel Gas Piping (Withdrawn 1988; Replaced by NFPA 54/ANSI Z223.1)	
ASME B31.3	Process Piping	§192.141 §192.159
ASME B31.4	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids	
ASME B31.5	Refrigeration Piping and Heat Transfer Components	§192.141
ASME B31.8S-2010	Managing System Integrity of Gas Pipelines	§192.929
ASME B31.9	Building Services Piping	
ASME B31Q	Pipeline Personnel Qualification	§192.805
ASME CRTD Vol. 57	Determining the Yield Strength of In-Service Pipe	§192.107
ASME CRTD-91	Applications Guide for Determining the Yield Strength of In-Service Pipe by Hardness Evaluation	§192.107
ASME Guide SI-1	ASME Orientation and Guide for Use of SI (Metric) Units	GMA G-192-M
ASNT ILI-PQ	In-line Inspection Personnel Qualification and Certification	GMA G-192-14
ASTM C150/C150M	Standard Specification for Portland Cement	§192.12

1.14 OTHER DOCUMENTS (Continued)		
ASTM D1586	Standard Test Method for Standard Penetration Test (SPT) and Split-Barrel Sampling of Soils	GMA G-192-15A
ASTM D2487	Standard Practice for Classification of Soils for Engineering Purposes (Unified Soil Classification System)	GMA G-192-15A
ASTM D2774	Standard Practice for Underground Installation of Thermoplastic Pressure Piping	§192.321
ASTM D3740	Standard Practice for Minimum Requirements for Agencies Engaged in Testing and/or Inspection of Soil and Rock as Used in Engineering Design and Construction	§192.12
ASTM D3967	Standard Test Method for Splitting Tensile Strength of Intact Rock Core Specimens	§192.12
ASTM D4543	Standard Practices for Preparing Rock Core as Cylindrical Test Specimens and Verifying Conformance to Dimensional and Shape Tolerances	§192.12
ASTM D4645	Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method	§192.12
ASTM D6273	Standard Test Methods for Natural Gas Odor Intensity	§192.625
ASTM D7012	Standard Test Methods for Compressive Strength and Elastic Moduli of Intact Rock Core Specimens under Varying States of Stress and Temperatures	§192.12
ASTM D7070	Standard Test Methods for Creep of Rock Core Under Constant Stress and Temperature	§192.12
ASTM E84	Test Method for Surface Burning Characteristics of Building Materials	§192.163
AWS A3.0	Standard Welding Terms and Definitions	§192.3 §192.221
CGA	"Best Practices" Guide	§192.325 §192.361 §192.614
	One Call Systems International (OCSI) Resource Guide	§192.614
CoGDEM	Gas Detection and Calibration Guide	GMA G-192-11 GMA G-192-11A
GRI-91/0283	Guidelines for Pipelines Crossing Railroads	§192.103 GMA G-192-15
GRI-91/0284	Guidelines for Pipelines Crossing Highways	§192.103 GMA G-192-15
GRI-91/0285	Technical Summary and Database for Guidelines for Pipelines Crossing Railroads and Highways	GMA G-192-15

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

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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
PRCI PR-430-153706-R01	Hydrostatic Test Guidelines for Integrity Management	GMA G-192-9A
UL 723	Test for Surface Burning Characteristics of Building Materials	§192.163

2 GOVERNMENTAL DOCUMENTS

- Note: NTSB Reports are available at <https://www.ntsb.gov/investigations/AccidentReports/Pages/Reports.aspx?mode=Pipeline>
OPS Advisory Bulletins and Alert Notices are accessible as follows.
- PHMSA-OPS website at www.phmsa.dot.gov/regulations-fr/notices
 - Federal Register (FR) at <https://www.gpo.gov/fdsys/search/submitcitation.action?publication=FR> or at www.federalregister.gov/documents/search#

BSEE Report RLS011	Cement Plug Testing: Weight vs pressure Testing to Assess Viability of a Wellbore Seal between Zones	§192.12
DHS	Recommended Practice: Improving Industrial Control System Cybersecurity with Defense-in-Depth Strategies. Industrial Control Systems Cyber Emergency Response Team (September 2016).	§192.631
DOT & DOI - MOU	Memorandum of Understanding Between DOT and DOI Regarding Outer Continental Shelf Pipelines	§191.1 §192.1 GMA G-192-19
NAPSR	Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels Compared to Code of Federal Regulations	§191.1 §192.1
NEB MH-2-95	Stress Corrosion Cracking on Canadian Oil and Gas Pipelines, Report of the Inquiry, National Energy Board, December 1996	§192.613 §192.929
NTSB Report MAR-21-05	Marine Accident Report - Hazardous Liquid Pipeline Strike and Subsequent Explosion and Fire aboard Dredging Vessel <i>Waymon Boyd</i> , Corpus Christi, Texas, August 21, 2020	GMA G-192-13
NTSB Report PAB-98-02	Pipeline Accident Brief – Fire and Explosion, Midwest Gas Company, Waterloo, Iowa, October 17, 1994	§192.613
NTSB Report SIR-98-01	Special Investigation Report – Brittle-Like Cracking in Plastic Pipe for Gas Service	§192.613
OPS ADB-03-03	Advisory Bulletin – Identified Sites for Possible Inclusion as High Consequence Areas (HCAs) in Gas Integrity Management Programs (68 FR 42458, July 17, 2003)	§192.905
OPS ADB-03-05	Advisory Bulletin – Stress Corrosion Cracking (SCC) Threat to Gas and Hazardous Liquid Pipelines (68 FR 58166, Oct. 8, 2003)	§192.613 §192.929
OPS ADB-04-01	Advisory Bulletin – Hazards Associated with De-Watering of Pipelines (69 FR 58225, Sept. 29, 2004)	§192.515
OPS ADB-06-01	Advisory Bulletin – Notification on Safe Excavation Practices and the use of Qualified Personnel to oversee all Excavations and Backfilling Operations (71 FR 2613, Jan. 17, 2006)	§192.605 §192.614 §192.805

OPS ADB-07-01	Advisory Bulletin – Senior Executive Signature and Certification of Integrity Management Program Performance Reports (72 FR 20175, Apr. 23, 2007)	§192.951
OPS ADB-07-02 [Shown as ADB-07-01 in text]	Advisory Bulletin – Updated Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe (72 FR 51301, Sept. 6, 2007 with Correction, 73 FR 11192, Feb. 29, 2008)	§192.613 §192.917

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2 GOVERNMENTAL DOCUMENTS (Continued)		
OPS ADB-08-02	Advisory Bulletin – Issues Related to Mechanical Couplings Used in Natural Gas Distribution Systems (73 FR 11695, Mar. 4, 2008)	§192.281
OPS ADB-08-03	Advisory Bulletin – Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems (73 FR 12796, Mar. 10, 2008)	§192.616
OPS ADB-09-01	Advisory Bulletin – Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe (74 FR 23930, May 21, 2009)	§192.917
OPS ADB-10-03	Advisory Bulletin – Girth Weld Quality Issues Due to Improper Transitioning, Misalignment, and Welding Practices of Large Diameter Line Pipe (75 FR 14243, Mar. 24, 2010)	§192.620
OPS ADB-10-08	Advisory Bulletin – Emergency Preparedness Communications (75 FR 67807, Nov. 3, 2010)	§192.615
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-86-02	Advisory Bulletin – Plastic Piping, Mechanical Coupling (Feb. 26, 1986; see document at PHMSA-OPS website)	§192.917
OPS ADB-93-01	Advisory Bulletin – Snow Accumulation on Gas Pipeline Facilities (58 FR 7034, Feb. 3, 1993)	§192.616
OPS ADB-97-01	Advisory Bulletin – Potential Damage to Pipelines by Impact of Snowfall, and Actions Taken by Homeowners and Others to Protect Gas Systems from Abnormal Snow Build-up (Issued in Kansas City, MO on Jan. 24, 1997)	§192.616
OPS ADB-99-01	Advisory Bulletin – Susceptibility of Certain Polyethylene Pipe Manufactured by Century Utility Products, Inc. to Premature Failure Due to Brittle-Like Cracking (64 FR 12211, Mar. 11, 1999)	§192.613 §192.917
OPS ADB-99-02	Advisory Bulletin – Potential Susceptibility of Plastic Pipe Installed Between the [Years] 1960 and the Early 1980s to Premature Failure Due to Brittle-Like Cracking (64 FR 12212, Mar. 11, 1999)	§192.613 §192.917

OPS ADB-99-04	Advisory Bulletin – Directional Drilling and Other Trenchless Technology Operations Conducted in Proximity to Underground Pipeline Facilities (64 FR 46967, Aug. 27, 1999)	GMA G-192-15B
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2 GOVERNMENTAL DOCUMENTS (Continued)		
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 – Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe (67 FR 70806, Nov. 26, 2002 with Correction, 67 FR 72027, Dec. 3, 2002)	§192.613 §192.917
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-2016-6	Advisory Bulletin – Safeguarding and Securing Pipelines From Unauthorized Access (81 FR 89183, Dec 9, 2016).	§191.5 §192.179 §192.631
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 ADB-2020-02	Advisory Bulletin – Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems (85 FR 61097, September 29, 2020)	§192.195 §192.605 G-192-8

Addendum 2, February 2023
Addendum 3, July 2023
Addendum 4, May 2024

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
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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
	Frequently Asked Questions (FAQs) on Gas Transmission Final Rule (Docket No. PHMSA-2019-0225, Sept. 15, 2020)	§192.607
	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
	Operator Qualification Guidance Manual for Operators of LP Gas Systems	§192.11 §192.801
	Operator Qualification Guide for Small Distribution Systems	§192.801
Transportation Security Administration	Pipeline Security Guidelines (March 2018) (https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf)	§191.5 §192.631

Table Continued

3 TECHNICAL PAPERS & PUBLICATIONS

3.1 EMERGENCY RELATED	
(Reserved)	
3.2 CORROSION RELATED	
"Evaluation of Chemical Treatments in Natural Gas System vs. MIC and Other Forms of Internal Corrosion Using Carbon Steel Coupons," Timothy Zintel, Derek Kostuck, and Bruce Cookingham, Paper # 03574 presented at CORROSION/03 San Diego, CA	§192.475
"Field Guide for Investigating Internal Corrosion of Pipelines," Richard Eckert, NACE International, 2003	§192.475 §192.917
"Field Use Proves Program for Managing Internal Corrosion in Wet-Gas Systems," Richard Eckert and Bruce Cookingham, Oil & Gas Journal, January 21, 2002	§192.475
"Improvement of External Corrosion Direct Assessment Methodology by Incorporating Soils Data," https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=118	§192.917
"Internal Corrosion Direct Assessment," Oliver Moghissi, Bruce Cookingham, Lee Norris, and Phil Dusek, Paper # 02087 presented at CORROSION/02 Denver, CO	§192.475
"Internal Corrosion Direct Assessment of Gas Transmission Pipeline – Application," Oliver Moghissi, Laurie Perry, Bruce Cookingham, and Narasi Sridhar, Paper # 03204 presented at CORROSION/03 San Diego, CA	§192.475
"Microscopic Differentiation of Internal Corrosion Initiation Mechanisms in a Natural Gas System," Richard Eckert, Henry Aldrich, and Chris Edwards, Bruce Cookingham, Paper # 03544 presented at CORROSION/03 San Diego, CA	§192.475
"SCC Detection and Mitigation Based on In-Line Inspection Tools," W. Kresic and S. Ironside, Paper # IPC2004-0375 presented at ASME International Pipeline Conference, Calgary, October 2004.	§192.613
3.3 PLASTIC RELATED	
"An Evaluation of Polyamide 11 for Use in High Pressure/High Temperature Gas Piping Systems," T.J. Pitzl et al., 15th Plastic Fuel Gas Pipe Symposium Proceedings – 1997, p. 107	§192.123
"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 GPTC website	§192.613
"Effect of Elevated Ground Temperature (from Electric Cables) on the Pressure Rating of PE Pipe in Gas Piping Applications," E.F. Palermo, Ph.D., AGA Operations Conference, April 2007, available at GPTC website	§192.361

Table Continued

3.3 PLASTIC RELATED (Continued)	
"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	§192.123
Plastic Pipe Database Committee (PPDC) reports, https://www.aga.org/safety/promoting-safety/plastic-pipe-database-collection-initiative/	§192.917
"Polyamide 11 Liners Withstand Hydrocarbons, High Temperature," A. Berry, Pipeline & Gas Journal, December 1998, p. 81	§192.123
"Prediction of Organic Chemical Permeation through PVC Pipe," A.R. Berens, Research Technology, November 1985, p. 57	§192.123
"Second Generation Skinned Pipes with Enhanced Fracture Resistance," Jeremy Bowman, Uponor UK, Plastics Pipes XIII, 2006	GMA G-192-15B
"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	§192.123
3.4 UNCASED PIPE AND DIRECTIONAL DRILLING RELATED	
"Considerations for the Installation of Polyethylene Water Pipe by 'Horizontal Directional Drilling,' Larry Petroff, Performance Pipe, presented at Annual Conference and Exposition of AWWA, 2006	GMA G-192-15B
"Directional Drilling Damage Prevention Guidelines for the Natural Gas Industry," AGA Engineering Technical Note (no catalog number), 2004	GMA G-192-15B
"Guidelines For A Successful Directional Crossing Bid Package," Directional Crossing Contractors Association, 1995	GMA G-192-15A GMA G-192-15B
"Horizontal Directional Drilling Good Practices Guidelines" - 2008 (3rd Edition), North American Society for Trenchless Technology (NASTT).	GMA G-192-15A GMA G-192-15B
"Piping Handbook," Fourth Edition, J.H. Walker and Sabin Crocker, 1930, McGraw-Hill Inc., New York, NY; data re-affirmed in Sixth Edition, published 1992	GMA G-192-15
"Proceedings of the International No-Dig Conferences," sponsored by the International Society for Trenchless Technology (ISTT) and the North American Society for Trenchless Technology (NASTT), 1988, 1991-1996	GMA G-192-15B
3.5 SAFETY AND INTEGRITY MANAGEMENT RELATED	
"Dealing with Low-Frequency-Welded ERW Pipe and Flashwelded Pipe with Respect to HCA-Related Integrity Assessments," John F. Kiefner, 2002, www.kiefner.com.	§192.917
"Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines," Final Report 05-12R, John F. Keifner, 2007, http://primis.phmsa.dot.gov/gasimp/docs/Evaluating_Stability_of_Defects.pdf .	§192.917
"Guideline for Assessing the Performance of Oil and Natural Gas Pipeline Systems in Natural Hazard and Human Threat Events," American Lifelines Alliance.	§192.917

Coastal and Marine Operators' Pipeline Industry Initiative (https://www.camogroup.org/)	§192.614 GMA G-192-13
Recommended Best Practice Guide for Safe Dredging near Underwater Gas and Liquid Pipelines, Council for Dredging and Marine Construction Safety (https://cdmcs.org/)	§192.614 GMA G-192-13

Table Continued

3.5 SAFETY AND INTEGRITY MANAGEMENT RELATED (Continued)	
"Improving the Safety of Marine Pipelines," National Research Council Report / National Academies Press (NAP) – 1994	GMA G-192-13
"Integrity Characteristics of Vintage Pipelines," INGAA	§192.917
"Pipeline Risk Management Manual," W. Kent Muhlbauer, Gulf Publishing Company, ISBN: 0750675799	§192.12 §192.917
"Results of State Damage Prevention Program Characterizations," http://primis.phmsa.dot.gov/comm/sdppc.htm?nocache=2189 .	§192.917
"Review of Integrity Management for Natural Gas Transmission Pipelines," ANSI Technical Report No. ANSI-GPTC-Z380-TR-1, November 18, 2001 (Withdrawn 3/30/12); AGA Catalog Number X69806, available at GPTC website.	§192.907 §192.917
3.6 GENERAL	
"Pipeline Rules of Thumb Handbook," E. W. McAllister, Gulf Publishing Company, ISBN: 9780123876935	GMA G-191-9

4 PUBLISHING ORGANIZATIONS

The specifications, codes, standards, and other documents listed in Sections 1 and 2 are published by the following organizations:

AGA	American Gas Association 400 North Capitol Street, NW, 4 th Floor Washington, DC 20001 Phone: 202.824.7000 Fax: 734.780.8000 On line: www.aga.org/GPTC	Publications: See Techstreet 800.699.9277
ANSI	American National Standards Institute 25 West 43 rd Street, 4 th Floor New York, NY 10036 Phone: 212.642.4900 Fax: 212.398.0023 On line: www.ansi.org	
API	American Petroleum Institute 1220 L Street, NW Washington, D.C. 20005-4070 Phone: 202.682.8000 Fax: 202.682.8154 On line: www.api.org	Publications: See IHS Markit or See Techstreet
AREMA	American Railway Engineering and Maintenance-of-Way Association 4501 Forbes Blvd, Suite 130 Lanham, MD 20706 Phone: 301.459.3200	

Fax: 301.459.8077
On line: www.arena.org

ASCE The American Society of Civil Engineers
1801 Alexander Bell Drive
Reston, VA 20191-4400
Phone: 800.548.2723
Fax: 703.295.6333
On line: www.asce.org

ASME The American Society of Mechanical Engineers International
New Jersey Service Center
150 Clove Road
Little Falls, NJ 07424-2100
Phone: 800.843.2763
Fax: 973.882.1717
On line: www.asme.org

ASNT American Society for Nondestructive Testing
P.O. Box 28518
1711 Arlingate Lane
Columbus, OH 43228-0518
Phone: 800.222.2768
Fax: 614.274.6899
On line: www.asnt.org

ASTM ASTM International (formerly American Society for Testing and Materials)
100 Barr Harbor Drive
West Conshohocken, PA 19428-2959
Phone: 877.909.2786
Fax: 610.832.9555
On line: www.astm.org

AWS American Welding Society
8669 NW 36 Street, #130
Miami, FL 33166-6672
Phone: 305.443.9353 800.443.9353
Fax: 305.443.5951
On line: www.aws.org

AWWA American Water Works Association
6666 W. Quincy Avenue
Denver, CO 80235
Phone: 303.794.7711 800.926.7337
Fax: 303.347.0804
On line: www.awwa.org

BSEE Bureau of Safety and Environmental Enforcement
1849 C Street, NW
Washington, D.C. 20240
Phone: 202-208-4378
On line: www.bsee.gov

Canadian NEB	Canadian National Energy Board 517 Tenth Avenue SW Calgary, Alberta, Canada T2R 0A8 Phone: 800.899.1265 Fax: 877.288.8803 On line: www.neb.gc.ca	
CEPA	Canadian Energy Pipeline Association Suite 200, 505-3rd St. SW Calgary, Alberta, Canada T2P 3E6 Phone: 403.221.8777 Fax: 403.221.8760 On line: www.cepa.com	
CGA	Common Ground Alliance 707 Prince Street Arlington, VA 22314 Phone: 703.836.1709 Fax: 309.407.2244 On line: www.commongroundalliance.com	Free download: "Best Practices" Guide Available at CGA website
CoGDEM	The Council of Gas Detection and Environmental Monitoring Unit 9, Knowl Piece Business Centre Knowl Piece, Wilbury Way Hitchin, Herts, SG4 0TY, UK Phone: +44 1462 434322 Fax: +44 1462 434488 On line: www.cogdem.org.uk	
DHS	Mail Operations Program Manager MGMT/CRSO/Mailstop 0075 Department of Homeland Security 245 Murray Lane SW Washington, DC 20528-0075	
DIPRA	Ductile Iron Pipe Research Association P.O. Box 19206 Golden, CO 80402 Phone: 205.402.8700 On line: www.dipra.org	
GTI (formerly GRI)	Gas Technology Institute 1700 S. Mount Prospect Road Des Plaines, IL 60018-1804 Phone: 847.768.0500 Fax: 847.768.0501 On line: www.gastechnology.org	
IAPMO	International Association of Plumbing and Mechanical Officials 4755 E. Philadelphia Street Ontario, CA 91761 Phone: 909.472.4100 Orders: 800.854.2766 Fax: 909.472.4232	

On line: www.iapmo.org

ISO	International Organization for Standardization 1214 Vernier Geneva, Switzerland Phone: +41 22 749 01 11 On line: www.iso.org
MSS	Manufacturers Standardization Society [of the Valve and Fittings Industry] 127 Park Street, NE Vienna, VA 22180-4602 Phone: 703.281.6613 Fax: 703.281.6671 On line: msshq.org
NACE	NACE International 15835 Park Ten Place Houston, TX 77084-4906 Phone: 281.228.6200 800.797.6223 Fax: 281.228.6300 On line: www.nace.org
NBBI	National Board of Boiler and Pressure Vessel Inspectors 1055 Crupper Avenue Columbus, Ohio 43229-1183 Phone: 614.888.8320 Fax: 614.888.0750 On line: www.nationalboard.org
NCB	National Coal Board (replaced by The Coal Authority in 1994) The Coal Authority 200 Lichfield Lane Mansfield, Nottinghamshire NG18 4RG Phone: 0345.762.6848 On line: www.coal.gov.uk
NFPA	National Fire Protection Association 1 Batterymarch Park Quincy, MA 02169-7471 Phone: 800.344.3555 Fax: 800.593.6372 On line: www.nfpa.org
OPS	Office of Pipeline Safety / PHMSA / DOT East Building, 2 nd Floor 1200 New Jersey Avenue, SE Washington, DC 20590-0001 Phone: 202.366.4595 Fax: 202.366.4566 On line: www.phmsa.dot.gov/pipeline

OTD	Operations Technology Development (Same Address as GTI) 1700 S. Mount Prospect Road Des Plaines, IL 60018 Phone: 847.544.3400 Fax: (None listed) On line: www.otd-co.org
PPI	Plastics Pipe Institute 105 Decker Court, Suite 825 Irving, TX 75062 Phone: 469.499.1044 Fax: 469.499.1063 On line: www.plasticpipe.org
PRCI	Pipeline Research Council International 15059 Conference Center Drive, Suite 130 Chantilly, VA 20151 Phone: 703.205.1600 Fax: 703.205.1607 On line: www.prci.org
SSPC	The Society for Protective Coatings (formerly Steel Structures Painting Council) 800 Trumbull Drive Pittsburgh, PA 15205 Phone: 877.281.7772 Fax: 412.281.9992 On line: www.sspc.org
UL	Underwriters Laboratories 2600 N.W. Lake Road Camas, WA 98607-8542 Phone: 877.854.3577 Fax: 847.272.8129 On line: www.ul.com

5 ADDITIONAL INFORMATION RESOURCES

ACGIH	American Conference of Governmental Industrial Hygienists 1330 Kemper Meadow Drive Cincinnati, Ohio 45240 Phone: 513.742.2020 Fax: 513.742.3355 On line: www.ACGIH.org
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. 1791 Tullie Circle, NE Atlanta, GA 30329 Phone: 404.636.8400 Fax: 404.321.5478 On line: www.ashrae.com

- Battelle** Battelle
505 King Avenue
Columbus, OH 43201-2693
Phone: 800.201.2011
Fax: 614.456.5017
On line: www.battelle.org
- Federal Register** U.S. Government Printing Office
732 North Capitol Street, NW, mailstop IDCC
Washington, DC 20401-0001
Phone: 202.512.1800 866.512.1800
Fax: 202.512.2104
On line - General: www.federalregister.gov/documents/search
Specific Citation: [ww.gpo.gov/fdsys/search/submitcitation.action?publication=FR](http://www.gpo.gov/fdsys/search/submitcitation.action?publication=FR)
- FEMA** Federal Emergency Management Agency
500 C Street, SW
Washington, DC 20472
Phone: 800.621.FEMA (3362)
Fax: 202.646.2500 800.827.8112
On line: www.fema.gov
- Gulf** Gulf Publishing Company
2 Greenway Plaza, Suite 1020
Houston, Texas 77046
Phone: 713.529.4301
Fax: 713.520.4433
On line: www.gulfpub.com
- ICC (formerly BOCA)** International Codes Council
500 New Jersey Avenue, NW, 6th Floor
Washington, DC 20001-2070
Phone: 888.422.7233
Fax: 202.783.2348
On line: www.iccsafe.org
- IHS** IHS Markit
15 Inverness Way East
Englewood, CO 80112
Phone: 303.397.7956 800.854.7179
On line: <https://ihsmarkit.com/index.html>
- NAP** National Research Council / National Academies Press (NAP)
500 Fifth Street, NW, Publications:
Washington, DC 20001 Free PDF download
Phone: 800.624.6242
Fax: 202.334.2451
On line: www.nap.edu

- NTIS National Technical Information Service
U.S. Department of Commerce
5301 Shawnee Road
Alexandria, VA 22312
Phone: 703.605.6000 800.553.6847
Fax: 703.605.6900
On line: www.ntis.gov
- NTSB National Transportation Safety Board
490 L'Enfant Plaza, SW
Washington, DC 20594
Phone: 202.314.6000 800.877.6799
Fax: 202.314.6132
On line: www.nts.gov
- SAI SAI Global (formerly ILI Infodisk, Inc.)
(formerly 610 Winters Avenue
ILI) Paramus, NJ 07652
Phone: 201.986.1131 800.374.3818
Fax: 201.986.7886
On line: <https://www.saiglobal.com/>
- Publication Sales:
Phone: 888.454.2688
- Techstreet Techstreet
3025 Boardwalk Drive, Suite 220
Ann Arbor, MI 48108
Phone: 734.780.8000 800.699.9277
Fax: 734.780.2046
On line: www.techstreet.com
- TTI Technical Toolboxes, Inc.
3801 Kirby Drive, Suite 520
P.O. Box 980550
Houston, TX 77098-0550
Phone: 713.630.0505 866.866.6766
Fax: 713.630.0560
On line: <https://technicaltoolboxes.com/>
- U.S. Gov U.S. Government Printing Office
Printing 732 North Capitol Street, NW
Washington, DC 20401-0001
Phone: 202.512.1800 866.512.1800
Fax: 202.512.2104
On line: www.gpo.gov

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6 SUMMARY OF PRIMARY WEBSITES

Site Reference	Website Link	Guide Location
ACGIH website	www.acgih.org	GMA G-192-1
AGA website	www.aga.org	§192.361 §192.613 GMA G-192-1
ANSI website	www.ansi.org	GMA G-192-1
API Spec 5L Comparison	www.api.org/~media/files/certification/monogram-apiqr/program-updates/2008_08_13_wg4208_5l_43_44_comparison.pdf?la=en	§192.7
API website	www.api.org	GMA G-192-1
ASCE website	www.asce.org	GMA G-192-1
ASHRAE website	www.ashrae.com	GMA G-192-1
ASME website	www.asme.org	GMA G-192-1
ASTM website	www.astm.org	GMA G-192-1
AWS website	www.aws.org	GMA G-192-1
AWWA website	www.awwa.org	GMA G-192-1
Battelle website	www.battelle.org	GMA G-192-1
Canadian National Energy Board (NEB)	www.neb.gc.ca	GMA G-192-1
CGA websites	https://commongroundalliance.com https://commongroundalliance.com/map https://commongroundalliance.com/best-practices-guide	§192.325 §192.361 §192.614
CoGDEM website	www.cogdem.org.uk	GMA G-192-1
DIPRA website	www.dipra.org	GMA G-192-1
Federal Prisons	www.bop.gov	§192.905
Federal Register website	General: www.federalregister.gov/documents/search# Specific Citation: www.gpo.gov/fdsys/search/submitcitation.action?publication=FR	GMA G-192-1
FEMA homepage	www.fema.gov	§192.615

Table Continued

Site Reference (Continued)	Website Link	Guide Location
FEMA ICS overview	training.fema.gov/emiweb/is/icsresource	§192.615
GPTC website (for Technical Papers)	www.aga.org/GPTC	§192.361 §192.613 §192.907 GMA G-192-1
GTI website	www.gastechnology.org	GMA G-192-1
Hospitals	http://allhospitals.org	§192.905
IAPMO website	www.iapmo.org	GMA G-192-1
ICC (or BOCA) website	www.iccsafe.org	GMA G-192-1
IHS Markit website	www.ihsmarkit.com	GMA G-192-1
ILI Infodisk (SAI Global) website	https://www.saiglobal.com/	GMA G-192-1
MSS website	www.mss-hq.org	GMA G-192-1
NACE website	https://www.ampp.org/home	GMA G-192-1
NAP website	www.nap.edu or www.nap.edu/read/2347	GMA G-192-1 GMA G-192-13
NAPSR website	www.napsr.org	§191.1 §192.1 §192.18 §192.909
National Parks	www.recreation.gov	§192.905
NBBI website	www.nationalboard.org	GMA G-192-1
NCB website	www.coal.gov.uk	GMA G-192-1
NFPA website	www.nfpa.org	GMA G-192-1
NRC pipeline reports website	https://nrc.uscg.mil/Default.aspx	§191.5
NTIS website	www.ntis.gov	GMA G-192-1
NTSB reports	https://www.nts.gov/investigations/AccidentReports/Pages/Reports.aspx?mode=Pipeline or www.nts.gov/safety/safety-studies/Pages/SafetyStudies.aspx	§192.613
NTSB website	www.nts.gov	GMA G-192-1
OPS Advisory Bulletins via FR	www.gpo.gov/fdsys/search/submitcitation.action?publication=FR	§192.905 GMA G-192-1
OPS Home Page	www.phmsa.dot.gov/pipeline	GMA G-192-1

Table Continued

Site Reference (Continued)	Website Link	Guide Location
OPS Information Resource Manager Email	InformationResourcesManager@phmsa.dot.gov	§192.727
OPS Integrity Management Database	primis.phmsa.dot.gov/gasimp	§192.907 §192.911
OPS NPMS homepage	www.npms.phmsa.dot.gov	§192.727
OPS Public Education	primis.phmsa.dot.gov/comm/PublicEducation.htm	§192.616
PHMSA-OPS Annual Report Data	www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids	GMA G-192-8
PHMSA-OPS Guidance Manuals	www.phmsa.dot.gov/training/pipeline/guidance-manuals	§192.1 §192.11 §192.616 §192.801 GMA G-192-8
<u>PHMSA-OPS Guidance for Program Evaluation</u>	www.regulations.gov/document?D=PHMSA-2014-0086-0002 <i>{then open the attachment}</i>	GMA G-192-3
PHMSA-OPS Guidance for Small DIMP	https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/gas-distribution-integrity-management/66011/phmsadimpsmalloperatorguidancerev1022813.pdf	GMA G-192-8
PHMSA-OPS Report Forms and Instructions	https://www.phmsa.dot.gov/forms/pipeline-forms	§191.9 §191.11 §191.15 §191.17 §192.945 GMA G-191-2 GMA G-192-8
PPI website	www.plasticpipe.org	GMA G-192-1
PRCI website	www.prci.org	GMA G-192-1
SSPC website	www.sspc.org	GMA G-192-1
TTI website	https://technicaltoolboxes.com/	GMA G-192-1
UL website	www.ul.com	GMA G-192-1
US Government Publications	www.gpo.gov	GMA G-192-1
Department of Homeland Security (DHS)'s National Cybersecurity and Communications Integration Center (NCCIC) and Industrial Control Systems Cyber Emergency Response Team (ICS-CERT)	http://ics-cert.us-cert.gov/sites/default/files/recommended_practices/NCCIC_ICS-CERT_Defense_in_Depth_2016_S508C.pdf	§192.631

Department of Homeland Security	www.cisa.gov/connect-plan-train-report	§191.613
Transportation Security Administration	https://www.tsa.gov/sites/default/files/pipeline_security_guidelines.pdf	§191.5 §192.631
Coastal and Marine Operators' Pipeline Industry Initiative	www.camogroup.org	§192.614 GMA G-192-13
Council for Dredging & Marine Construction Safety	https://cdmcs.org	§192.614 GMA G-192-13

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GUIDE MATERIAL APPENDIX G-192-6

(See guide material under §§192.319, 192.321, 192.361, 192.614, and
Guide Material Appendices G-192-13, G-192-15A, and G-192-15B)

SUBSTRUCTURE DAMAGE PREVENTION GUIDELINES FOR DIRECTIONAL DRILLING AND OTHER TRENCHLESS TECHNOLOGIES

1 SCOPE

Damage to existing underground facilities can result from directional drilling or the use of other trenchless technologies. These general guidelines apply to directional drilling and trenchless technologies performed by the operator or a third party in proximity to gas facilities. In part, they provide the following.

- (a) Criteria for planning and precautions.
- (b) Recommended procedures.

2 DAMAGE PREVENTION WHEN INSTALLING FACILITIES

Precautions should be taken when installing gas facilities by directional drilling or other trenchless technologies, which may include the following.

- (a) Using available one-call notification system(s) to have facilities within the immediate area located and marked; and directly contacting known, non-participating utility owners for locations of their facilities.
- (b) Ensuring that known facilities are located and marked prior to commencing work.
- (c) Exposing facilities within the immediate work area by hand excavation before starting a bore if the depths of the facilities are not established by other means.
- (d) Considering sewer systems within the area, which are especially vulnerable to damage from cross bore for the following reasons.
 - (1) Sewer lines are often non-metallic, which make them difficult to locate.
 - (2) Clean-outs or other indications of sewer laterals may be hidden or non-existent.
 - (3) A cross bore condition may not be readily apparent when a sewer, particularly a gravity flow system, is compromised.
- (e) Notifying residences and businesses in the area of impending work.
- (f) Checking local regulations for the minimum separation distances between the new gas piping and the other facilities.
- (g) Making arrangements with local authorities for traffic control, as necessary.
- (h) Ensuring adequate clearance of overhead electric, telephone, or cable lines from construction equipment.
- (i) Reviewing precautions recommended by manufacturers of trenchless technology equipment prior to construction.
- (j) Following applicable state and local requirements for damage prevention.
- (k) Indicating abandoned facilities differently from active facilities to reduce confusion or the likelihood an active facility is mistaken for an abandoned facility.

3 PROTECTING EXISTING GAS FACILITIES

When either an operator or a third party shall excavate near an existing gas facility by directional drilling or using other trenchless technologies, the operator should consider the following.

- (a) Where it is anticipated that the bore will cross an existing facility, or come within a safety zone (as established by the operator or a jurisdictional regulatory agency), expose that facility to determine its precise location to ensure adequate separation between the existing and proposed facilities.
- (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.
- (g) Locating and marking of newly abandoned and other known abandoned facilities to reduce the likelihood an active facility is mistaken for an abandoned facility.

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-192-8

(See §§192.1001, 192.1003, 192.1005, 192.1007, 192.1011, 192.1015, and
Guide Material Appendix G-192-8A)

DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM (DIMP)

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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, 192.1011, 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 facilities¹, 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 problem² 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.

Primary Threat	Threat Subcategories	Questions to Check Subcategory Applicability to System	Extent of Threat		
			General	Local	NA
CORROSION	External corrosion: bare steel pipe (CP or no CP)	<ul style="list-style-type: none"> <input type="radio"/> Does bare steel exist in the system? <input type="radio"/> Is the pipe cathodically protected? <input type="radio"/> Have corrosion leaks occurred? <input type="radio"/> Do exposed pipe inspections indicate external corrosion? <input type="radio"/> Are cathodic protection readings consistently adequate during annual monitoring? <input type="radio"/> Are there known sources of stray electrical currents in the area? 			
	External corrosion: cast iron pipe (graphitization)	<ul style="list-style-type: none"> <input type="radio"/> Does cast iron or ductile iron exist in the system? <input type="radio"/> Have fractures occurred in the pipe, other than those related to excavation activities? <input type="radio"/> Are the fractures limited to certain diameters of pipe? <input type="radio"/> Are there known sources of stray electrical currents in the area? <input type="radio"/> Do exposed pipe inspections indicate external corrosion? 			
	External corrosion: coated and wrapped steel pipe (CP or no CP)	<ul style="list-style-type: none"> <input type="radio"/> Does coated and wrapped steel exist in the system? <input type="radio"/> Is the pipe cathodically protected? <input type="radio"/> Have corrosion leaks occurred? <input type="radio"/> Are there known sources of stray electrical currents in the area? <input type="radio"/> Are cathodic protection readings consistently adequate during annual monitoring? <input type="radio"/> Do exposed pipe inspections indicate external corrosion? <input type="radio"/> Do exposed pipe inspections indicate coating deterioration? 			
	Other metallic materials	<ul style="list-style-type: none"> <input type="radio"/> Do other metallic materials exist in the system? <input type="radio"/> Is the pipe cathodically protected? <input type="radio"/> Have corrosion leaks occurred? 			
	Internal corrosion	<ul style="list-style-type: none"> <input type="radio"/> Does metallic pipe exist in the system? <input type="radio"/> Do piping inspections indicate internal corrosion? <input type="radio"/> Have internal corrosion leaks occurred? <input type="radio"/> Have liquids been found in your system? 			

Table 4.1 Continued

Primary Threat	Threat Subcategories	Questions to Check Subcategory Applicability to System	Extent of Threat		
			General	Local	NA
CORROSION (Continued)	Atmospheric corrosion	<input type="radio"/> Have corrosion leaks occurred? <input type="radio"/> Do visual inspections indicate external corrosion pitting? <input type="radio"/> Do visual inspections indicate coating deterioration?			
NATURAL FORCES (e.g., earth movement, lightning, heavy rains/floods, temperature extremes, high winds)	Outside force/weather: steel pipe	<input type="radio"/> Do portions of the system lie in areas of known land subsidence, landslides, earthquake fault zones, or washouts?			
	Outside force/weather: plastic pipe	<input type="radio"/> Has outside force caused plastic pipe to fail? <input type="radio"/> Do portions of the system lie in areas of known land subsidence, landslides, earthquake fault zones, or washouts?			
	Outside force/weather: cast iron pipe	<input type="radio"/> Are there leaks due to ground movement, frost heave, or earth subsidence?			
EXCAVATION DAMAGE	Operator (or its contractor)	<input type="radio"/> Are damages being caused by crews not following one-call laws? <input type="radio"/> Are damages increasing? <input type="radio"/> Have damages from mislocated lines or poorly performing locators been experienced? <input type="radio"/> Are facilities marked out, and marked out accurately? <input type="radio"/> Are damages being caused by failure to protect pipe during backfill operations? <ul style="list-style-type: none"> • Were facilities installed using trenchless technologies, such that a cross bore condition may exist? 			
	Third-party	<input type="radio"/> Has an increase in construction activity been experienced? <input type="radio"/> Is there a one-call system covering the distribution system? <ul style="list-style-type: none"> • Is there a one-call system function covering the clearing of sewer pipes? <input type="radio"/> Are damages being caused from mislocated lines or poorly performing locators? <input type="radio"/> Are damages being caused by failure to protect pipe during backfill operations?			

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)	<input type="radio"/> Have leaks been experienced on the system where previous damage has occurred <input type="radio"/> Are there known areas of blasting or demolition activity? <input type="radio"/> Have leaks occurred due to blasting? <input type="radio"/> 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	<input type="radio"/> Are aboveground facilities being hit by vehicles? <input type="radio"/> Are aboveground facilities located near a roadway, driveway, or other location where they may be susceptible to vehicular damage? <input type="radio"/> Are susceptible aboveground facilities protected from vehicular damage?			
	Vandalism	<input type="radio"/> Has damage or leakage been caused by malicious actions of unauthorized individuals? <input type="radio"/> Has gas theft occurred?			
	Fire/Explosion (primary)	<input type="radio"/> 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)	<input type="radio"/> Have significant numbers of previous damage cases been found? <input type="radio"/> Has leakage caused by previous damage occurred?			
	Blasting	<input type="radio"/> Does the potential for blasting operations near gas facilities exist? <input type="radio"/> Are appropriate procedures in place? <input type="radio"/> Has blasting damage occurred?			
	Mechanical damage: > Steel pipe > Plastic pipe > Pipe components	<input type="radio"/> Have failures due to mechanical damage been experienced, such as underground structures in contact with facilities?			
MATERIAL OR WELD	Manufacturing defects	<input type="radio"/> 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	<input type="radio"/> 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	<input type="radio"/> Have failures in welds or other joints occurred?			
EQUIPMENT FAILURE	System equipment	<input type="radio"/> Have failures been experienced due to leaking seals or gaskets? <input type="radio"/> Have regulator or control malfunctions been experienced? <input type="radio"/> Have valve leaks/failures occurred? <input type="radio"/> Have other gas carrying facilities malfunctioned?			
INCORRECT OPERATION	Inadequate procedures	<input type="radio"/> Have failures been experienced due to inadequate procedures?			
	Inadequate safety practices	<input type="radio"/> Have failures been experienced due to inadequate safety practices?			
	Failure to follow procedures	<input type="radio"/> Have failures been experienced due to a failure to follow procedures?			
	Construction/workmanship defects	<input type="radio"/> Have failures been experienced due to workmanship defects?			
OTHER		<input type="radio"/> Have failures been experienced due to other reasons?			

TABLE 4.1 - SAMPLE THREAT IDENTIFICATION METHOD

4.4 Handling Interactive Threats.

Piping systems may be coincidentally 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*.

Example 1: 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.

Example 2: 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 risk³ 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.

- (b) Information evaluation approaches may range from the simple stand-alone approach to a more sophisticated approach.
 - (1) Stand-alone approaches may include any one of the following.
 - (i) Having a knowledgeable person (subject matter expert (SME))⁴ review available information.
 - (ii) Conducting periodic inter-departmental meetings.
 - (iii) Conducting periodic SME meetings.
 - (iv) Assigning a centralized department to review all information.
 - (v) Using an electronic database or work management system.
 - (vi) Using risk evaluation software that compiles relevant information.
 - (2) Sophisticated approaches may include an operator choosing to use several stand-alone approaches in combination as a process for information evaluation.

5.3 *Methods.*

Two general approaches to risk evaluation are as follows.

- (a) The use of knowledgeable persons (the SME method).
- (b) The use of mathematical (algorithm) methods.

If an operator uses a combination of methods for different parts of a system, the results of these methods should be combined for common risk ranking.

(a) Subject Matter Expert (SME) Method.

- (1) The purpose of using an individual SME or forming a SME group is to review the information gathered during routine operations and maintenance activities, as well as any special field surveys or patrols to determine where the problems occurred and if the problems will likely recur. In addition, SMEs may be sources of information about a distribution system. When combined with perceived or known consequences, a relative risk ranking can be assigned to each facility or group of facilities experiencing problems.
- (2) An individual SME or a SME group can perform an elaborate evaluation or a more simplified evaluation based on the particular nature of a system and its operation.

(b) Mathematical Method.

- (1) An operator may use existing commercially available (off-the-shelf) or internally developed software that performs risk evaluation. The operator should consider what information is required to use the selected software, what information is readily available, and the general applicability of the mathematical model to the operator's system. There are also "predictive" models that can be used for risk evaluation.
- (2) Operators should consider using a Failure Mode and Effects Analysis (FMEA) model or an equivalent structured and systematic method to identify and mitigate risks. FMEA is an accepted and recognized engineering practice used to identify and assess potential failures, including common mode failures. This risk mitigation method may not be suitable for all gas systems. For additional information, see OPS Advisory Bulletin ADB-2020-02 (85 FR 61097, September 29, 2020; reference Guide Material Appendix G- 192-1, Section 2).

5.4 *Example of risk evaluation.*

The following paragraphs describe one example of a SME-type of risk evaluation. The operator has the option to use any method that determines the relative importance of each threat and produces a relative risk ranking.

(a) Group the facilities.

- (1) The goal of this step is to group together facilities (pipe or components) with common traits that experience similar problems. The risk ranking result, if any, can then be applied to the group of facilities as appropriate. Facility grouping may be modified at any time when additional information becomes available. Groups that experience problems will be included in the risk-ranking step.

⁴ *SMEs are persons knowledgeable about design, construction, operations, maintenance activities, or characteristics of a pipeline system. Designation as an SME does not necessarily require specialized education or advanced qualifications. Some SMEs may possess such expertise, but detailed knowledge of the pipeline system gained by working with it over time can also make someone an SME. SMEs may be employees, consultants, contractors, or any suitable combination of these.*

- (2) The operator should determine where in the system problems occur. Consider each component or facility that is experiencing a problem separately or group them together if they share common traits. Review available records, interview knowledgeable personnel, or perform both. Common trait examples might include one or more of the following.
 - (i) Pipe material.
 - (ii) Pipe specifications.
 - (iii) Pipe type (main or service line).
 - (iv) Cathodic protection history.
 - (v) Specific brand and model of fitting.
 - (vi) Age.
 - (vii) Geographical and/or geological area.
 - (viii) Operation and maintenance history.
 - (ix) Known installation practices.
 - (x) Mandatory or voluntary one-call system.
 - (xi) Amount of construction activity.
 - (xii) Typical excavation method (e.g., blasting, plowing, planting, open trench, trenchless).
 - (3) Based on the judgment of the operator, any facility grouping may be identified for risk ranking because of other significant factors.
 - (4) The operator should evaluate problem trends. Stable or improving trends may require no further action. The following are examples that could be used by an operator to determine if a particular trend exists. More examples can be found in Section 7.2 below.
 - (i) Outside Force - Excavation:
 - (A) Leaks on mains per miles of main.
 - (B) Leaks on services per number of services.
 - (ii) Outside Force – Other:
 - (A) Leaks on mains per miles of main.
 - (B) Leaks on services per number of services.
 - (iii) Other Than Outside Force:
 - (A) Leaks on mains per miles of main.
 - (B) Leaks on services per number of services.
- (b) Risk ranking
- (1) One simple approach to risk ranking is to create a risk matrix (see Table 5.3) and assign values to each facility or group of facilities based on the known operating history and the input from the operator's SMEs. The matrix considers two factors: frequency and consequence. *Frequency* refers to the number of problems the operator has experienced with the facility or group of facilities being ranked and is used here as an indication of the likelihood of problems occurring in the future. *Consequence* refers to the extent of potential damage if the problem is not mitigated. The operator will need to assign a value to each factor.
 - (2) A sample of how to set up a table of frequency factors and example considerations for assigning such factors to the threat of excavation damage is shown in Table 5.1.

Example Frequency Factors	Example Considerations
LOW	Few problems (or frequency of excavation damage) experienced, excavators generally responsive, good mapping/locating records, mitigation implemented and effective.
MEDIUM	Moderate number of problems (or frequency of excavation damage) experienced, excavators not generally responsive, moderate mapping/locating records, mitigation implemented but effectiveness not yet demonstrated.
HIGH	High number of problems (or frequency of excavation damage) experienced, excavators non-responsive, poor or no mapping / locating records.

TABLE 5.1 - SAMPLE FREQUENCY FACTORS FOR EXCAVATION DAMAGE

- (3) A sample of how to set up a table of consequence factors and example considerations for assigning such factors is shown in Table 5.2.

Example Consequence Factors	Example Considerations
LOW	Rural location, small-diameter pipe, low operating pressure.
MEDIUM	Residential location, medium-diameter pipe, medium operating pressure.
HIGH	Predominantly multi-story buildings, large-diameter pipe, high operating pressure.

TABLE 5.2 - SAMPLE CONSEQUENCE FACTORS FOR EXCAVATION DAMAGE

- (4) The operator may choose to assign a numerical value to each factor (e.g., 1 for Low, 3 for High) and multiply the frequency and consequence factors together to gain a numerical result. Alternatively, the operator may choose to use the relative risk-ranking as a non-numerical result (e.g., High-High has a higher relative risk than Low-High). Table 5.3 demonstrates one method of organizing this process. For example, a facility group with a consequence factor of Low (1), and a frequency factor of Medium (2) would have an overall relative risk-ranking score of 2 (1 x 2). The operator may choose to use fewer or more factors than illustrated.

Consequence Factor (Multiplier ¹)	Frequency Factor (Multiplier ¹)		
	LOW (1)	MEDIUM (2)	HIGH (3)
LOW (1)	1 x 1	1 x 2	1 x 3
MEDIUM (2)	2 x 1	2 x 2	2 x 3
HIGH (3)	3 x 1	3 x 2	3 x 3

¹ Determined by operator

TABLE 5.3 - SAMPLE RELATIVE RISK CALCULATION

- (5) This risk matrix method is one option for risk-ranking and, in this example, requires the operator to determine overall scores in the Frequency and Consequence categories for each facility or group of facilities. Since the considerations for developing these factors overlap and can vary (e.g., it may be a small-diameter pipe in a residential area), the operator should determine how the overall score will be established.
- (6) A high score is not an absolute measure of risk. Scores can be used to determine a relative risk between two or more facilities or groups of facilities to help the operator prioritize risk management actions.
- (7) The matrix method may be enhanced by adding more detail based on other considerations (see Tables 5.1 and 5.2), or by assigning a numerical value to each consideration and summing up all considerations for each factor. For example, a small-diameter pipeline, operating at medium pressure, and located in a Class 4 area (high-rise buildings). The operator, using consequence factor multipliers similar to those shown in Table 5.2, could sum up a total consequence factor of 6 (small diameter (Low = 1) + medium pressure (Medium = 2) + predominantly high-rise buildings (High = 3)). Another approach is to use the highest of any considerations used (in this case: high-rise buildings = High = 3). Either approach results in a relative risk ranking. The same logic can be used for frequency factors.

5.5 Validation.

- (a) The operator should validate the results of the risk ranking by asking one or both of the following questions.
 - (1) Do the results and the operations and maintenance records focus on the same facilities or groups of facilities?
 - (2) Do the results agree with the experiences of the operator's SME(s)?
- (b) If the answer to either of the above questions is "no," the operator should consider reviewing and revising the risk evaluation process, gathering additional data, or reevaluating the level of SME knowledge. A "no" answer does not necessarily mean that the risk ranking is wrong or that either the SME knowledge or operations and maintenance records are incorrect. What it does indicate is that there is a difference that needs to be understood. It could be that the risk matrix used failed to incorporate some important factors, or it may be that there are factors important to risk that SMEs and operations personnel did not recognize because they have never faced them. It is important that the operator understands the reasons for the difference, makes any adjustments to its risk evaluation that are found necessary, and has confidence that the final results accurately represent its system.

6 IDENTIFY AND IMPLEMENT MEASURES TO ADDRESS RISKS

Risk management measures are techniques or practices consisting of a broad category of activities that includes prevention, remediation, mitigation, and additional or accelerated (A/A)⁵ actions. This section provides guide material on A/A actions.

This section offers techniques and actions that have the potential to reduce the risks to a distribution system. There may be other ways to accomplish the same goal. This guidance is not intended to rule out any valid approach an operator uses that leads to safety improvements in the operation of its distribution system. Remember that risk can be managed by eliminating or reducing the likelihood or by lessening the consequences of a potential problem. Section 192.1007(d) requires that these measures include an effective leak management program, unless all leaks are repaired when found.

6.1 General.

- (a) Gas distribution systems are made up of various materials and components located in different geographic locations and operated under varying conditions. Accordingly, a risk management technique or practice used by one operator may not have application as a risk management technique or practice to another operator. An operator may have different risk management techniques or practices for different facilities or group of facilities within the same operating environment. If risk management techniques or practices are necessary, the operator may choose those that are appropriate to protect the public for the system being operated.
- (b) Risk management techniques and practices vary in that they may address either the likelihood of a problem or the consequence of a problem.
- (c) Risk management techniques and practices may address one or more of the identified threats. Operators should rank risks to their system and determine which risk management techniques and practices are most appropriate.
- (d) There are a number of ways an operator can address threats and reduce risk to a distribution system. Examples of A/A actions that may be applied as risk management techniques and practices are listed in Table 6.1. An operator may consider these or develop other techniques or practices specific to its system to address the identified risks.

6.2 Leak Management Program.

- (a) Leak management is an important risk management technique used by natural gas distribution operators to maintain the integrity of their distribution systems. Operators consider many factors specific to their geographical location and their specific distribution system to evaluate the severity of the leaks and determine the appropriate actions to mitigate the risk associated with the leaks. The operator may also utilize industry-recognized guidelines or develop and implement an operator-specific, or state-specific, leak management program.
- (b) Although some elements of leak management have evolved with improvements in technology and the development of operation and maintenance codes and standards, distribution operators have used the same basic elements since the early days of the industry.
- (c) An effective leak management program has the following basic elements.

Locate the leaks in the distribution system;
Evaluate the actual or potential hazards associated with these leaks;
Act appropriately to mitigate these hazards;
Keeep records; and
Self-assess to determine if additional actions are necessary to keep people and property safe.

⁵ A/A actions are activities that are performed in addition to the requirements of the Federal Regulations.

(1) Locate the leaks.

An effective leak management program starts with detecting and locating leaks. This may be accomplished with the proper use of leak detection equipment and techniques when conducting leak surveys, when investigating notifications of gas odors, and in a variety of other activities. It involves the use of qualified personnel to perform leak detection activities with appropriately selected leak detection equipment and techniques. Operators should have internal procedures that define the frequency and type of leak surveys to be conducted. These may be based on the type of gas transported, environmental conditions, the operator's knowledge of the distribution system, and regulatory requirements.

- (2) Evaluate the severity of the leaks.
 - (i) The next step is evaluating the hazards associated with the leaks found according to established classification criteria, either generally recognized by the industry or operator-specific. These classification criteria take into consideration the safety risk posed by each leak.
 - (ii) Leaks could be classified using the following GPTC Guide criteria.
 - (A) Leaks that require immediate action (hazardous leaks). A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.
 - (B) Leaks scheduled for repair. A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable hazard.
 - (C) Monitored leaks. A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.
 - (iii) Operators who have established separate classifications with their state regulators should follow those classifications.
- (3) Act appropriately to mitigate the hazards associated with each leak.

Once a leak has been located and classified, an operator takes actions that are consistent with the classification of that leak. This may include temporary or permanent repair, replacement, or other steps that reduce any immediate hazard posed by the leak. This may also include scheduling the line for repair or periodic monitoring in the case of non-hazardous leaks.
- (4) Keep records.

This activity includes the collection and recording of data to evaluate the effectiveness of the leak management program and to allow for trend analysis. The records should provide sufficient data to allow all regulatory required reports to be filed, and to allow an effective self-assessment to be made.
- (5) Self-assess.

It is advisable for an operator to conduct a periodic self-assessment of its leak management program using performance metrics appropriate to its particular distribution system. The purpose of a periodic self-assessment is to determine if the leak management program is effective and, if necessary, to identify changes necessary to assure that it is effective.

6.3 A/A actions.

Table 6.1 provides examples of some A/A actions applicable to managing the risk posed by each threat. An operator may implement one or more of the A/A actions in the table when addressing one or more of the risks. The examples given are not intended to rule out any other reasonable action that an operator may select to reduce the risk to its system. When necessary, operators are encouraged to develop A/A actions that they believe to be more appropriate to their particular distribution systems.

Threats		Examples of Possible A/A Actions
Primary	Subcategory	
CORROSION	External corrosion: Bare steel pipe (CP or no CP)	<ul style="list-style-type: none"> ○ Increase frequency of leak surveys. ○ Replace, insert, or rehabilitate. ○ Provide hot spot protection (e.g., install anodes at anodic locations). ○ Correct cathodic protection deficiencies. ○ For stray current, depending on type (e.g., interference, DC powered rail transit system, AC) consider: <ul style="list-style-type: none"> > Installing bond(s). > Installing or improving isolation (e.g., remove contact/short). > Work with transit system operator to reduce effect.
	External corrosion: cast iron pipe (graphitization)	<ul style="list-style-type: none"> ○ Increase frequency of leak surveys. ○ Replace or insert. ○ For stray current, depending on type (e.g., interference, DC powered rail transit system, AC) consider: <ul style="list-style-type: none"> > Installing bond(s). > Installing or improving isolation (e.g., remove contact/short). > Work with transit system operator to reduce effect.
	External corrosion: coated and wrapped steel pipe (CP or no CP)	<ul style="list-style-type: none"> ○ Increase frequency of leak surveys. ○ Replace, insert, or rehabilitate. ○ Replace deteriorated coating. ○ Increase CP level. ○ Replace anodes with rectifiers. ○ Add anodes or rectifiers. ○ For stray current, depending on type (e.g., interference, DC powered rail transit system, AC) consider: <ul style="list-style-type: none"> > Installing bond(s). > Installing or improving isolation (e.g., remove contact/short). > Work with transit system operator to reduce effect.
	Other metallic materials	<ul style="list-style-type: none"> ○ Increase frequency of leak surveys. ○ Replace with steel or PE. ○ Modify CP systems or protection levels.
	Internal corrosion	<ul style="list-style-type: none"> ○ Increase frequency of leak surveys. ○ Install drips. ○ Install pipe liner. ○ Install moisture removal or control equipment. ○ Evaluate gas supply inputs and take corrective action with supplier.
	Atmospheric corrosion	<ul style="list-style-type: none"> ○ Coat (paint) the exposed piping. ○ Increase survey frequency. ○ Replace or rehabilitate. ○ Relocate.

Table 6.1 Continued

Threats		Examples of Possible A/A Actions
Primary	Subcategory	
NATURAL FORCES (e.g., earth movement, lightning, heavy rains/floods, temperature extremes, high winds)	Outside force/weather:	<ul style="list-style-type: none"> ○ Relocate pipe from high risk locations. ○ Replace pipe in high risk locations. ○ Install slip or expansion joints for earth movement. ○ Install strain gages on pipe. ○ Install automatic shut-offs. ○ Expand the use of excess flow valves. ○ Conduct leak survey after significant earthquake or other event.
	Outside force/weather: Plastic pipe	<ul style="list-style-type: none"> ○ Relocate pipe from high risk locations. ○ Replace pipe in high risk locations. ○ Expand the use of excess flow valves. ○ Conduct leak survey after significant earthquake or other event.
	Outside force/weather: Cast iron pipe	<ul style="list-style-type: none"> ○ Replace. ○ Leak survey after an event. ○ Install additional facilities to increase flexibility (e.g., expansion bends, expansion joints).
EXCAVATION DAMAGE	Operator (or its contractor)	<ul style="list-style-type: none"> ○ Conduct enhanced awareness education. ○ Conduct cross bore awareness education. ○ Inspect targeted excavation and backfill activities. <ul style="list-style-type: none"> > Ensure separation, as needed, from existing facilities and those being installed. > Inspect substructure facilities in vicinity of past and present trenchless excavation activities to determine the presence of cross bores. ○ Inspect for facility support. <ul style="list-style-type: none"> > Ensure inserted facilities are adequately supported. ○ Improve accuracy of line locating. <ul style="list-style-type: none"> > Install tracer wire. > Enhance the locating signal by connecting a small anode to the tracer wire. > Install electronic marking devices. ○ Expand the use of excess flow valves. ○ Improve system map accuracy (e.g., updates from field observation or GPS data). ○ Improve system map availability. ○ Install additional line markers.

Table 6.1 Continued

Threats		Examples of Possible A/A Actions
Primary	Subcategory	
EXCAVATION DAMAGE (Continued)	Third Party	<ul style="list-style-type: none"> ○ Conduct enhanced awareness education. ○ Request regulatory intervention. ○ Inspect targeted excavation and backfill activities. <ul style="list-style-type: none"> > Ensure separation, as needed, from existing facilities and those being installed. ○ Inspect for facility support. <ul style="list-style-type: none"> > Ensure inserted facilities are adequately supported. ○ Improve accuracy of line locating. <ul style="list-style-type: none"> > Install tracer wire. > Enhance the locating signal by connecting a small anode to the tracer wire. > Install electronic marking devices. ○ Participate in pre-construction meetings with project engineers and contractors in high-risk areas. ○ Use warning tape. ○ Expand the use of excess flow valves. ○ Improve system map accuracy (e.g., updates from field observation or GPS data). ○ Improve system map availability. ○ Recruit support of public safety officials (e.g., fire department). ○ Install additional line markers. ○ Seek additional enforcement authority or other changes to one-call system.
OTHER OUTSIDE FORCE DAMAGE	Vehicular	<ul style="list-style-type: none"> ○ Expand policy on when and how to install protection. ○ Increase frequency of patrols/inspections of high-risk facilities. ○ Evaluate the need to relocate hard-to-protect facilities. ○ Expand the use of excess flow valves.
	Vandalism	<ul style="list-style-type: none"> ○ Install or improve fences/enclosures. ○ Increased surveillance. ○ Relocate hard-to-protect or critical facilities.
	Fire/explosion (primary)	<ul style="list-style-type: none"> ○ Provide local first responder training. ○ Install curb valves. ○ Improve response capability. ○ Expand the use of excess flow valves.
	Leakage (previous damage)	<ul style="list-style-type: none"> ○ Inspect exposed pipe prior to backfill. ○ Increase frequency of leak surveys.
	Blasting	<ul style="list-style-type: none"> ○ Perform leak survey after blasting. ○ Relocate away from frequent blast areas (e.g., mines). ○ Replace with more ductile pipe material.

Table 6.1 Continued

Threats		Examples of Possible A/A Actions
Primary	Subcategory	
OTHER OUTSIDE FORCE DAMAGE (Continued)	Mechanical damage > Steel pipe > Plastic pipe > Cast iron > Pipe components	<input type="checkbox"/> Increase frequency of leak surveys. <input type="checkbox"/> Replace or repair. <input type="checkbox"/> Revise construction procedures. <input type="checkbox"/> Revise material standards. <input type="checkbox"/> Trend material failures.
MATERIAL OR WELD	Manufacturing defects	<input type="checkbox"/> Increase frequency of leak surveys. <input type="checkbox"/> Replace or repair. <input type="checkbox"/> Revise construction procedures. <input type="checkbox"/> Revise material standards. <input type="checkbox"/> Trend material failures. <input type="checkbox"/> Trend weld or other joint failures.
	Materials/Plastic	<input type="checkbox"/> Increase frequency of leak surveys. <input type="checkbox"/> Replace. <input type="checkbox"/> Add warning markers/tape. <input type="checkbox"/> Highlight locations on maps. <input type="checkbox"/> Employ special procedures to provide continuous on-site monitoring of excavation activity near the gas facility, and provide protection as necessary.
	Weld/Joint	<input type="checkbox"/> Increase frequency of leak surveys. <input type="checkbox"/> Replace or repair. <input type="checkbox"/> Revise construction procedures. <input type="checkbox"/> Revise material standards. <input type="checkbox"/> Trend material failures. <input type="checkbox"/> Trend weld or other joint failures. <input type="checkbox"/> Increase frequency of training on welding and joining procedures. <input type="checkbox"/> Inspect field joints using personnel other than the welder, welding operator, or joiner.
	Malfunction of welding or joining equipment	<input type="checkbox"/> Increase frequency of maintenance inspections on welding and fusion equipment.
EQUIPMENT FAILURE	System equipment	<input type="checkbox"/> Replace or repair. <input type="checkbox"/> Increase frequency of inspection/monitoring. <input type="checkbox"/> Investigate if a type of joint or equipment is being used in inappropriate situations/locations. <input type="checkbox"/> Improve installation procedure. <input type="checkbox"/> Trend equipment failure.

Table 6.1 Continued

Threats		Examples of Possible A/A Actions
Primary	Subcategory	
INCORRECT OPERATION	Inadequate procedures	<input type="radio"/> Improve procedures. <input type="radio"/> Improve training. <input type="radio"/> Evaluate locations where inadequate practices may have been used. <input type="radio"/> Perform internal audits or inspections.
	Inadequate safety practices	<input type="radio"/> Improve safety procedures and practices.
	Failure to follow procedures	<input type="radio"/> Improve supervision. <input type="radio"/> Improve training. <input type="radio"/> Improve evaluations.
	Construction/ Workmanship defects	<input type="radio"/> Increase frequency of leak surveys. <input type="radio"/> Replace or repair. <input type="radio"/> Revise construction procedures. <input type="radio"/> Revise material standards. <input type="radio"/> Trend material failures. <input type="radio"/> Trend weld or other joint failures. <input type="radio"/> Inspect field joints using personnel other than the welder, welding operator, or joiner.
OTHER		<input type="radio"/> Increase frequency of leak survey. <input type="radio"/> Increase odorant level. <input type="radio"/> Increase frequency of odorant testing. <input type="radio"/> Improve choices of odorant testing locations.

TABLE 6.1 - EXAMPLES OF ADDITIONAL OR ACCELERATED (A/A) ACTIONS

7 MEASURE PERFORMANCE, MONITOR RESULTS, AND EVALUATE EFFECTIVENESS

Measuring performance is a means to determine if a risk management technique or practice (A/A action) is effective. Each operator should develop performance measures that match the risk management technique or practice it has applied to its DIMP. Measures developed or selected may be unique to each operator. Measures may be gathered and tracked for an entire system, specific geographic areas, material type, each facility or group of facilities, or other reasonable categorization. Section 7.2 provides examples of internal performance measures from which an operator may select to measure the effectiveness of its DIMP. Section 192.1007(e) requires that performance measures include the following.

- (a) Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by cause;
- (b) Number of excavation damages;
- (c) Number of excavation tickets (receipt of information by the underground facility operator from the notification center);
- (d) Total number of leaks either eliminated or repaired, categorized by cause;
- (e) Number of hazardous leaks either eliminated or repaired (or total number of leaks if all leaks are repaired when found), categorized by material; and
- (f) Any additional measures to evaluate the effectiveness of the operator’s DIMP in controlling each identified threat.

7.1 Guidelines for developing performance measures.

When developing or selecting performance measures, consider the following.

- (a) Performance measures should address the specific risk management practices of the operator's DIMP.
- (b) Performance measures should be something that can be counted, tracked, monitored, and supported.
- (c) It is best to select a few critical measurements, since too many can decrease the measurement system effectiveness.
- (d) Whenever possible, performance measures should be developed or selected that can utilize data the operator already collects and has accumulated. This will allow establishment of historical benchmarks or baselines against which the effect of risk management practices can be measured. It is not intended that the operator launch a major new program of data collection to develop performance measures. New information collection should be necessary only if no meaningful performance measure can be derived or selected using existing data sources.
- (e) Use of numeric performance measures, where practical, is recommended. Numerical measures are more likely to be objective, supportable, and reproducible. Numerical data also allows direct comparisons between materials, locations, procedures, etc. In this context, "numeric" may mean a raw number, a percentage, per mile or per service, or any other mathematical expression that makes the data meaningful.
- (f) However, non-numeric methods should not be ignored. For example, anecdotal statements from field personnel can contribute as follows.
 - (1) Provide an important source of information on the merit and effectiveness of a risk management technique or practice.
 - (2) Help determine whether the practice has been properly implemented.
 - (3) Be useful to validate or challenge what numerical data is indicating.

7.2 Examples of performance measures.

Below is a list of examples that may be useful for determining the effectiveness of actions taken under a DIMP. This list is not intended to be all-inclusive. There may be others that are a better fit to individual circumstances. This guidance is not intended to rule out any other reasonable measure that an operator may select. It is not intended that operators should be expected to use each listed measure. The purpose of the list is only to provide examples to aid in the selection of risk management technique or practice performance measures.

The examples listed are broadly applicable performance measures organized under the eight primary threat categories. An operator may select "a critical few" measurements from the following list. A more detailed breakdown of the selected few may be necessary for effective results. For example, material failures may need to be categorized by specific pipe type, age, or manufacturer to focus on the root cause of such failures.

- (a) Corrosion.
 - (1) Leaks due to external or internal corrosion.
 - (2) Exposed pipe condition reports that found corrosion or coating damage.
 - (3) Repairs required due to non-leaking pitting or coating damage (above and below ground).
 - (4) Cathodic protection zones found with low protection levels.
 - (5) Areas of active corrosion found (unprotected pipe).
- (b) Natural forces.
 - (1) Leaks due to weather or other natural forces.
 - (2) Repair, replacement or relocation actions due to natural forces.
- (c) Excavation damage.
 - (1) Excavation damages as defined in §192.1001 (first / second / third party).
 - (2) Normalized damages (damage ratio) defined as damages per 1,000 tickets. A *ticket* is defined as the receipt of information by the underground facility operator from the notification center regarding onsite meetings, project design, or a planned excavation.

- (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.

10 REPORT FITTING FAILURES

Except for master meter or small LPG operators, operators are required to report the total number of hazardous leaks caused by mechanical fitting failures on the distribution annual report Form F7100.1-1.

Note: *Hazardous leak and mechanical fitting* are defined in §192.1001.

11 SAMPLE DIMP APPROACHES

11.1 SME approach.

Because this approach relies more on personnel knowledge and experience, operators of smaller, less complex systems may find it more appropriate.

- (a) Identify distribution system problems that have occurred and relate these to the eight identified primary threat categories. An operator may choose to break down the primary threat categories into subcategories for more effective understanding and focus.
- (b) Use the knowledge and experience of SMEs and other available information to understand the distribution system and its associated operating and maintenance experience.
- (c) Use the identified threats and associated consequences, evaluate and rank the involved risks.
- (d) If additional or accelerated risk management measures are needed, take reasonable actions to address the targeted risks.
- (e) Establish performance measures for key risk management activities and monitor accordingly.
- (f) Periodically evaluate performance measure trends and indications. Change program procedures or activities as needed.
- (g) Report information as required.

11.2 Mathematical approach.

This approach may require more rigorous segmentation or grouping of specific information. Thus it may be more suited for operators with records and mapping information tracked electronically.

- (a) Identify and gather available information about the distribution system and its associated operating and maintenance experience.
- (b) Establish criteria for identifying facilities or groups of facilities within the distribution system. Then, using the knowledge and experience of SMEs together with other available information, decide which factors (e.g., pipeline traits, threats, consequences, environments) are associated with each identified facility or group of facilities. An operator may choose to break down the primary threat categories into subcategories for more effective understanding and focus.
- (c) Assign weighting values to relevant factors involved and using a mathematical tool, analyze and establish a risk score for each facility or group of facilities. Based on calculated scores and supplemental considerations from SMEs, the facilities or groups of facilities can be ranked accordingly.
- (d) For facilities or groups of facilities where further risk reduction is needed, implement activities that the operator believes will best achieve the desired results.
- (e) Identify and track performance measures to determine whether the efforts to manage targeted risks are effective.
- (f) Periodically evaluate performance measure trends and indications and change program procedures or activities as needed.
- (g) Report information as required.

GUIDE MATERIAL APPENDIX G-192-9

(See guide material under §§192.143, 192.503, 192.505, 192.507,
192.509, 192.513, 192.619, 192.921, and Guide Material Appendix G-192-9A)

TEST CONDITIONS FOR PIPELINES OTHER THAN SERVICE LINES

This table is presented as a compilation for the application of the test requirements in §§192.143, 192.503, 192.505, 192.507, 192.509, 192.513, and 192.619 as they apply to pipelines other than service lines. Additional guidance is provided in the notes.

	Other Than Plastic				Plastic
	Under 30 Percent SMYS			30 Percent SMYS and Over	
Maximum Operating Pressure	Less than 1 psig	1 psig but less than 100 psig	100 psig and over	All pressures	All pressures See Note (2)
Test Medium	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas See Note (3)	Water Air Natural gas Inert gas	Water Air Natural gas Inert gas See Note (4)
Maximum Test Pressure	See Note (5)	See Note (5)	See Note (5)	See Note (5)	3 x design pressure See Notes (6) and (7)
Minimum Test Pressure	10 psig	90 psig	Maximum operating pressure multiplied by class location factor in §192.619 (a)(2)(ii); See Note (3)	Maximum operating pressure multiplied by class location factor in §192.619 (a)(2)(ii); See Note (8)	50 psig or 1.5 x maximum operating pressure, whichever is greater See Note (6)
Minimum Test Duration	See Note (9)	See Note (9)	1 Hour and see Note (9)	8 Hours (See Notes 8 & 9)	See Note (9)

Notes:

- (1) Determining whether a new segment of pipeline should be tested per §192.505 (30% SMYS and over) or per §192.507 (under 30% SMYS and at or above 100 psig) is dictated by the percent of SMYS at MAOP. Some pipelines, generally tested per §192.505, may contain segments or have connections that are tested per §192.507. For examples, see the following.
 - (a) If a new lateral is to be installed on a pipeline that operates over 30% SMYS, and the new lateral will operate with an MAOP that is less than 30% SMYS and at or above 100 psig, the new lateral is covered by §192.507, even though the header pipe might have been tested per §192.505.
 - (b) If a segment of transmission line is replaced with different-wall-thickness or stronger pipe that will operate with an MAOP below 30% SMYS, the replacement pipe segment is covered by §192.507, even if the majority of the pipeline has been tested per §192.505. However, in this situation the operator might consider testing in accordance with §192.505 to avoid possible issues with the following.

- (i) Section 192.555(b)(1) and (b)(2), if the pipeline segment is uprated in the future to 30% SMYS or more.
 - (ii) Section 192.611(a)(1), if there is a confirmation or revision of the MAOP in the future due to a change in class location.
- (2) Plastic pipe must be designed in accordance with §192.121.
 - (3) Whenever test pressure is 20% SMYS or greater and air, natural gas, or inert gas is the test medium, the line must be checked for leaks either by a leak test at a pressure greater than 100 psig but less than 20% SMYS or by walking the line while the pressure is held at 20% SMYS (§192.507(b)).
 - (4) See test temperature limitations for thermoplastic material in §192.513(d).
 - (5) Refer to §192.503(c) for limitations when testing with air, natural gas, or inert gas. There are no limitations for water test. For all test media, pipeline components must be taken into consideration when determining the maximum test pressure. When water is used as the test medium, it is essential to consider elevation differences to avoid overpressuring pipe at lower elevations in the segment. The pressure at lower elevations is determined by adding 0.43 psig for every foot of elevation differential to the test pressure, measured at a higher point.
 - (6) See 9.2 of the guide material under §192.321.
 - (7) Apply 2.5 x design pressure for PE or PA pipe using a design factor of 0.40.
 - (8) Refer to §192.505(a) for testing criteria covering pipelines located within 300 feet of buildings; §192.505(b) for compressor, measuring, and regulator stations; and §192.505(d) for fabricated units and short sections of pipe
 - (9) Duration determined by volumetric content of test section, test medium, test pressure, thermal effects, leak criteria, and instrumentation in order to ensure discovery of all potentially hazardous leaks. See 2 of the guide material under §192.509 and 5 of the guide material under §192.513.

GUIDE MATERIAL APPENDIX G-192-9A

(See guide material under §§192.503, 192.505, 192.506, 192.507, 192.513, 192.517, 192.619, 192.921, and Guide Material Appendix G-192-9)

PRESSURE TESTING GUIDELINES FOR TRANSMISSION INTEGRITY ASSESSMENTS

1 GENERAL

- (a) Pressure testing new and existing steel and plastic (e.g., polyethylene) transmission pipelines is an assessment method that may be used by operators to confirm the integrity of pipelines from time-dependent threats (e.g., internal corrosion, external corrosion, stress corrosion cracking) and time-independent threats (e.g., manufacturing defects, excavation damage, construction damage).
- (b) Pressure testing identifies, through failure, major defects that might threaten a pipeline's integrity or shows that no major flaws were revealed at the time of testing.
- (c) Retesting should be considered for existing steel and plastic transmission pipelines when the following conditions exist.
 - (1) For steel pipelines, direct assessment is not an appropriate assessment method.
 - (2) In-line inspection tools are not appropriate or available.
 - (3) The pipe segment cannot accommodate the passage of in-line inspection tools due to restrictions in components, such as elbows or valves.
 - (4) Operator can maintain service to affected customers by having bi-directional system flow, an alternative supply source, or flexibility to take the pipe segment out of service.
 - (5) The gas flow or other pipeline conditions are not sufficient for running in-line inspection tools.
- (d) See Guide Material Appendix G-192-9 for guidelines in selecting an appropriate pressure testing medium for steel and plastic transmission pipe segments.
- (e) Consideration should be given to the qualifications required for personnel involved in pressure testing.

2 PRESSURE TESTING ADVANTAGES AND DISADVANTAGES

See guide material under §192.921 for the advantages and disadvantages of pressure testing new and existing steel and plastic pipelines.

3 PRESSURE TESTING OF STEEL TRANSMISSION PIPELINES

To optimize pressure testing as an integrity assessment tool, pressure testing of new and existing steel transmission pipelines should be conducted in accordance with Subpart J. Operators should consider testing at a higher pressure to detect the greatest number of flaws in the pipe segment.

3.1 *Pressure testing new steel transmission pipelines.*

- (a) The test pressure may be above 100% SMYS at the lowest elevation to provide an adequate test pressure at the highest elevation to ensure fitness for service.
- (b) When any portion is tested above 100% SMYS, a pressure-volume plot should be used to identify

yielding. The test should be stopped if yielding occurs. For additional information on testing to yield, see ASME B31.8, Appendix N (see listing in §192.7, not IBR for Subpart J).

- (c) A pressure test of a new steel transmission pipeline is one of the factors used to establish the MAOP of the test section as a result of the pressure achieved for the proper duration of time (see §192.619(a)(2)).

3.2 *Pressure testing existing steel transmission pipelines.*

When considering pressure testing an existing transmission pipeline, the method of determining MAOP should be reviewed. For pipelines with an MAOP established by grandfathering or maximum safe pressure (§192.619(a)(3) or (4), and §192.619(c)), existing data, such as materials, and the operating and maintenance history should be examined to determine if testing is a suitable assessment method. An operator may review information, if available, from prior pressure testing of the existing pipeline segment. If pressure testing is performed to the highest level attainable for an existing steel transmission pipeline based on its design (i.e., grade, wall thickness, seam type, component ratings, and other factors), then the integrity of the pipeline will be subject to the following conditions.

- (a) Few longitudinally oriented flaws will remain in the test section provided that a sufficiently high ratio of test pressure to MAOP is achieved.
- (b) Pipe integrity is validated if the differential increases between the size of the surviving flaws and the flaw size required to produce a future pipe failure.
- (c) Pressure testing reflects the condition of the test section at a specific point in time. Minor defects, if present, will remain in an undetected state and may continue to grow over time.
- (d) Failure resulting from "pressure reversal" is a potential hazard that can occur after testing has been completed. Pressure reversal occurs when a sub-critical defect survives a higher test pressure, but then fails at a lower pressure in a subsequent repressurization due to continued growth of the defect over time.
- (e) Testing does not provide a measure of corrosion-caused metal loss, or information about the presence, extent, and severity of dents and gouges from excavation or construction damages. In addition, the test pressure at the time may not be high enough to cause failure of these defects.
- (f) The threat of internal corrosion exists for a pipe segment that is not properly dewatered and dried after being hydrostatically tested.

3.3 *General pressure testing considerations for steel transmission pipelines.*

- (a) Pressure tests used for integrity assessments on new or existing steel pipelines must be performed in accordance with the requirements of Subpart J and §192.921.
- (b) The following factors may be considered when selecting a test pressure for an existing pipeline.
 - (1) Mill test certificates to ascertain the pressure test levels in the manufacturing process and pipe data pertaining to specified minimum yield strength along with seam and joint data. If not available, check the listed pipe specification (e.g., API Spec 5L - see §192.7 for IBR for §192.55 and Appendix B to Part 192) applicable to the pipe's manufacturing date to obtain industry specifications for mill testing and pipe data.
 - (2) Previous pressure test results from time of construction or MAOP upgrades.
 - (3) Prior integrity assessments and operating history.

- (4) Number of test failures that will be acceptable to the operator when testing. The probability of pressure reversal failure occurring after completing the test increases with the number of failures permitted during testing. In determining the level of acceptable failures, operators may consider the following factors.
- (i) Likelihood and consequence of a failure.
 - (A) Pipe location.
 - (B) Age and condition of pipe.
 - (C) Pipe welds.
 - (D) Maintenance history of pipe.
 - (ii) Safety of testing personnel.
- (5) Identification of potential safety issues during testing, such as the presence of existing mechanical couplings.
- (6) Integrity assessment intervals based on test pressure attained (see Table 3.3 below which is excerpted from ASME B31.8S-2004, Table 3 - see §192.7 for IBR). If the maximum permitted time interval for a pressure test exceeds 7 years, a confirmatory direct assessment or other assessment must be conducted at intervals not exceeding 7 years (see §192.939).

INTEGRITY ASSESSMENT INTERVALS			
(Reference ASME B31.8S-2004, Table 3 - see §192.7 for IBR)			
Interval Years	<30 Percent SMYS	30 Percent to 50 Percent SMYS	>50 Percent SMYS
5	1.7 x MAOP	1.4 x MAOP	1.25 x MAOP
10	2.2 x MAOP	1.7 x MAOP	1.39 x MAOP
15	2.8 x MAOP	2.0 x MAOP	N/A
20	3.3 x MAOP	N/A	N/A

TABLE 3.3

- (c) See guide material under §§192.503, 192.505, 192.507, 192.509, and Guide Material Appendix G-192-9.

3.4 Spike hydrostatic test.

- (a) A spike hydrostatic test, when performed in accordance with §192.506, is an appropriate integrity assessment method for addressing 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.
- (b) A spike hydrostatic test must be designed to hold pressure at the lower of the following pressures for a minimum of 15 minutes (§192.506).
 - (1) 1.5 times MAOP.
 - (2) 100% SMYS.
- (c) For example, to determine the minimum spike hydrostatic test pressure for a 24" O.D., 0.312 w.t., X52, EFW, class 1 location segment, the following will apply.

- (1) Design pressure = 1,352 psi.
- (2) MAOP = 973 psi (72% SMYS).
- (3) Minimum hydrostatic test pressure: $1.25 \times 973 \text{ psi} = 1,216 \text{ psi}$ (90% SMYS).
- (4) Hydrostatic spike test pressure is lesser of the following:
 - (i) $1.5 \times 973 \text{ psi} = 1,460 \text{ psi}$ (108% SMYS).
 - (ii) 100% SMYS = 1,352 psi.
- (d) A spike hydrostatic test must be performed for a minimum of 15 minutes and occur during the first 2 hours of a pressure test conducted per §192.505 (§192.506(a)(4)). The spike hydrotest duration can be credited for the time duration for the pressure test. For example, during a pressure test with an 8-hour duration, once the segment has reached and stabilized at or above the designated minimum hydrostatic test pressure, the test time can begin. Within the first 2 hours of the test, the pressure is increased (spiked) to the designated minimum spike hydrostatic test pressure, stabilized, and held for a minimum of 15 minutes. Once the 15-minute period has passed, the test pressure may be reduced to the designated minimum test pressure (or higher) and held for the duration of the 8-hour test. The time required to get up to spike hydrostatic test pressure, hold for 15 minutes, and depressurize to the designated minimum test pressure can be included within the 8-hour test duration.
- (e) For additional guidance on the use of spike testing for pipeline integrity purposes, refer to the Pipeline Research Council International (PRCI) report: "Hydrostatic Test Guidelines for Integrity Management".
- (f) See guide material under §192.517 for guidance on records.

4 PRESSURE TESTING PLASTIC TRANSMISSION PIPELINES

4.1 General.

Pressure testing of a plastic transmission pipeline is performed to determine whether leakage or flaws exist in the test section.

4.2 Pressure testing methods for plastic transmission pipelines.

- (a) Pressure testing plastic pipelines may be performed pneumatically or hydrostatically.
- (b) The pipe manufacturer of a plastic test segment may be consulted to determine if restrictions exist that prohibits pneumatic testing.

4.3 Detectable flaws.

See guide material under §192.917 for guidance on the identification of threats and flaws applicable to plastic transmission pipelines. Flaws attributable to manufacturing defects, excavation damage, and installation errors may be found by pressure testing.

4.4 Pressure testing considerations.

The following factors may be considered prior to pressure testing plastic transmission pipelines.

- (a) Pressure testing of plastic pipe is directly affected by the temperature of the test section and test medium. A temperature reduction factor should be applied to test pressure calculations if pipe or test medium temperature exceeds 73 °F. See ASTM F2164 and F2786 for additional guidance. Other testing issues that an operator may consider are Poisson-effect expansion and contraction, and leakage allowance.
- (b) Section 192.513 allows testing to three times the pressure determined under §192.121, at a temperature not less than the pipe temperature during the test. Most manufacturers recommend a maximum test pressure of 1.5 times the design pressure at the lowest elevation in the test section and a test duration of 8 hours or less. See Guide Material Appendix G-192-9 for guidance on the effect of hydrostatic head during pressure testing.

- (c) The presence of metallic components (e.g., transition fittings) should be considered when hydrostatically testing a plastic transmission pipeline since water left in the pipeline may cause internal corrosion.
- (d) Mechanical fittings, if present, should be evaluated to determine whether they have pull-out restraint capability and whether their pressure ratings are appropriate for the anticipated test pressure.
- (e) See 3.3 above for testing considerations relative to integrity assessment intervals, previous pressure tests, upratings, pipe specifications, and joining methods.
- (f) For additional guidance on pressure testing plastic pipelines, see guide material under §192.513.

5 SAFETY

- (a) See guide material under §192.515 for safety considerations when pressure testing transmission pipe segments.
- (b) Additional safety precautions may be required for test sections with segments that are exposed or located above ground during the test.

6 REFERENCES

- (a) ASTM F2164, "Standard Practice for Field Leak Testing of Polyethylene (PE) Pressure Piping Systems Using Hydrostatic Pressure."
- (b) ASTM F2786, "Standard Practice for Field Leak Testing of Polyethylene (PE) Pressure Piping Systems Using Gaseous Media under Pressure (Pneumatic Leak Testing)."
- (c) PPI Handbook of Polyethylene Pipe, Chapter 2, "Inspections, Tests and Safety Considerations."
- (d) "The Benefits and Limitations of Hydrostatic Testing," John F. Kiefner and Willard A. Maxey, available at www.kiefner.com.
- (e) "Role of Hydrostatic Testing in Pipeline Integrity Assessment," John F. Kiefner, available at www.kiefner.com.

GUIDE MATERIAL APPENDIX G-192-10

(See guide material under §192.511, plus
§§192.143, 192.503, 192.507, 192.509, 192.513, and 192.619)

TEST CONDITIONS FOR SERVICE LINES

1 SUMMARY OF PRESSURE TEST REQUIREMENTS

This table is presented as a compilation for the application of the test requirements of §192.511 and §§192.503, 192.507, 192.513, and 192.619 as applied to service lines. Additional guidance is provided in the notes.

Maximum Operating Pressure	Other Than Plastic				Plastic
	Less than 1 psig	1 psig to 40 psig	Over 40 psig but less than 100 psig	100 psig and over	All Pressures See Note (1)
Test Medium	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas	Water Air Natural Gas Inert Gas See Note (2)
Maximum Test Pressure	See Note (3)	See Note (3)	See Note (3)	See Note (3)	3 x design pressure See Notes (4) & (5)
Minimum Test Pressure	See Note (6)	50 psig	90 psig See Note (7)	1.5 x maximum operating pressure; See Notes (7) & (8)	50 psig or 1.5 x maximum operating pressure, whichever is greater; See Note (4)
Minimum Test Duration	See Note (9)	See Note (9)	See Notes (7) & (9)	See Notes (7) & (9)	See Notes (9) & (10)

Notes:

- (1) Plastic pipe must be designed in accordance with §192.121, and the design pressure for PE and PA pipe must be limited by §192.123.
- (2) See temperature limitations for thermoplastic material in §192.513(d).
- (3) Refer to §192.503(c) for limitation when testing with air, natural gas, or inert gas. Limited also to the design pressure of service line component (§192.619).
- (4) See 9.2 of the guide material under §192.321.
- (5) Apply 2.5 x design pressures for PE or PA pipe using a design factor of 0.40
- (6) Recommended practice is a minimum of 10 psig.
- (7) Whenever test pressure stresses pipe to 20% SMYS or more, see §§192.507 and 192.511(c) for additional requirements. Note that a service line stressed to 20% or more of SMYS is required by §192.511(c) to be tested per §192.507, even if the transmission line to which it is attached has been tested per §192.505.
- (8) See §192.619 for Class 1 and Class 2 locations.
- (9) Duration determined by volumetric content of test section, test medium, test pressure, thermal effects, leak criteria, and instrumentation in order to ensure discovery of all potentially hazardous leaks. See 2 of the guide material under §192.509.
- (10) See 5 of the guide material under §192.513.

2 TESTING SERVICE LINES EQUIPPED WITH EXCESS FLOW VALVES

2.1 *Pressurizing the service line.*

When pressurizing a service line equipped with an excess flow valve (EFV) during either testing or service activation, the operator should introduce either the test medium or gas at a flow rate that does not activate the EFV. EFV activation may be indicated by a sudden increase in pressure as noted on a pressure gauge at the injection point or the lack of a rapid buildup of pressure at the service line riser. If activated, bypass-type EFVs (EFVB) should reset automatically; non-bypass types (EFVNB) should be reset following their manufacturers' instructions.

2.2 *Testing the EFV.*

Prior to service line testing or service activation, the operator may opt to test the EFV for shutoff by first introducing the test medium at a high flow rate. If the EFV does not operate as designed, it should be replaced.

GUIDE MATERIAL APPENDIX G-192-11

(See guide material under §§192.3, 192.503, 192.557, 192.615, 192.703, 192.706, 192.723, and 192.941)

GAS LEAKAGE CONTROL GUIDELINES FOR NATURAL GAS SYSTEMS (METHANE)

(See Guide Material Appendix G-192-11A for petroleum gas systems)

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GUIDE MATERIAL APPENDIX G-192-11

(See guide material under §§192.3, 192.503, 192.557, 192.615, 192.703, 192.706, 192.723, and 192.941)

GAS LEAKAGE CONTROL GUIDELINES FOR NATURAL GAS SYSTEMS (METHANE)

(See Guide Material Appendix G-192-11A for petroleum gas systems)

1 SCOPE

These guidelines provide criteria for the detection, grading, and control of gas leakage and related records for systems transporting natural gas.

2 GENERAL DISCUSSION

- (a) A separate set of guidelines for natural gas system leakage surveys has been developed because of the differing physical properties of petroleum gases and natural gas.
- (b) When considering gas leakage detection and control, the two most significant differences between natural gas and petroleum gas vapor are their specific gravities and flammable limits. The specific gravity of natural gas is approximately 0.6 which is, therefore, lighter than air. This property facilitates the venting and dissipation of natural gas leakage into the atmosphere.
- (c) The flammable range of natural gas is approximately 5% to 15% gas in air, compared to approximately 2% to 10% gas in air for petroleum gases. However, this range will vary based on the composition of the gas mixture. The higher the BTU content of the gas, the lower the LEL. Pipeline quality gas is usually a mixture consisting predominantly of Methane with varying concentrations of Ethane, Propane, Butane, and other gases (e.g., Carbon Monoxide, Argon, other trace gases). When concentrations of gases from various sources change the overall mixture, either increasing or lowering the BTU content, the LEL and UEL will also shift.

SIGNIFICANT PHYSICAL PROPERTIES OF NATURAL GAS	
Formula	Mixture
Normal State @ atmospheric pressure @ 60 °F	Gas
Specific Gravity (Air = 1)	0.6
Flammability Limits – see Note 1	
Lower limit % Gas in Air	5
Upper limit % Gas in Air	15
<p><i>Note:</i></p> <p>Other mixtures including natural gas mixed with petroleum gas/air, and gases such as renewable natural gas, might have significantly different physical properties. The operator should evaluate the gas being transported and react accordingly (e.g., gas detector selection, modification of procedures).</p>	

TABLE 1

3 DEFINITIONS (Applicable to Guide Material Appendix G-192-11 Only)

Barhole is a hole that is made in the soil or paving for the specific purpose of testing the subsurface atmosphere with a CGI.

Barholing means the placement of sample points or test holes.

Building is any structure which is normally or occasionally entered by humans for business, residential or other purposes, and in which gas could accumulate.

Combustible gas indicator (CGI) is a device capable of detecting and measuring gas concentrations (of the gas being transported) in the atmosphere.

Confined space is any subsurface structure (e.g., vaults, tunnels, catch basins, manholes) of sufficient size to accommodate a person, and in which gas could accumulate.

Follow-up inspection is an inspection performed, after a repair has been completed, to determine the effectiveness of the repair.

Gas associated substructure is a device or facility utilized by an operator (e.g., a valve box, vault, test box, vented casing pipe) which is not intended for storing, transmitting or distributing gas.

L.E.L. is the lower explosive limit of the gas being transported.

Natural gas is a mixture of gases that is primarily methane and is lighter than air.

Prompt-action is dispatching qualified personnel without delay for the purpose of evaluating and, where necessary, abating the existing or probable hazard.

Reading is a repeatable deviation on a CGI or equivalent instrument, expressed in LEL. Where the reading is in an unvented confined space, consideration should be given to the rate of dissipation when the space is ventilated, and the rate of accumulation when the space is resealed.

Small substructures (other than gas associated substructures) are any subsurface structures that are of insufficient size to accommodate a person (e.g., telephone and electrical ducts and conduit, non-gas-associated valve and meter boxes), and in which gas could accumulate or migrate.

Tunnel is a subsurface passageway large enough for a person to enter and in which gas could accumulate.

UEL is the upper explosive limit of the gas being transported.

4 LEAKAGE DETECTION

This manual process is usually performed at the time of detection by the person performing the leak detection survey or investigation.

Note: See use of barhole in 5.3(a), (b), and (j)(7) and 5.4(k) below.

4.1 *Qualification of personnel.*

For leak surveys, use personnel who are:

- (a) Qualified (see Subpart N) in the type of survey being performed.
- (b) Familiar with the characteristics of the gas in the system.
- (c) Trained in the use of leak detection instruments.

4.2 *Reports from outside sources.*

Any notification from an outside source (e.g., police or fire department, other utility, contractor, customer or general public) reporting an odor, leak, explosion or fire, which may involve gas pipelines or other gas facilities, should be investigated promptly. If the investigation reveals a leak, the leak should be graded and action should be taken in accordance with these guidelines.

4.3 *Odors or indications from foreign sources.*

When leak indications (e.g., gasoline vapors, natural, petroleum, sewer or marsh gas) are found to originate from a foreign source or facility, or customer-owned piping, prompt actions should be taken where necessary to protect life and property. Potentially hazardous leaks should be reported promptly to the operator of the facility, and where appropriate, to the police department, fire department, or other governmental agency. When the operator's pipeline is connected to a foreign facility (e.g., the customer's piping), necessary action should be taken to eliminate the potential hazard, such as disconnecting or

shutting off the flow of gas to the facility.

4.4 Leak surveys and test methods.

For leak surveys, see the limitations under §§192.706 and 192.723 regarding leak detection equipment. The following gas leak surveys and test methods may be employed, as applicable, in accordance with written procedures.

- Surface Gas Detection Survey
- Subsurface Gas Detection Survey (including barhole surveys)
- Vegetation Survey
- Pressure Drop Test
- Bubble Leakage Test

Other survey and test methods may be employed if they are deemed appropriate and are conducted in accordance with procedures that have been tested and proven to be at least equal to the methods listed in this section.

(a) Surface Gas Detection Survey.

- (1) *Definition.* A continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to above-ground gas facilities with a gas detector system capable of detecting a concentration of 50 ppm gas in air.
- (2) *Procedure.* Equipment used to perform these surveys may be portable or mobile. For buried piping, sampling of the atmosphere should, where practical, take place as close to ground surface as permitted by gas detector design, due to the potential for rapid diffusion of leaking gas to the atmosphere. In areas where the piping is under pavement, samplings should also be at curb line(s), available ground surface openings (e.g., manholes, catch basins, sewer, power, and telephone duct openings, fire and traffic signal boxes, cracks in the pavement or sidewalk) or other interfaces where the venting of gas is likely to occur. For exposed piping, sampling should be adjacent to the piping.
- (3) *Utilization.* The survey should be conducted at speeds slow enough to allow an adequate sample to be continuously obtained by placement of equipment intakes over the most logical venting locations, giving consideration to the location of gas facilities. Gas detector design or adverse conditions may limit the use of this survey method. Operators should consult with manufacturers for equipment restrictions or limitations. Some adverse conditions that may affect the venting of subsurface gas leaks are:
 - (i) Moisture. A high water table, tidal effects, or excessive moisture from rain may inhibit venting of the gas to atmosphere.
 - (ii) Frost. Where frost is present in the soil, leak diffusion patterns may change.
 - (iii) Ice and Snow Cover. Ice and snow cover may cause surface sealing, limiting the venting of gas to the atmosphere.
 - (iv) Wind. High or gusting winds may alter diffusion at the surface of the ground.

(b) Subsurface Gas Detection Survey.

- (1) *Definition.* The sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting 0.5% gas in air (10% of the LEL) at the sample point.
- (2) *Procedure.*
 - (i) The survey should be conducted by performing tests with a CGI in a series of available openings (confined spaces and small substructures) or barholes over, or adjacent to, the gas facility or both. The location of the gas facility and its proximity to buildings and other structures should be considered in the spacing of the sample points. Sampling points should be as close as possible to the main or pipeline, and never further than 15 feet laterally from the facility. Along the route of the main or pipeline, sampling points should be placed at half the distance between the pipeline and the nearest building wall, or at 30 feet, whichever is shorter, but, in no case need the spacing be less than 10 feet. The sampling pattern should include sample points adjacent to service taps, street intersections, and known branch connections, as well as over or adjacent to buried service lines at the building wall.
 - (ii) Underground conduit and sewer structures can provide unobstructed and interconnected

(or exclusive) migration paths toward buildings. If readings are found in these structures, further investigation should follow. See 5.3(j) below.

(3) *Utilization.*

- (i) Good judgment should be used to determine when available openings (e.g., manholes, vaults, valve boxes) are sufficient in number to provide an adequate survey. If necessary, additional sample points (barholes) should be made.
- (ii) Sampling points should be of sufficient depth to directly sample within the subsurface or substructure atmosphere and not be restricted by capping obstructions, such as paving, concrete, soil moisture or frost or surface sealing by ice or water.

(4) *Precaution.* When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation. (See 5.2(d) and 5.3 below.)

- (c) Vegetation Survey.
 - (1) *Definition.* Visual observations made to detect abnormal or unusual indications in vegetation.
 - (2) *Procedure.* All visual indications should be evaluated using a CGI. Personnel performing these surveys should have good all-around visibility of the area being surveyed and their speed of travel should be determined by taking into consideration the following.
 - (i) System layout.
 - (ii) Amount and type of vegetation.
 - (iii) Visibility conditions, such as lighting, reflected light, distortions, terrain or obstructions.
 - (3) *Utilization.*
 - (i) This survey method should be limited to areas where adequate vegetation growth is firmly established.
 - (ii) This survey should not be conducted under the following conditions.
 - (A) When soil moisture content is abnormally high.
 - (B) When vegetation is dormant.
 - (C) When vegetation is in an accelerated growth period, such as in early spring.
 - (iii) Other acceptable survey methods should be used for locations within a vegetation survey area where vegetation is not adequate to indicate the presence of leakage.
 - (iv) Vegetation surveys may also be employed to supplement surface and subsurface gas detection surveys utilizing appropriate leak detection equipment.
- (d) Pressure Drop Test.
 - (1) *Definition.* A test to determine if an isolated segment of pipeline loses pressure due to leakage.
 - (2) *Procedure.* Facilities selected for pressure drop tests should first be isolated and then tested. The following criteria should be considered in determining test parameters.
 - (i) Test Pressure. The pressure used to perform a pressure drop test on existing facilities solely for the purpose of detecting leakage should be at least equal to the operating pressure. A pressure test conducted for the purpose of line qualification or uprating must be performed in accordance with the requirements of Subparts J or K.
 - (ii) Test Medium. The test medium used must comply with the requirements of §192.503(b).
 - (iii) Test Duration. The duration of the test should be of sufficient length to detect leakage. The following should be considered in the determination of the duration.
 - (A) The volume under test.
 - (B) The time required for the test medium to become temperature stabilized.
 - (C) The sensitivity of the test instrument.
 - (3) *Utilization.* Pressure drop tests should be used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. Normally, this type of test will not provide a leak location. Therefore, facilities on which leakage is indicated may require further evaluation by another detection method in order that the leak may be located, evaluated, and graded.
- (e) Bubble Leakage Test.
 - (1) *Definition.* The application of a soap-water or other foam forming solutions on exposed piping to determine the existence of a leak.
 - (2) *Procedure.* The exposed piping systems should be reasonably cleaned and completely coated with the solution. Leak detection solution should not be harmful to gas piping. Leaks are indicated by the presence of bubbles.
 - (3) *Utilization.* This test method may be used for the following.
 - (i) Testing exposed aboveground portions of a system, such as meter set assemblies or exposed piping on bridge crossings.
 - (ii) Testing a tie-in joint or leak repair, which is not included in a pressure test.

4.5 *Selecting an instrument for the detection of gas.*

- (a) Operators should consider the following when selecting a detection instrument.
 - (1) Usage.
 - (i) Leak survey.
 - (ii) Leak investigation (first response).
 - (iii) Leak classification (barholing).
 - (iv) Pinpointing.
 - (2) Application.
 - (i) Distribution system leak survey.
 - (ii) Transmission line leak survey.
 - (iii) Emergency response.
 - (iv) Pinpointing.
 - (3) Limitations.
 - (i) Sensitivity.
 - (ii) Type of sample system.
 - (iii) Weather related issues, such as wind, moisture, frost, snow, and ice.
 - (iv) Any condition that may limit detection capability of instrument.
- (b) See Table 2 for a listing of available technologies.

4.6 *Maintenance of instruments.*

Each instrument used for leak detection and evaluation should be operated in accordance with the manufacturer's recommended operating instructions and:

- (a) Should be periodically "checked" while in use to ensure that the recommended voltage requirements are available.
- (b) Should be tested daily or prior to use to ensure proper operation, to ensure that the sampling system is free of leakage, and to ensure that the filters are not obstructing the sample flow.
- (c) Any instrument used for leak survey should be tested for operation at each start-up and periodically tested during a survey.

4.7 *Calibration of instruments.*

Each instrument used for leak detection and evaluation should be calibrated at the following times in accordance with the manufacturer's recommended calibration instructions.

- (a) After any repair or replacement of parts.
- (b) On a regular schedule giving consideration to the type and usage of the instrument involved. HFI systems and CGI instruments should be checked for calibration at least once each month while in use.
- (c) At any time it is suspected that the instrument's calibration has changed.

4.8 *CGI Usage*

- (a) Operators are cautioned that a CGI instrument is an indicator, not a combustible gas analyzer. The intent of a CGI is to identify a hazard for the first responder or leak detection technician to take appropriate action necessary to render a hazardous condition safe as quickly as practicable.
- (b) The use of a CGI calibrated for the gas or vapor being tested is essential for accurate readings.

5 LEAK INVESTIGATION AND CLASSIFICATION

5.1 *Scope.*

- (a) Leak investigation and leak classification provide a means for determining the location, extent, and potential hazard of migrating gas. A leak investigation should be initiated to address a report of a possible leak indication. Prompt action should be taken as necessary for protection of people first and then property. Leak indications may include the following.
 - (1) Odor complaints.
 - (2) Reports of dead or discolored vegetation.

- (3) Positive readings from leak detection equipment.
- (b) Leak indications may originate from the following.
 - (1) Scheduled leak surveys.
 - (2) Line patrols.
 - (3) Customer reports.
 - (4) Reports from the general public.
 - (5) Notifications from local emergency responders.

- (c) Regardless of their origin, leak indications should be investigated promptly to identify any hazardous condition.
- (d) In any leak investigation, an operator should presume that a Grade 1 or hazardous leak might exist.
- (e) Only after completing the leak investigation should an operator determine an appropriate leak classification. Leak indications may be from sources other than natural gas.

5.2 Procedural Guidance – General.

- (a) The following guide material is not intended to be step by step procedure in responding to leak calls but is intended to assist operators in developing their own written procedures. Certain actions may be initiated ahead of other action items based on conditions at the leak location.
- (b) There are situations that warrant entering a building before checking the extent of gas migration. These situations might include the following.
 - (1) Broken main, service line, or customer owned fuel line.
 - (2) Gas blowing out of the ground.
 - (3) Hissing, roaring, or other sounds indicating gas leakage.
 - (4) Noticeable odor levels upon entry of a building.
 - (5) Noticeable odor levels outside a building.
 - (6) Gas in multiple underground structures that are normally connected by ducts or piping to houses, especially when the gas readings are high.
 - (7) Inside odor reports in an area of underground leakage or coincident with outside odor reports.

Note: If a gas reading at or above hazardous concentration level or an operator established criteria is detected, the operator should consider evacuating the structure. Calling for additional resources might be necessary based on the type of building involved in the leak call (e.g., hospital, school, commercial building). The operator should also consider shutting down the gas supply upstream of the identified leak location to stop the flow of gas into the ground where an underground gas migration may cause an imminent safety threat.

- (c) Where a leak indication appears to originate from buried piping, operator personnel should identify the extent of gas migration. If the migration pattern extends to nearby structures, the structures should be immediately checked for the presence of combustible gases. Structures may include buildings, confined spaces, and other buried utilities. Considerations should include the following.
 - (1) Based on the local conditions, structures beyond the identified migration pattern may also need to be checked.
 - (2) The levels of gas migrating into buildings need to be monitored so that the "make safe" actions can be initiated at appropriate times. Under these and similar conditions, it is recommended that immediate assistance be requested and the inside investigations be initiated without delay, including finding the farthest extent of gas migration.
 - (3) Because leakage can be dynamic, the gas levels in nearby buildings need to be continually monitored. It is not uncommon, under extreme conditions, for buildings that had no gas detected during the initial check to have gas levels found upon subsequent checks.
 - (4) Re-entry, by qualified personnel, to any structure within the boundaries of gas migration should be performed with extreme caution.
- (d) Personnel investigating a leak indication reported as either an "inside" or "outside" call should perform a visual check for the existence of other underground utilities in the area. Examples of other underground facilities in the area of suspected gas migration include the following.
 - (1) Customer-owned service lines.
 - (2) Buried fuel lines.
 - (3) Electric lines.
 - (4) Telephone wiring.
 - (5) Television cables.
 - (6) Water or sewer lines.
- (e) Consider the potential for gas migration under fully paved areas, ground frost, or buildings.
- (f) Barholing should be part of a leak investigation. See 5.3 below for guidelines for barholing.
- (g) If the leak investigation is initiated by an outside odor complaint, see 5.3 below.
- (h) If the leak investigation is initiated by an inside odor complaint, see 5.4 below.

- (i) If a leak investigation is conducted where non-typical soil conditions exist, see 5.5 below.

5.3 Procedural Guidance – Outside underground leak.

- (a) Using a barhole device and CGI, the operator should barhole in the area of indication along and adjacent to operator's mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. If there is an outside meter in the suspected leakage area, the operator should attempt to barhole between the service riser and the foundational wall. If there is an inside meter, the operator should attempt to barhole near the suspected location of service entry point at the foundational wall. Look for previous markouts or other indicators that might identify the point of entry. If a hazardous condition is detected or discovered during a leak investigation, see 5.2(b) above.

Note: If the leakage pattern extends outside the wall of a structure, the leakage investigation should continue to the inside of the structure.

- (b) Use caution when barholing to avoid damage to operator facilities or other underground structures. The operator should attempt to identify, where practicable, other underground facilities and avoid barholing directly over operator piping, customer-owned piping, and identified or suspected underground facilities.
- (c) Barholing of an underground leak indication should be done in a uniform manner by pushing or manually driving the barhole in the soil. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Operators might consider establishing a maximum barhole depth based on the depth of the operator and other facilities. However, under certain soil and environmental conditions (e.g., clay type soils, frost conditions), it may be necessary to barhole deeper than the established recommended maximum barhole depth. Once the area of the leak indication is determined, the operator should barhole and sample with the CGI in all directions from the approximate center of the leak until zero-gas readings are detected.
- (d) If a meter set is outside, observe its dial for unusual flow.
- (e) Look for indications of construction activity, which might have caused damage to the operator's facilities. Examples are:
 - (1) Excavation.
 - (2) Pavement patches.
 - (3) Landscaping.
 - (4) Fencing installation.
 - (5) Directional drilling or boring activity.
 - (6) Settling or subsidence.
- (f) Look for building additions that may have been constructed over natural gas service lines.
- (g) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak.
- (h) Check available openings in the area of a leak indication. These openings may include the following.
 - (1) Valve boxes.
 - (2) Catch basins.
 - (3) Manholes.
 - (4) Vaults.
 - (5) Water meter boxes.
 - (6) Pits.
 - (7) Underground irrigation control boxes.
 - (8) Other openings that allow access to underground atmospheres.
- (i) Check for migration along other buried utilities that may serve as a path for leaking gas. Paths for leaking gas might include the following.
 - (1) Sanitary sewer systems.
 - (2) Drains and drainage systems.
 - (3) Water mains and service lines.
 - (4) Telephone lines.
 - (5) Electric lines.

- (6) Cable TV lines.
- (j) Investigating readings in underground conduit structures.
 - (1) Underground conduits (e.g., electric, telephone, cable) or sewer and drain structures (e.g., storm, sanitary, catch basins, vent boxes) can provide unobstructed and interconnected (or exclusive) migration paths for gas. Therefore, if readings are found in these types of structures, the operator should conduct successive checks of all interconnecting manholes until zero readings are found.
 - (2) Buildings should also be checked to determine if interconnecting conduits are entering buildings and possibly providing migration of gas to the inside of the building. The investigation may require coverage of numerous blocks and buildings to achieve proper results.
 - (3) To determine which manholes are "interconnected," an operator can perform a survey of available openings, noting similarly identified manhole covers. Other techniques include the following.
 - (i) Contact and work with the owner-utility directly, or through one-call (observing local one-call laws).
 - (ii) Pull the manhole covers and observe (from the surface) the apparent directions of the conduits.

Note: Rectangular lids are common in the electrical industry. Opening this style of lid can cause damage if the lid drops through the opening. Use extreme caution when opening these lids or ask the owner-utility for assistance.
 - (4) After identifying all successive manholes with positive readings and the clear manholes at the ends, all gas facilities between the clear manholes should be considered to be within the area of migration and should be investigated.
 - (5) Due to prevailing air flow within conduit systems, it is not unusual for gas leaks to be closer to manholes with zero readings than those with positive readings.
 - (6) Ventilate all manholes. This should reduce readings in manholes that are farther from the leak source.

Note: This action can change the pattern of air flow within the conduit system and change readings inside buildings (if conduits connect to the adjacent buildings). Therefore, check buildings as discussed in 5.3(i)(2) above to determine if this should be a concern.
 - (7) Continue to pinpoint (see 7 below) the leak by barholing as described in the beginning of this section (5.3). If necessary, barhole over or near the conduit to obtain a lead to the source leak. Be cautious of other owner-utilities as discussed in 7.3(a).
- (k) If a leak area involves multiple buildings, the leak investigation area should be expanded to include each building in the affected area. Consider extending the leak investigation area one or two buildings, or a specified distance, beyond the leak migration area.
- (l) If a leak is detected on aboveground exposed piping, perform a bubble test using a leak detection solution to determine the magnitude of the leak. See 4.4(e) above.
- (m) Based on the leak location, extent of migration, and leak magnitude, assign a leak classification to the leak area. See Tables 3a, 3b, and 3c.

5.4 Procedural Guidance – Inside leak or odor complaint.

- (a) It may be necessary to investigate a reported leak or gas odor inside a structure. These investigations may result from the following.
 - (1) Gas migration.
 - (2) Indications of gas readings inside a building while performing routine leak surveys.
 - (3) Odor complaints.
 - (4) Notification from local emergency responders.

Note: If a hazardous condition is detected or discovered during a leak investigation, see 5.2(b) above.
- (b) Leaks may originate on customer-owned piping or equipment.
- (c) Look for indications of construction activity, which might have caused damage to the operator's facilities. Examples are:
 - (1) Excavation.
 - (2) Pavement patches.

- (3) Landscaping.
- (4) Fencing installation.
- (5) Directional drilling or boring activity.
- (6) Settling or subsidence.
- (d) Look for building additions that may have been constructed over natural gas service lines.
- (e) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak. See 5.3 above.
- (f) The CGI and an approved flashlight should be turned on prior to entering any building or structure.
- (g) If there is an outside meter set, observe its dial for excessive flow or movement.
- (h) Using a CGI, test around the entry door for gas indications. Do not ring the doorbell; knock on the door to get the attention of occupants. Upon entry do not operate any lights, but do take appropriate precautions to prevent accidental ignition. Immediately sample the inside atmosphere for the presence of a combustible gas. Natural gas is lighter than air and will accumulate near ceilings or in higher floors. Petroleum gas is heavier than air and will accumulate in the low atmosphere. If a gas reading at or above a hazardous concentration or an operator-established criteria is detected, the operator should consider evacuating the structure. Calling for additional resources might be necessary based on the type of building involved in the leak call (e.g., hospital, school, commercial building).

Note: If gas is detected, the applicable portions of the operator's emergency procedures need to be implemented (§192.615(a)(3)).

- (i) If the call is an odor complaint, proceed to the area indicated by the caller/occupant to investigate. When entering a building as a result of detecting a leak on outside underground piping, initiate an "inside" investigation. If the visit is in response to an odor complaint, attempt to locate and identify all gas lines associated with the building to their respective points of termination or equipment connection. Observe for abandoned or inactive natural gas lines, and natural gas lines that may exist under a portion of the structure that has no basement (e.g., an addition, garage).
- (j) If the building has a basement, enter it while continuously sampling with a CGI. Proceed to check the following with the CGI.
 - (1) Basement wall that is adjacent to the outside leak area for migration of gas.
 - (2) Gas piping that passes through basement walls.
 - (3) Cracks in basement walls.
 - (4) Other utility entry points, floor drains, laundry sink drains, bathroom drains, and toilets for the presence of combustible gases.
 - (5) Basement walls adjacent to buried gas piping.
- (k) If the structure has no basement, but has a crawlspace, attempt to gain access to the crawlspace and sample its atmosphere for the presence of combustible gases. If the structure is built on a concrete slab, check all utility penetration points for gas indications. Attempt to barhole at an angle under the concrete slab along the leak area and near utility entrances for gas indications.
- (l) Use the CGI and a leak detection solution to locate the source of the gas odor, and to identify the degree of potential hazard.
- (m) Using a barhole device and CGI, the operator should barhole in the area of indication along and adjacent to operator's mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. If there is an outside meter in the suspected leakage area, the operator should attempt to barhole between the service riser and the foundational wall. Look for previous markouts or other indicators that might identify the point of entry.

Note: If the leakage pattern extends to the outside wall of a structure, the leak investigation should continue to the inside of the structure.

 - (1) Use caution when barholing to avoid damages to operator facilities or other underground structures. The operator should attempt to identify, where practicable, other underground facilities and avoid barholing directly over operator piping, customer-owned piping, and other identified suspected underground facilities.
 - (2) Barholing of an underground leak indication should be done in a uniform manner by pushing or manually driving the barhole device into the soil. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Operators might consider establishing

a recommended maximum barhole depth based upon the depth of the operator facilities. However, under certain soil and environmental conditions (e.g., clay-type soils, frost conditions), it might be necessary to barhole deeper than the established recommended maximum barhole depth. Once the area of leak indication is determined, the operator should barhole and sample with a CGI in all directions from the approximate center of the leak until zero-gas readings are detected.

- (n) The operator should consider leak testing accessible gas piping, including abandoned or inactive lines, using a CGI or leak detection solution.
- (o) Where an operator's written procedures do not require an instrument leak test of customer-owned piping, consider performing a pressure-drop test or a meter dial test.

5.5 Procedural Guidance – Leak investigation and emergency response where non-typical soil conditions exist.

Note: See 5.2, 5.3, and 5.4 above for standard leak investigation procedures.

- (a) It is sometimes necessary to conduct leak investigations where non-typical soil conditions exist (e.g., water-saturated ground, frozen ground). If in the preliminary investigation it is determined that natural gas is involved, use equipment and resources available to identify the extent of gas migration and buildings that are at risk as quickly and efficiently as possible.
- (b) The operator should consider the tools and technology available to improve leak investigations during inclement weather, such as the following.
 - (1) Remote laser technology.
 - (2) Mobile leakage detection.
 - (3) Barhole equipment capable of sampling to the depth of the main.
 - (4) Powered barhole equipment for moisture saturated soils, frost, or pavement.
- (c) The operator should attempt to identify issues with gas migration under conditions such as:
 - (1) Water-saturated soil.
 - (2) Frost or frozen ground.
 - (3) Flooding.
 - (4) Snow or ice.
 - (5) Environmental or weather-related conditions that will limit venting and affect gas migration.
- (d) Survey techniques.
 - (1) Use survey or leak investigation techniques that address the potential for undetected gas migration. Under normal soil conditions, natural gas tends to migrate in all directions away from the leak. Subsurface construction will also influence the extent of gas migration, especially underground utilities that use granular backfill such as sewers, water mains, or other subsurface disturbances that create a "ditch line" effect on gas migration. Similarly, driveways and walkways constructed with crushed stone often provide a low-resistance path for migrating gas to follow.

In addition, certain soils and fill materials will influence the migration and venting of gas such as heavy clay soils versus coarse gravel. Gas will also accumulate in areas of granular backfill around foundation walls, footings, and concrete slab construction. Once gas has migrated to a foundation, footing, or slab, natural pressure differential between the atmosphere in the building and the surrounding soil will often enhance the entry of gas into the building.

- (2) When using a remote laser type detector to survey buildings for the presence of gas, consider checking areas such as the following.
 - (i) Inside crawlspaces and around foundation vents.
 - (ii) Around the perimeter of buildings that have no basement or crawlspace.
 - (iii) Any area of a building where potential gas is likely to vent (e.g., foundation sill plate, appliance and roof vents, windows and window frames, door frames, soffit).
- (3) Regardless of the prevailing weather conditions, the operator should consider using mobile leakage detection units to increase detection capability in the immediate area of the reported event.

Note: Review manufacturer's operating instructions regarding weather-related limitations.

- (4) Where standing water and saturated soil conditions are present:

- (i) Attempt to barhole away from the standing water in areas where gas is likely to migrate or vent, such as the following.
 - (A) Along the edges of areas of standing water.
 - (B) Along the edges of concrete slabs, concrete footings, or foundation walls.
 - (C) Adjacent to utility poles where there may be less soil moisture.
 - (D) Expansion seams in paved areas.
 - (E) Along other underground utilities and at underground utility entry points to buildings.
- (ii) Barhole deeper than normal to create a sample space at the top of the barhole above the water level.
- (iii) Observe for bubbling or bubbles in standing water, especially around any building or structures.
- (iv) Use water traps and filters to prevent damage to leakage detection equipment.
- (5) The operator should attempt to gain access to buildings in the area of suspected gas migration. Note that some operators place the responsibility of entering gas-filled buildings on local emergency responders. Using advanced leakage detection technology, portable infrared laser detectors, or other ppm-capable detection equipment, check for the presence of gas within:
 - (i) Buildings.
 - (ii) Basements.
 - (iii) Crawlspace (no basement).
 - (iv) Utility entrance points, where the building is constructed on a concrete slab (no basement).
- (6) If a building has a basement, check for gas venting from floor drains, seams and cracks in foundation walls, and utility entrances (e.g., gas, water, sewer, electric, telephone, cable).
- (7) For buildings with a crawlspace, test for the presence of gas at crawlspace vents.
- (8) For buildings built on a concrete slab, test for the presence of gas inside the building at cracks and seams in the slab and at utility entrances (e.g., gas, water, sewer, electric, telephone, cable). Check meter or valve boxes, as appropriate, where gas might be present. Some buildings constructed on a slab have a central vent system that can be checked for the presence of gas.
- (e) Ventilate, evacuate, monitor, and isolate.

If buildings are in the suspected area of migration, consider:

 - (1) Following operator written procedures regarding emergency response, including use of ventilation or evacuation. If detected gas readings are in the flammable range or above, ventilation may not be an option.
 - (2) Installing ventilation trenches between the suspected source and adjacent buildings.
 - (3) Aspirating gas from the ground.
 - (4) Eliminating potential sources of ignition in area (e.g., electric, telephone, cable).
 - (5) Continuously monitoring buildings in the suspected area of migration.
 - (6) Isolating gas supply to the area until conditions improve and resources are available to do a more thorough investigation (e.g., pinpointing, isolation, pressure testing).

5.6 Leak grades.

Based on an evaluation of the location or magnitude of a leak or both, one of the following leak grades should be assigned, thereby establishing the leak repair priority.

- (a) *Grade 1*, a leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. See §192.703(c).
- (b) *Grade 2*, a leak that is recognized as being non-hazardous at the time of detection, but, requires scheduled repair based on probable future hazard.
- (c) *Grade 3*, a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

5.7 Leak classification and action criteria.

Guidelines for leak classification and leakage control are provided in Tables 3a, 3b, and 3c. The examples of leak conditions provided in the tables are presented as guidelines and are not exclusive. The judgment of the operator personnel at the scene is of primary importance in determining the grade assigned to a leak.

5.8 *Temporary mitigative measures for Grade 1 leaks.*

Note: See GMA G-192-8 for additional information on leak classification and reinspection guidelines.

- (a) Temporary mitigative measures (e.g., venting, shutting down the line, reducing pressure, installing a temporary leak clamp) might be necessary to control the hazard of a leak until a permanent repair can be made.
- (b) A frequency of inspection should be established to verify that these measures are effectively mitigating the hazard until the leak is repaired.
- (c) If it is not feasible to make a permanent repair at the time of discovery, then a permanent repair should be made as soon as practicable.

5.9 *Follow-up inspection.*

The adequacy of leak repairs should be checked before backfilling. The perimeter of the leak area should be checked with a CGI. Where there is residual gas in the ground after the repair of a Grade 1 leak, follow-up inspections should be made as soon as practical after allowing the soil atmosphere to vent and stabilize, but, in no case later than one month following the repair. In the case of other leak repairs, the need for a follow-up inspection should be determined by qualified personnel.

5.10 *Reevaluation of a leak.*

When a leak is to be reevaluated (see Tables 3b and 3c), it should be classified using the same criteria as when the leak was first discovered.

6 RECORDS AND SELF-AUDIT GUIDELINES

6.1 *Leak records.*

Historical gas leak records should be maintained. Sufficient data should be available to provide the information needed to complete the Department of Transportation Leak Report Forms DOT F-7100.1, DOT F-7100.1-1, DOT F-7100.2 and DOT F-7100.2-1, and to demonstrate the adequacy of operator's maintenance programs.

The following data should be recorded and maintained, but need not be in any specific format or retained at one location. Time of day and environmental description records are required only for those leaks that are reported by an outside source or require reporting to a regulatory agency.

- (a) Date discovered, time reported, time dispatched, time investigated and by whom.
- (b) Date(s) reevaluated before repair and by whom.
- (c) Date repaired, time repaired and by whom.
- (d) Date(s) rechecked after repair and by whom.
- (e) If a reportable leak, date and time of telephone report to regulatory authority and by whom.
- (f) Location of leak.
- (g) Leak grade.
- (h) Line use (distribution, transmission, etc.).
- (i) Method of leak detection (if reported by outside party, list name and address).
- (j) Part of system where leak occurred (main, service line, etc.).
- (k) Part of system that leaked (pipe, valve, fitting, compressor or regulator station, etc.).
- (l) Material which leaked (steel, plastic, cast iron, etc.).
- (m) Origin of leak.
- (n) Pipe description.
- (o) Type repair.
- (p) Leak cause.
- (q) Date pipe installed (if known).
- (r) Under cathodic protection? (Yes — No).
- (s) Magnitude of CGI indication.

6.2 *Leak survey records.*

For the current and immediately previous survey of an area, the following information should be available.

- (a) Description of system and area surveyed. (This could include maps or leak survey logs or both.)
- (b) Survey results.
- (c) Survey method.
- (d) Names of those making survey.
- (e) Survey dates.
- (f) In addition to the above, the following records should be kept for a pressure drop test.
 - (1) The name of the operator, the name of the operator's employee responsible for making the test, and the name of any test company used.
 - (2) Test medium used.
 - (3) Test pressure.
 - (4) Test duration.
 - (5) Pressure recording charts, or other record of pressure readings.
 - (6) Test results.

6.3 Self audits.

In order that the completeness and effectiveness of the leak detection and repair program may be evaluated, self-audits should be performed on the following.

- (a) Schedule of leak survey. The operator should ensure that the schedule is commensurate with Subpart M, and the general condition of the pipeline system.
- (b) Survey completeness. The operator should ensure that records, such as maps, provided to the leak surveyor are sufficiently complete to meet the leak survey requirements. The following are examples that may be considered when evaluating survey completeness.
 - (1) Tagging (e.g., using a two-part numbered tag) will help document completion of the leak survey in a given area.
 - (i) Place tags on selected meter sets in the survey area ahead of the scheduled leak survey.
 - (ii) Meter tags should be dated when placed.
 - (iii) Survey technicians should then be required to return collected tags at the conclusion of the survey day.
 - (2) GPS tracking. Real-time GPS tracking of leak survey progress and completion can be plotted on system maps.
- (c) Survey effectiveness. The operator should evaluate leak survey results to ensure that, throughout the system, an effective leakage survey is being performed. The following are examples that may be considered for this evaluation.
 - (1) Leakage survey audits. Leakage survey audits may include a re-inspection of selected areas on a percentage basis (e.g., 10% of a given map area), by another survey technician, a supervisor, or a third-party using the same equipment. Audits should be concluded as soon as possible after the completion of the original survey to avoid variations in venting conditions. During an audit, classified leaks should be evaluated for the accuracy of classification according to the operator's written procedures.
 - (2) Detected leaks versus mechanical failure or damage. Evaluate variations in leakage data in areas where there is a likelihood of failure from system components (e.g., mechanical couplings or tees, risers), historical third-party damage, or outside forces (e.g., settling or subsidence). Evaluate both aboveground and underground leaks.
 - (3) Detected leaks versus corrosion data. Consider plotting leakage data in conjunction with corrosion data on protected and unprotected piping systems. An increase in corrosion-related leaks from one survey cycle to the next might indicate a significant change in the cathodic protection system on a given pipeline. Conversely, a reduction in reported corrosion-related leaks from one survey cycle to the next might indicate an issue with the performance of the survey.
 - (4) Detected leaks by area, map, town, mile, or pipe segment. Evaluate historical leak history data monthly for unanticipated variations in total leak count.
 - (5) Detected leaks versus confirmed leak calls from the public. Establish a matrix to evaluate the frequency of confirmed underground leaks reported by the public versus leaks detected during normal survey operations. This evaluation should take into account changes in the weather, system demand, and any condition that would cause an artificial increase in leak calls. Data

- collected for this type of evaluation may span a period of several years or survey cycles. A variance in the ratio may indicate improved or reduced effectiveness of the leak survey program.
- (6) Recheck program (e.g., 2 or 3 days). This can be used on leaks found during the survey to ensure that found leaks are being classified properly.
 - (d) Repair scheduling. The operator should ensure that repairs are made within the time specified.
 - (e) Repair effectiveness. The operator should ensure that leak repairs are effective.
 - (f) Leak records. The operator should ensure that adequate records are being maintained.

7 PINPOINTING

7.1 Scope.

Pinpointing is the process of tracing a detected gas leak to its source. It should follow an orderly systematic process that uses one or more of the following procedures to minimize excavation. The objective is to prevent unnecessary excavation which is more time consuming and costly than time spent pinpointing a leak.

When pinpointing a detected leak, barholes should be placed adjacent to the operator's piping. Powered barholing equipment (e.g., rotary hammer, drill) used in conjunction with a driving bar or barhole device may be necessary to complete the test hole in areas where piping is under pavement. In the process of pinpointing a leak for repair, it is typically necessary to barhole to the depth of or below the piping to detect the accumulation of gas in the soil.

7.2 Procedural Guidance.

- (a) The migration of gas should be determined by establishing the outer boundaries of the indications. This will define the area in which the leak will normally be located. These tests should be made with a CGI without expending excessive effort providing sample points.
- (b) In an urban environment, sampling is recommended at available openings (e.g., manholes, valve boxes) in the area. Testing such structures provides advantages in determining migration when pinpointing a leak, such as the following.
 - (1) Identifying the spread through efficient use of existing structures, thus minimizing barholes.
 - (2) Reducing the risk of damaging other utilities during the investigation.
 - (3) Expediting the investigation.
- (c) All gas lines should be located to narrow the area of search. Particular attention should be paid to the location of valves, fittings, tees, stubs, and connections, the latter having a relatively high probability of leakage. Caution should be exercised to prevent damage to other underground structures during barring or excavating.
- (d) Foreign facilities in the area of search should be identified. The operator should look for evidence of recent construction activities that could have contributed to the leakage. Gas may also migrate and vent along a trench or bore hole provided for other facilities. Leaks could occur at the intersection of the foreign facility and the gas pipeline. Particular attention should be given to these intersections.
- (e) Evenly spaced bar or test holes should be used over the gas line suspected to be leaking. All barholes should be of equal depth and diameter (and down to the pipe depth where necessary) and all CGI readings should be taken at an equal depth in order to obtain consistent and worthwhile readings. Using only the highest sustained readings, the gas can be traced to its source by identifying the test holes with the highest readings.
- (f) Frequently, high readings are found in more than one barhole and additional techniques are necessary to determine which reading is closest to the probable source. Many of the barhole readings will normally decline over a period of time but it may be desirable to dissipate excess gas from the underground locations to hasten this process. Evaluation methods should be used with caution to avoid distorting the venting patterns.
- (g) Once underground leakage has been identified, additional holes and deeper holes should be probed to more closely bracket the area. For example, test holes may be spaced six feet apart initially and then the six foot spacing between the two highest test holes might be probed with additional test holes, with spacing as close as twelve inches.

- (h) Additional tests include taking CGI readings at the top of a barhole or using manometer or bubble forming solution to determine which barhole has the greatest positive flow. Other indications are dust particles blowing from the barholes, the sound of gas coming from the barhole or the feel of gas flow on a sensitive skin surface. On occasion, sunlight refraction can be observed as the gas vents to the atmosphere.
- (i) Testing at available openings may be used to isolate the source in addition to the techniques previously mentioned. Many times the leak is found at the intersection of the foreign conduit and a gas line. Particular attention should be given to these locations.
- (j) Pinpointing a leak entering an underground conduit, sewer, or drain should require the investigation to extend to the first subsurface structure, in each direction, which has no readings. See 5.3(i) above.
- (k) When the pattern of the CGI readings has stabilized, the barhole with the highest reading will usually pinpoint the gas leak.
- (l) The operator should test with bubble forming solution where piping has been exposed, particularly to locate smaller leaks.

7.3 Precautions.

- (a) When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation.
- (b) Unusual situations may complicate these techniques on some occasions. They are unlikely, but possible. For example, multiple leakage can be occurring which gives confusing data. The area should be rechecked after repairs are completed to eliminate this potential. Gas may occasionally pocket and give a strong indication until the cavity has been vented. Foreign gases, such as gas from decomposed material, can occasionally be encountered. This is characterized by fairly constant CGI readings between 15% and 30% gas throughout the area. Indications of gas detected in sewer systems should be considered migrating gas leakage until proven otherwise by test or analysis.
- (c) When pinpointing leakage where the gas is heavier than air (LP gas), the gas will normally stay low near the pipe level, but may flow downhill. LP gases usually do not diffuse or migrate widely so the leak is generally close to the indication. If the gas is venting into a duct or sewer system, it can travel considerable distance.

TABLE 2 – AVAILABLE METHANE DETECTION TECHNOLOGIES

The following technologies are currently commercialized for use in methane leak detection. The information in the table depicts typical or nominal values / properties / characteristics contained in current manufacturers' literature. Operators should consult instrument manufacturers for appropriate application and limitations of available instrument technologies.

Technology	Typical Application	Sensitivity ^a	Range ^a	Sampling Method	Advantages	Limitations
Catalytic (Pellistor)	1	50 ppm 0.1-1% LEL 1% VOL	0.1-100% LEL	Vacuum pump Hand aspiration	Multi-gas options for confined space entry.	○ Sensors may be damaged by shock or vibration. ○ Loss of sensitivity when exposed to paint, lacquer, or varnish vapors.
Thermal Conductivity	1	2.5% VOL	0-100% VOL	Vacuum pump Hand aspiration	Multi-gas Capability.	○ Exposure to high concentrations may saturate the sensor.
Amplified Thermal Conductivity	1	5 ppm	5-1,000 ppm	Vacuum pump	Fast response.	○ Zero stability dependent on temperature and moisture. ○ Temperature change, dust, and moisture may cause false detection.
Semiconductor	2	1-100 ppm ^b	0-1,000 ppm	Diffusion	Fast response.	○ Zero stability dependent on temperature and moisture. ○ Can be damaged by water.

Table 2 Continued

TABLE 2 – AVAILABLE METHANE DETECTION TECHNOLOGIES (Continued)

Technology	Typical Application	Sensitivity ^a	Range ^a	Sampling Method	Advantages	Limitations
Flame Ionization	2, 3	1 ppm	0-10,000 ppm	Vacuum pump	Fast response. Vacuum pump system will draw residual gas from soil surface or cavity.	<ul style="list-style-type: none"> ○ Venturi draw systems are slower responding. ○ Will detect all volatile organic compounds (VOCs) unless special filters are used. ○ Requires external hydrogen fuel. ○ Calibration affected by temperature and humidity. ○ High concentration gas will cause sensor flame out. ○ Requires warm-up time to become stable.
Open Path IR TDLAS	2, 3 ^c , 4	5 ppm-meter	0-100,000 ppm-meter	Atmospheric open path laser scanning of up to 100 ft.	Remote detection of low leak levels, faster survey, improved operator safety, methane specific detection. Scanning of confined space without entry.	<ul style="list-style-type: none"> ○ Low flowing leaks may not produce a detectable plume.
Closed Path Bifringent IR	1 ^d , 2, 3	1 ppm	0-2,500 ppm 0-100% VOL ^b	Vacuum pump with sample cell	Low level leak detection, methane specific, no fuel gas, extended measurement range, very fast response.	<ul style="list-style-type: none"> ○ Requires warm-up time to reach full sensitivity.

Table 2 Continued

TABLE 2 – AVAILABLE METHANE DETECTION TECHNOLOGIES (Continued)

Technology	Typical Application	Sensitivity ^a	Range ^a	Sampling Method	Advantages	Limitations
Closed Path Bifringent IR (Continued)	3	1 ppm	0-250 ppm	Atmospheric closed path	Low level leak detection, methane specific, no fuel gas, fast mobile survey speed.	<ul style="list-style-type: none"> ○ Weather related conditions may affect detector (e.g., snow, sloppy road conditions). ○ Requires warm-up time to reach full sensitivity.
Closed Path IR Laser	1, 2, 3, 4	0.03 -100 ppm ^b	0-1,000 ppm 0-100% VOL	Vacuum pump with sample cell	Low level leak detection, methane specific, no fuel gas, extended measurement range.	<ul style="list-style-type: none"> ○ Dust contamination in sample cell will severely affect sensitivity. ○ Response rate and sensitivity vary by sample cell path length and flow design.
Open Path Passive IR Imaging	4	Unknown	N/A	Atmospheric open path	IR image of venting gas.	<ul style="list-style-type: none"> ○ Effective for moderate to large size leaks, difficult to image under certain ambient conditions.
<p>Notes:</p> <p>a - Specifications represent typical performance levels of the technology and implementation approach. Actual instrument specifications and performance may vary by manufacturer and product.</p> <p>b - Varies widely by manufacturer.</p> <p>c - Systems are currently under development. Currently in use on transmission line survey</p> <p>d - Systems are currently under development.</p>						

Applications Key

1. Leak investigation and classification. Typical instrument requirements are to measure percent gas or LEL to classify the severity of a leak. Instruments are typically rated "Intrinsically Safe." Typical measurement may be taken within a barhole or in the air of an area with a known leak.
2. Walking leak survey. Typical instrument requirements are to measure very low concentration levels with fast responding sensors. Typical measurements are taken while walking and searching with the instrument.
3. Mobile leak survey. Typical instrument requirements are to measure very low concentration levels with fast responding sensors. Typical measurements are taken while driving in a vehicle or ATV and searching with the instrument.
4. Gas gathering and production facilities, compressor station leak survey. Typical instrument requirements are to measure moderate to high concentrations from a remote distance.

Definitions

Open Path:	IR light passes through a naturally venting gas plume.
Closed Path:	IR light passes through sample chamber into which a vacuum pump draws gas.
Active IR:	IR beam is projected via a laser or other IR radiation source (e.g., LED, halogen lamp).
Passive IR:	IR light source is naturally occurring from sunlight or heat radiation.
Mid IR:	IR wavelengths in the 3-5 μm (μm is micro-meter).
Near IR:	IR wavelengths in the 0.8-2 μm .

Catalytic:

Catalytic works on the basis that gas molecules will combust when coming into contact with a heated platinum wire (coated with a catalytic material). The catalytic material will accelerate the oxidation reaction, thus raising the temperature of the platinum wire. As the platinum wire heats up, the change in resistance is measured. The amount of resistance change is proportional to the gas concentration. Typically, two sensor beads are used (sample and reference).

Thermal Conductivity:

Thermal conductivity works on the basis of passing a sample of gas over a heated thermistor. The thermistor will change resistance relative to the thermal conductivity of the gas. A reference thermistor is normally used to generate a relative comparison. The resistance change is proportional to the gas concentration.

Amplified Thermal Conductivity:

Amplified thermal conductivity is the same principle as "Thermal Conductivity" but with additional electronic amplification to increase the response signal.

Semiconductor:

Semiconductor sensors work on the basis that a tin dioxide (SnO_2) material (when heated to a specific temperature (e.g., at 400°C) for hydrocarbon detection) will change resistance as it interacts with the gas. The resistance change is non-proportional to gas concentration.

Flame Ionization:

Flame ionization works on the basis that gas molecules are positively charged by burning in a high temperature hydrogen flame. The ions are then collected on an electrode. The rate of charged particles collected is proportional to the gas concentration.

Open Path IR TDLAS (Tunable Diode Laser Absorption Spectroscopy):

Open path IR TDLAS works on the basis of an IR laser ($\sim 1.6\mu\text{m}$ for methane) sweeping through a naturally venting gas plume from a remote distance. As the IR laser passes through the plume, the gas will absorb a portion of the light. Absorption spectroscopy is used to measure the amount of absorption. The amount of absorption is proportional to the gas concentration and the path length through the gas.

Closed Path Biffringent IR:

Biffringent IR works on the basis that gas molecules absorb infrared light at specific wavelengths ($\sim 3.3\mu\text{m}$ for methane). A gas sample is passed through the light path in which a portion of the IR light is absorbed. Optical processing by a biffringent (Etalon) crystal is used to measure the amount of absorption. The amount of absorption is proportional to the gas concentration and the path length through the gas.

Closed Path IR Laser:

Closed path IR lasers work on the basis of passing a near IR laser tuned to a specific gas absorption wavelength ($\sim 1.6\mu\text{m}$) through a gas sample cell. The amount of absorption is proportional to the gas concentration and the path length through the gas. In order to increase the sensitivity, multiple passes through the cell are used to increase the path length. There are a number of laser, gas sample cell design, and signal processing approaches.

Open Path Passive IR Imaging:

IR Imaging works on the basis that gas molecules absorb infrared light at specific wavelengths ($3\text{-}5\mu\text{m}$). A gas imager uses a specialized set of lenses, IR filters, and photo detector array to measure the reduction of IR light relative to the background. A video image is then displayed. In some systems, additional post signal processing is used to enhance the contrast or to color the image.

TABLE 3a – LEAK CLASSIFICATION AND ACTION CRITERIA – GRADE 1

Grade	Definition	Action Criteria	Examples
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. See §192.703(c).	<p>Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous.</p> <p>*The prompt action in some instances may require one or more of the following.</p> <ul style="list-style-type: none"> a. Implementation of emergency plan (§192.615). b. Evacuating premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area by removing manhole covers, barholing, installing vent holes, or other means. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments. 	<ul style="list-style-type: none"> 1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. 2. Escaping gas that has ignited. 3. Any indication of gas which has migrated into or under a building, or into a tunnel. 4. Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. 5. Any reading of 80% LEL, or greater, in a confined space. 6. Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. 7. Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

TABLE 3b - LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 2

Grade	Definition	Action Criteria	Examples
2	<p>A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.</p>	<p>Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered.</p> <ul style="list-style-type: none"> a. Amount and migration of gas. b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type, and soil conditions, such as frost cap, moisture and natural venting. <p>Grade 2 leaks should be reevaluated at least once every six months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition.</p> <p>Grade 2 leaks may vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the above criteria, may justify scheduled repair within the next 5 working days. Others will justify repair within 30 days. During the working day on which the leak is discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repair.</p> <p>On the other hand, many Grade 2 leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic reinspection as necessary.</p>	<p><i>A. Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions.</i> Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building.</p> <p><i>B. Leaks Requiring Action Within Six Months</i></p> <ol style="list-style-type: none"> 1. Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak. 2. Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak. 3. Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. 4. Any reading between 20% LEL and 80% LEL in a confined space. 5. Any reading on a pipeline operating at 30% SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. 6. Any reading of 80% LEL, or greater, in gas associated substructures. 7. Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

TABLE 3c - LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 3			
Grade	Definition	Action Criteria	Examples
3	A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.	These leaks should be reevaluated during the next scheduled survey, or within 15 months of the date reported, whichever occurs first, until the leak is regraded or no longer results in a reading.	<p><i>Leaks Requiring Reevaluation at Periodic Intervals</i></p> <ol style="list-style-type: none"> 1. Any reading of less than 80% LEL in small gas associated substructures. 2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building. 3. Any reading of less than 20% LEL in a confined space.

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GUIDE MATERIAL APPENDIX G-192-11A

(See guide material under §§192.3, 192.11, 192.503 192.557, 192.615, 192.703, and 192.723)

GAS LEAKAGE CONTROL GUIDELINES FOR PETROLEUM GAS SYSTEMS

(See Guide Material Appendix G-192-11 for natural gas systems)

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GUIDE MATERIAL APPENDIX G-192-11A

(See guide material under §§192.3, 192.11, 192.503, 192.557, 192.615, 192.703, and 192.723)

GAS LEAKAGE CONTROL GUIDELINES FOR PETROLEUM GAS SYSTEMS

(See Guide Material Appendix G-192-11 for natural gas systems)

1 SCOPE

These guidelines provide criteria for the detection, grading, and control of gas leakage and for related records for systems transporting petroleum gases or petroleum gas/air mixtures that are heavier than air.

2 GENERAL DISCUSSION

- (a) A separate set of guidelines for petroleum gas system leakage surveys has been developed because of the differing physical properties of natural gas and petroleum gases.
- (b) When considering gas leakage detection and control, the two most significant differences between natural gas and petroleum gas vapor are their specific gravities and flammable limits. Petroleum gas vapor has a specific gravity range of 1.6 to 2.0 that is heavier than air. Therefore, when petroleum gas vapor escapes, it tends to settle in low places, and to move along the bottom of ditch lines and substructures unless dissipated by substantial air movement. It does not readily vent to the surface under normal conditions. When conducting tests for leakage on buried petroleum gas systems, it is essential that samples be taken at or near the pipe, in the bottom of ditch lines and at the low point of substructures.
- (c) Hazardous concentrations of petroleum gas can develop rapidly because of the relatively low LEL. The flammable range of natural gas is approximately 5% to 15% gas in air compared to approximately 2% to 10% gas in air for petroleum gases. Therefore, when conducting a petroleum gas system leak survey, it is essential to remember that the lower explosive limit can be as low as 1.9% gas in air. It is essential that Combustible Gas Indicator (CGI) instruments used to conduct petroleum gas leak surveys be properly calibrated. CGI instruments are discussed in more detail in 4.5, 4.6, and 4.7 below.

SIGNIFICANT PHYSICAL PROPERTIES OF TYPICAL HYDROCARBON GASES NORMALLY FOUND IN DISTRIBUTION AND PIPELINE SYSTEMS (See Note 1)			
	Propane	Propane / Air 40/60 Percent	Butane
Formula	C ₃ H ₈	C ₃ H ₈ / Air	C ₄ H ₁₀
Normal State @ atmospheric pressure @ 60 °F	Gas	Gas	Gas
Specific Gravity (Air = 1)	1.6	1.2	2.0
Flammability Limits			
Lower Limit Percent Gas in Air	2	2	2
Upper Limit Percent Gas in Air	10	10	9

TABLE 1

3 DEFINITIONS (Applicable to Guide Material Appendix G-192-11A Only)

Barhole is a hole that is made in the soil or paving for the specific purpose of testing the subsurface atmosphere with a CGI.

Building is any structure which is normally or occasionally entered by humans for business, residential or other purposes, and in which gas could accumulate.

Combustible gas indicator (CGI) is a device capable of detecting and measuring gas concentrations (of the gas being transported) in the atmosphere.

Confined space is any subsurface structure (e.g., vaults, tunnels, catch basin, manholes) of sufficient size to accommodate a person, and in which gas could accumulate.

Follow-up inspection is an inspection performed, after a repair has been completed, to determine the effectiveness of the repair.

Gas associated substructure is a device or facility utilized by an operator (e.g., a valve box, vault, test box, vented casing pipe) that is not intended for storing, transmitting or distributing gas.

L.E.L. is the *lower* explosive limit of the gas being transported.

Natural gas is a mixture of gases that is primarily methane and is lighter than air.

Permanent test point is a selected sample point that has been installed to maintain an opening for the testing of the subsurface atmosphere over or adjacent to the gas facility. Curb boxes, vents, or test inserts are normally used for this purpose.

Prompt-action is dispatching qualified personnel without delay for the purpose of evaluating and, where necessary, abating the existing or probable hazard.

Reading is a repeatable deviation on a CGI or equivalent instrument, expressed in LEL. Where the reading is in an unvented confined space, consideration should be given to the rate of dissipation when the space is ventilated, and the rate of accumulation when the space is resealed.

Small substructures (other than gas associated substructures) are any subsurface structures that are of insufficient size to accommodate a person (e.g., telephone and electrical ducts and conduit, non-gas-associated valve and meter boxes), and in which gas could accumulate or migrate.

Tunnel is a subsurface passageway large enough for a person to enter and in which gas could accumulate.

UEL is the upper explosive limit of the gas being transported.

4 LEAKAGE DETECTION

4.1 *Qualification of personnel.*

For leak surveys, use personnel who are:

- (a) Qualified (see Subpart N) in the type of survey being performed.
- (b) Familiar with the characteristics of the petroleum gas in the system.
- (c) Trained in the use of leak detection instruments.

4.2 *Reports from outside sources.*

Any notification from an outside source (e.g., police or fire department, other utility, contractor, customer or general public) reporting an odor, leak, explosion or fire, which may involve gas pipelines or other gas facilities, should be investigated promptly. If the investigation reveals a leak, the leak should be graded and action should be taken in accordance with these guidelines.

4.3 Odors or indications from foreign sources.

When leak indications (e.g., gasoline vapors, natural, petroleum, sewer or marsh gas) are found to originate from a foreign source or facility, or customer-owned piping, prompt actions should be taken where necessary to protect life and property. Potentially hazardous leaks should be reported promptly to the operator of the facility and, where appropriate, to the police department, fire department, or other governmental agency. When the operator's pipeline is connected to a foreign facility (e.g., the customer's piping) necessary action should be taken to eliminate the potential hazard, such as disconnecting or shutting off the flow of gas to the facility.

4.4 Leak surveys and test methods.

For leak surveys, see the limitations under §§192.706 and 192.723 regarding leak detection equipment. The following gas leak surveys and test methods may be employed, as applicable, in accordance with written procedures.

- Subsurface Gas Detection Survey (including barhole surveys)
- Pressure Drop Test
- Bubble Leakage Test

Other survey and test methods may be employed if they are deemed appropriate and are conducted in accordance with procedures that have been tested and proven to be at least equal to the methods listed in this section.

The Surface Gas Detection Survey and Vegetation Survey methods used for natural gas systems are not recommended for use on petroleum gas systems. Petroleum gases are heavier than air and will frequently not come to the ground surface or cause surface indications in the vegetation. However, the Surface Gas Detection Survey, when properly conducted by taking into account that the gas is heavier than air, may be used adjacent to above ground facilities.

(a) Subsurface Gas Detection Survey.

(1) *Definition.* The sampling of the subsurface atmosphere with a combustible gas indicator (CGI) or other device capable of detecting 0.2% gas in air (10% of the LEL) at the sample point.

(2) *Procedural Guidance.*

(i) The survey should be conducted by performing tests with a CGI in a series of available openings (confined spaces and small substructures) or barholes immediately adjacent to the gas facility. The following should be considered when selecting the placement of barholes and sample points.

- (A) The location of the gas pipelines and proximity to buildings or other structures.
- (B) Approximate depth of buried gas piping.
- (C) Extent of pavement.
- (D) Soil type and moisture content.
- (E) Available subsurface openings (e.g., valve boxes, catch basins, manholes).
- (F) Underground conduit and sewer structures can provide unobstructed and

interconnected (or exclusive) migration paths toward buildings. If readings are found in these structures, further investigation should follow. See 5.3(i) below.

(ii) Barhole sample points should be placed along or adjacent to the pipeline, to the approximate depth of the pipeline, and at intervals of 20 feet or less. The sampling pattern should include tests at the building wall at the service riser or point of service line entrance. Consideration should be given to threaded or mechanical joints that have had a history of leakage. Available subsurface openings adjacent to the pipeline should be tested. Where the piping system passes under pavement for a distance of 20 feet or less, barholes should be made at the point of entrance and exit of the paved area. Where the paved area over the pipeline is 20 feet or greater in length, sample points should be located at intervals of 20 feet or less. In the case of extensive pavement, permanent sample points should be considered.

(iii) When testing available openings for petroleum gas, readings should be taken at both the top and bottom of the structure. When testing larger confined spaces or basements, the floor areas, including floor drains, should be thoroughly tested because petroleum gases can lie

temporarily in pockets containing explosive mixtures. Since migrating gas may not enter at the pipeline entrance, a perimeter survey of the floors and walls is recommended. When conducting the survey, all barholes should penetrate to the pipe depth, where necessary, in order to obtain consistent and worthwhile readings. This includes penetrating through capping materials such as paving, concrete, frost, or surface sealing by ice or water. The required depth of the barhole will also depend upon the soil conditions, the depth of and pressure in the pipeline, and the type of instrument being used. The readings should be taken at the bottom of the bar. The probe used should be equipped with a device to preclude the drawing in of liquids. When conducting the survey, the inspector should use the most sensitive scale on the instrument, watching for small indications of combustible gas. Any indication should be further investigated to determine the source of the gas. Care should be taken to avoid damaging the pipe or coating with the probe bar.

- (3) *Utilization*. This survey method should be utilized for buried facilities. Good judgment should be used to determine when the recommended spacing of sample points is inadequate. Additional sample points should be provided under these conditions. Available openings (e.g., manholes, vaults, valve boxes) should be tested. However, they should not be relied upon as the only points used to test for petroleum gas leakage.
 - (4) *Precaution*. When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation. (See 5.2(e) and 5.3 below.)
- (b) Pressure Drop Test.
- (1) *Definition*. A test to determine if an isolated segment of pipeline loses pressure due to leakage.
 - (2) *Procedure*. Facilities selected for pressure drop tests should first be isolated and then tested. The following criteria should be considered in determining test parameters.
 - (i) Test Pressure. The pressure used to perform a pressure drop test on existing facilities solely for the purpose of detecting leakage should be at least equal to the operating pressure. A pressure test conducted for the purpose of line qualification or uprating must be performed in accordance with the requirements of Subparts J or K.
 - (ii) Test Medium. The test medium used must comply with the requirements of §192.503(b).
 - (iii) Test Duration. The duration of the test should be of sufficient length to detect leakage. The following should be considered in the determination of the duration.
 - (A) The volume under test.
 - (B) The time required for the test medium to become temperature stabilized.
 - (C) The sensitivity of the test instrument.
 - (3) *Utilization*. Pressure drop tests should be used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. Normally, this type of test will not provide a leak location. Therefore, facilities on which leakage is indicated may require further evaluation by another detection method in order that the leak may be located, evaluated, and graded.
- (c) Bubble Leakage Test.
- (1) *Definition*. The application of a soap-water or other foam-forming solutions on exposed piping to determine the existence of a leak.
 - (2) *Procedural Guidance*. The exposed piping systems should be reasonably cleaned and completely coated with the solution. Leak detection solution should not be harmful to gas piping. Leaks are indicated by the presence of bubbles.
 - (3) *Utilization*. This test method may be used for the following.
 - (i) Testing exposed aboveground portions of a system, such as meter set assemblies or exposed piping on bridge crossings.
 - (ii) Testing a tie-in joint or leak repair that is not included in a pressure test.

4.5 *Selecting an instrument for the detection of gas.*

(a) Operators should consider the following when selecting a detection instrument.

(1) Usage.

- (i) Leak survey.
- (ii) Leak investigation (first response).
- (iii) Leak classification (barholing).
- (iv) Pinpointing.

(2) Application.

- (i) Distribution system leak survey.
- (ii) Transmission line leak survey.
- (iii) Emergency response.
- (iv) Pinpointing.

(3) Limitations.

- (i) Sensitivity.
- (ii) Type of sample system.
- (iii) Weather related issues, such as wind, moisture, frost, snow, and ice.
- (iv) Any condition that may limit detection capability of instrument.

(b) See Table 2 for a listing of available technologies.

4.6 *Maintenance of instruments.*

Each instrument used for leak detection and evaluation should be operated in accordance with the manufacturer's recommended operating instructions and:

- (a) Should be periodically "checked" while in use to ensure that the recommended voltage requirements are available.
- (b) Should be tested daily or prior to use to ensure proper operation, to ensure that the sampling system is free of leakage, and to ensure that the filters are not obstructing the sample flow.
- (c) Any instrument used for leak survey should be tested for operation at each start-up and periodically tested during a survey.

4.7 *Calibration of instruments.*

Each instrument used for leak detection and evaluation should be calibrated at the following times in accordance with the manufacturer's recommended calibration instructions.

- (a) After any repair or replacement of parts.
- (b) On a regular schedule giving consideration to the type and usage of the instrument involved. HFI and CGI instruments should be checked for calibration at least once each month while in use.
- (c) At any time it is suspected that the instrument's calibration has changed.

4.8 *CGI Usage*

- (a) Operators are cautioned that a CGI instrument is an indicator, not a combustible gas analyzer. The intent of a CGI is to identify a hazard for the first responder or leak detection technician to take appropriate action necessary to render a hazardous condition safe as quickly as practicable.
- (b) The use of a CGI calibrated for the gas or vapor being tested is essential for accurate readings.

5 LEAK INVESTIGATION AND CLASSIFICATION

5.1 Scope.

- (a) Leak investigation and leak classification provide a means for determining the location, extent, and potential hazard of migrating gas. A leak investigation should be initiated to address a report of a possible leak indication. Prompt action should be taken as necessary for protection of people first and then property. Leak indications may include the following.
 - (1) Odor complaints.
 - (2) Reports of dead or discolored vegetation.
 - (3) Positive readings from leak detection equipment.
- (b) Leak indications may originate from the following.
 - (1) Scheduled leak surveys.
 - (2) Line patrols.
 - (3) Customer reports.
 - (4) Reports from the general public.
 - (5) Notifications from local emergency responders.
- (c) Regardless of their origin, leak indications should be investigated promptly to identify any hazardous condition.
- (d) In any leak investigation, an operator should presume that a Grade 1 or hazardous leak might exist.
- (e) Only after completing the leak investigation should an operator determine an appropriate leak classification. Leak indications may be from sources other than petroleum gas.

5.2 Procedural Guidance – General.

- (a) Petroleum gas is heavier than air, and will tend to migrate downward. Leaking petroleum gas will establish flow patterns that may follow utility trench lines and the natural topography of the leak area. Petroleum gas leak patterns will be affected by the presence of a perched water table in the leak area. The petroleum gas leak pattern will change or move with the water table due to seasonal changes. When investigating a petroleum gas leak, look for low spots or dips in the roadway and around the foundations of structures where the gas is likely to accumulate.
- (b) If a leak investigation is initiated by an inside odor complaint, see 5.4 below.
- (c) There are situations that might warrant entering a building before checking the extent of gas migration. These can include the following.
 - (1) Broken gas lines.
 - (2) Gas blowing out of the ground.
 - (3) Hissing, roaring, or other sounds indicating underground gas leakage.
 - (4) Noticeable odor levels.
 - (5) Gas in multiple underground structures that are normally connected by ducts or piping to houses, especially when the gas readings are high.
 - (6) Inside odor reports in an area of underground leakage or coincident with outside odor reports.
- (d) Where a leak indication appears to originate from buried piping, operator personnel should identify the extent of gas migration. If the migration pattern extends to nearby structures, the structures should be immediately checked for the presence of combustible gases. Structures may include buildings, confined spaces, and other sub-surface structures. See 5.3 below. Considerations should include the following.
 - (1) If gas is found within a structure, other structures within the boundaries of the migration pattern should be checked for the presence of gas. Based on the local conditions, structures beyond the identified migration pattern may also need to be checked.
 - (2) The levels of gas migrating into buildings need to be monitored so that the "make safe" actions can be initiated at appropriate times. Under these and similar conditions, it is recommended that immediate assistance be requested and the inside investigations be initiated without delay, including finding the farthest extent of gas migration.
 - (3) Because leakage can be dynamic, the gas levels in nearby buildings need to be continually monitored. It is not uncommon, under extreme conditions, for buildings that had no gas detected on the initial check to have gas levels found upon subsequent checks.

- (e) Personnel investigating a leak indication reported as either an "inside" or "outside" complaint should perform a visual check for the existence of other underground utilities in the area. If "outside," see 5.3 below. Examples of other underground facilities in the area of suspected gas migration include the following.
 - (1) Customer-owned service lines.
 - (2) Buried fuel lines.
 - (3) Electric lines.
 - (4) Telephone wiring.
 - (5) Television cables.
 - (6) Water or sewer lines.
- (f) Consider the potential for gas migration under fully paved areas, ground frost, or buildings.
- (g) Barholing should be a part of a leak investigation. See 5.3 below for guidelines for barholing.
- (h) If a leak investigation is conducted where non-typical soil conditions exist, see 5.5 below.

5.3 Procedural Guidance – Outside underground leak.

- (a) Using a barhole device and CGI, the operator should barhole in the area of leak indication along and adjacent to operator's mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. If there is an outside meter in the suspected leakage area, the operator should attempt to barhole between the service riser and the foundation wall. If there is an inside meter, the operator should attempt to barhole near the suspected location of the service entry point at the foundation wall. Look for previous markouts or other indicators that might identify the point of entry.

Note: If the leakage pattern extends to the outside wall of a structure, the leak investigation should continue to the inside of the structure.
- (b) Use caution when barholing to avoid damage to operator facilities or other underground structures. The operator should attempt to identify, where practicable, other underground facilities and avoid barholing directly over operator piping, customer-owned piping, and other identified or suspected underground facilities.
- (c) Barholing of an underground leak indication should be done in a uniform manner by pushing or manually driving the barhole into the soil. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Operators might consider establishing a recommended maximum barhole depth based upon the depth of operator and other facilities. However, under certain soil and environmental conditions (e.g., clay-type soils, frost conditions), it might be necessary to barhole deeper than the established recommended maximum barhole depth. Barholes should be placed to the approximate depth of the operator's piping. Once the area of the leak indication is determined, the operator should barhole and sample with the CGI in all directions from the approximate center of the leak until zero-gas readings are detected.
- (d) If a meter set is outside, observe its dial for unusual flow.
- (e) Look for indications of construction activity that might have caused damage to the operator's facilities. Examples are:
 - (1) Excavation.
 - (2) Pavement patches.
 - (3) Landscaping.
 - (4) Fencing installation.
 - (5) Directional drilling or boring activity.
 - (6) Settling or subsidence.
- (f) Look for building additions that may have been constructed over petroleum gas service lines.
- (g) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak.

- (h) Check available openings in the area of a leak indication. These openings may include the following.
- (1) Valve boxes.
 - (2) Catch basins.
 - (3) Manholes.
 - (4) Vaults.
 - (5) Water meter boxes.
 - (6) Pits.
 - (7) Underground irrigation control boxes.
 - (8) Other openings that allow access to underground atmospheres.
- (i) Check for migration along other buried utilities that may serve as a path for leaking gas. Paths for leaking gas might include the following.
- (1) Sanitary sewer systems.
 - (2) Drains and drainage systems.
 - (3) Water mains and service lines.
 - (4) Telephone lines.
 - (5) Electric lines.
 - (6) Cable TV lines.
- (j) Investigating readings in underground conduit structures.
- (1) Underground conduits (e.g., electric, telephone, cable) or sewer and drain structures (e.g., storm, sanitary, catch basins, vent boxes) can provide unobstructed and interconnected (or exclusive) migration paths for gas. Therefore, if readings are found in these types of structures, the operator should conduct successive checks of all interconnecting manholes until zero readings are found.
 - (2) Buildings should also be checked to determine if interconnecting conduits are entering buildings and possibly providing migration of gas to the inside of the building. The investigation may require coverage of numerous blocks and buildings to achieve proper results.
 - (3) To determine which manholes are "interconnected," an operator can perform a survey of available openings, noting similarly identified manhole covers. Other techniques include the following.
 - (i) Contact and work with the owner-utility directly, or through one-call (observing local one-call laws).
 - (ii) Pull the manhole covers and observe (from the surface) the apparent directions of the conduits.

Note: Rectangular lids are common in the electrical industry. Opening this style of lid can cause damage if the lid drops through the opening. Use extreme caution when opening these lids or ask the owner-utility for assistance.
 - (4) After identifying all successive manholes with positive readings and the clear manholes at the ends, all gas facilities between the clear manholes should be considered to be within the area of migration and should be investigated.
 - (5) Due to prevailing air flow within conduit systems, it is not unusual for gas leaks to be closer to manholes with zero readings than those with positive readings.
 - (6) Ventilate all manholes. This should reduce readings in manholes that are farther from the leak source,

Note: This action can change the pattern of air flow within the conduit system and change readings inside buildings (if conduits connect to the adjacent buildings). Therefore, check buildings as discussed in 5.3(i)(2) above to determine if this should be a concern.
 - (7) Continue to pinpoint (see 7 below) the leak by barholing as described in the beginning of this section (5.3). If necessary, barhole over or near the conduit to obtain a lead to the source leak. Be cautious of other owner-utilities as discussed in 7.3(a).
- (k) If a leak area involves multiple buildings, the leak investigation area should be expanded to include each building in the affected area. Consider extending the leak investigation area one or two buildings, or a specified distance, beyond the leak migration area.
- (l) If the leak is detected on aboveground exposed piping, perform a bubble test using a leak detection solution to determine the magnitude of the leak. See 4.4(b) above.

- (m) Based on the leak location, extent of migration, and magnitude, assign a leak classification to the leak area. See Tables 3a, 3b, and 3c.

5.4 Procedural Guidance – Inside leak or odor complaint.

- (a) It may be necessary to investigate a reported leak or gas odor inside a structure. These investigations may result from the following.
 - (1) Gas migration.
 - (2) Indications of gas readings inside a building while performing routine leak surveys.
 - (3) Odor complaints.
 - (4) Notification from local emergency responders.
- (b) Leaks may originate on customer-owned piping or equipment.
- (c) Look for indications of construction activity, which may have caused damage to the operator's facilities. Examples are:
 - (1) Excavation.
 - (2) Pavement patches.
 - (3) Landscaping.
 - (4) Fencing installation.
 - (5) Directional drilling or boring activity.
 - (6) Settling or subsidence.
- (d) Look for building additions that may have been constructed over petroleum gas service lines.
- (e) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak. See 5.3 above.
- (f) The CGI and an approved flashlight should be turned on prior to entering any building or structure.
- (g) If there is an outside meter set, observe its dial for excessive flow or movement.
- (h) Using a CGI, test around the entry door for gas indications. Do not ring the doorbell; knock on the door to get the attention of occupants. Upon entry do not operate any lights, but do take appropriate precautions to prevent accidental ignition. Immediately sample the inside atmosphere for the presence of combustible gas. Petroleum gas is heavier than air and will accumulate in the lower atmosphere.

Note: If gas is detected, the applicable portions of the operator's emergency procedures need to be implemented.
- (i) If the call is an odor complaint, proceed to the area indicated by the caller/occupant to investigate. When entering a building as a result of detecting a leak on outside underground piping, initiate an "inside" investigation. If the visit is in response to an odor complaint, attempt to locate and identify all gas lines associated with the building to their respective points of termination or equipment connection. Observe for abandoned or inactive petroleum gas lines, and petroleum gas lines that may exist under a portion of the structure that has no basement (e.g., an addition, garage).
- (j) If the building has a basement, enter it while continuously sampling with a CGI. Proceed to check the following with the CGI.
 - (1) Basement wall that is adjacent to the outside leak area for migration of gas.
 - (2) Gas piping that passes through basement walls.
 - (3) Cracks in basement walls.
 - (4) Other utility entry points, floor drains, laundry sink drains, bathroom drains, and toilets for the presence of combustible gases.
 - (5) Basement walls adjacent to buried gas piping.
- (k) If the structure has no basement, but has a crawlspace, attempt to gain access to the crawlspace and sample its atmosphere for the presence of combustible gases. If the structure is built on a concrete slab, check all utility penetration points for gas indications. Attempt to barhole at an angle under the concrete slab along the leak area and near utility entrances for gas indications.
- (l) Use the CGI and a leak detection solution to locate the source of the gas odor, and to identify the degree of potential hazard.
- (m) Using a barhole device and CGI, the operator should barhole in the area of indication along and adjacent to operator's mains and service lines, paying close attention to valves, service tees, fittings, stubs, connections, risers, or service entry points to buildings. If there is an outside meter in the

suspected leakage area, the operator should attempt to barhole between the service riser and the foundational wall. Look for previous markouts or other indicators that might identify the point of entry.
Note: If the leakage pattern extends to the outside wall of a structure, the leak investigation should continue to the inside of the structure.

- (1) Use caution when barholing to avoid damages to operator facilities or other underground structures. The operator should attempt to identify, where practicable, other underground facilities and avoid barholing directly over operator piping, customer-owned piping, and other identified suspected underground facilities.
- (2) Barholing of an underground leak indication should be done in a uniform manner by pushing or manually driving the barhole device into the soil. Barholes should be placed to a uniform depth and distance to adequately define the leak area. Operators might consider establishing a recommended maximum barhole depth based upon the depth of the operator facilities. However, under certain soil and environmental conditions (e.g., clay-type soils, frost conditions), it might be necessary to barhole deeper than the established recommended maximum barhole depth. Once the area of leak indication is determined, the operator should barhole and sample with a CGI in all directions from the approximate center of the leak until zero-gas readings are detected.
- (n) The operator should consider leak testing accessible gas piping, including abandoned or inactive lines, using a CGI or leak detection solution.
- (o) Where an operator's written procedures do not require an instrument leak test of customer-owned piping, consider a pressure-drop test or a meter dial test.

5.5 Leak investigation and emergency response where non-typical soil conditions exist.

Note: See 5.2, 5.3, and 5.4 above for standard leak investigation procedures.

- (a) It is sometimes necessary to conduct leak investigations during inclement weather. If in the preliminary investigation it is determined that petroleum gas is involved, use equipment and resources available to identify the extent of gas migration and buildings that are at risk as quickly and efficiently as possible.
- (b) The operator should consider the tools and technology available to improve leak investigations during inclement weather, such as the following.
 - (1) Detectors capable of detecting petroleum gases in the parts per million (ppm) detection range.
 - (2) Barhole equipment capable of sampling to the depth of the main.
 - (3) Powered barhole equipment for moisture saturated soils, frost, or pavement.
- (c) The operator should attempt to identify issues with gas migration under conditions such as:
 - (1) Water-saturated soil.
 - (2) Frost or frozen ground.
 - (3) Flooding.
 - (4) Snow or ice.
 - (5) Environmental or weather-related conditions that will limit venting and affect gas migration.
- (d) Survey techniques.
 - (1) Use survey or leak investigation techniques that address the potential for undetected gas migration. Under normal soil conditions, petroleum gas tends to migrate in all directions away from the leak. Subsurface construction will also influence the extent of gas migration, especially underground utilities that use granular backfill such as sewers, water mains, or other subsurface disturbances that create a "ditch line" effect on gas migration. Similarly, driveways and walkways constructed with crushed stone often provide a low-resistance path for migrating gas to follow.

In addition, certain soils and fill materials will influence the migration and venting of gas such as heavy clay soils versus coarse gravel. Petroleum gas will also accumulate in areas of granular backfill around foundation walls, footings, and concrete slab construction. Petroleum gas is heavier than air and will settle on top of a water table. Changes in the water table (increase) will bring residual petroleum gas to the surface and facilitate migration. Once gas has migrated to a foundation, footing, or slab, natural pressure differential between the

- atmosphere in the building and the surrounding soil will often enhance the entry of gas into the building.
- (2) When using a ppm-capable detector to survey buildings for the presence of gas, consider checking areas such as the following.
 - (i) Inside crawlspaces and around foundation vents.
 - (ii) Around the perimeter of buildings that have no basement or crawlspace.
 - (iii) Any area of a building where potential gas is likely to vent (e.g., foundation sill plate, appliance and roof vents, windows and window frames, door frames).
 - (3) Regardless of the prevailing weather conditions, the operator should expand the search area as quickly as practicable to include all buildings in the suspected area of migration.
 - (4) Where standing water and saturated soil conditions are present:
 - (i) Attempt to barhole away from the standing water in areas where gas is likely to migrate or vent, such as the following.
 - (A) Along the edges of areas of standing water.
 - (B) Along the edges of concrete slabs, concrete footings, or foundation walls.
 - (C) Adjacent to utility poles where there may be less soil moisture.
 - (D) Expansion seams in paved areas.
 - (E) Along other underground utilities and at underground utility entry points to buildings.
 - (ii) Barhole deeper than normal to create a sample space at the top of the barhole above the water level.
 - (iii) Observe for bubbling or bubbles in standing water, especially around any building or structures.
 - (iv) Use water traps and filters to prevent damage to leakage detection equipment.
 - (5) The operator should attempt to gain access to buildings in the area of suspected gas migration. Note that some operators place the responsibility of entering gas-filled buildings on local emergency responders. Using ppm-capable detection equipment, check for the presence of gas within:
 - (i) Buildings.
 - (ii) Basements.
 - (iii) Crawlspaces (no basement).
 - (iv) Utility entrance points, where the building is constructed on a concrete slab (no basement).
 - (6) If a building has a basement, check for gas venting from floor drains, seams and cracks in foundation walls, and utility entrances (e.g., gas, water, sewer, electric, telephone, cable).
 - (7) For buildings with a crawlspace, test for the presence of gas at crawlspace vents.
 - (8) For buildings built on a concrete slab, test for the presence of gas inside the building at cracks and seams in the slab and at utility entrances (e.g., gas, water, sewer, electric, telephone, cable). Check meter or valve boxes, as appropriate, where gas might be present. Some buildings constructed on a slab have a central vent system that can be checked for the presence of gas.
- (e) Ventilate, evacuate, monitor, and isolate.
- If buildings are in the suspected area of migration, consider:
- (1) Following operator written procedures regarding emergency response, including use of ventilation or evacuation. If detected gas readings are in the flammable range or above, ventilation may not be an option.
 - (2) Installing ventilation trenches between the suspected source and adjacent buildings.
 - (3) Aspirating gas from the ground.
 - (4) Eliminating potential sources of ignition in area (e.g., electric, telephone, cable).
 - (5) Continuously monitoring buildings in the suspected area of migration.
 - (6) Isolating gas supply to the area until conditions improve and resources are available to do a more thorough investigation (e.g., pinpointing, isolation, pressure testing).

5.6 Leak grades.

Based on an evaluation of the location or magnitude of a leak or both, one of the following leak grades

should be assigned, thereby establishing the leak repair priority.

- (a) *Grade 1*, a leak that represents an existing or probable hazard to persons or property and requires immediate repair or continuous action until the conditions are no longer hazardous. See §192.703(c).
- (b) *Grade 2*, a leak that is recognized as being non-hazardous at the time of detection, but, requires scheduled repair based on probable future hazard.
- (c) *Grade 3*, a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Because petroleum gas is heavier than air and will collect in low areas instead of dissipating, few leaks can safely be classified as Grade 3.

5.7 *Leak classification and action criteria.*

Guidelines for leak classification and leakage control are provided in Tables 3a, 3b, and 3c. The examples of leak conditions provided in the tables are presented as guidelines and are not exclusive. The judgment of the operator personnel at the scene is of primary importance in determining the grade assigned to a leak.

5.8 *Temporary mitigative measures for Grade 1 leaks.*

Note: See GMA G-192-8 for additional information on leak classification and reinspection guidelines.

- (a) Temporary mitigative measures (e.g., venting, shutting down the line, reducing pressure, installing a temporary leak clamp) might be necessary to control the hazard of a leak until a permanent repair can be made.
- (b) A frequency of inspection should be established to verify that these measures are effectively mitigating the hazard until the leak is repaired.
- (c) If it is not feasible to make a permanent repair at the time of discovery, then a permanent repair should be made as soon as practicable.

5.9 *Follow-up inspection.*

The adequacy of leak repairs should be checked before backfilling. The perimeter of the leak area should be checked with the CGI. Where there is residual gas in the ground after the repair of a Grade 1 leak, follow-up inspections should be made as soon as practical after allowing the soil atmosphere to vent and stabilize, but in no case later than one month following the repair. Since petroleum gases are heavier than air, it is usually necessary to purge or mechanically vent an area one or more times to ensure that a hazardous condition no longer exists. In the case of other repairs, the need for a follow-up inspection should be determined by qualified personnel and when a follow-up inspection is needed, it should be made as soon as practical, but in no case later than three months.

5.10 *Reevaluation of a leak.*

When a leak is to be reevaluated (see Tables 3b and 3c), it should be classified using the same criteria as when the leak was first discovered.

6 RECORDS AND SELF-AUDIT GUIDELINES

6.1 *Leak records.*

Historical gas leak records should be maintained. Sufficient data should be available to provide the information needed to complete the Department of Transportation Leak Report Forms DOT F-7100.1, DOT F-7100.1-1, DOT F-7100.2, and DOT F-7100.2.1 and to demonstrate the adequacy of the operator's maintenance programs.

The following data should be recorded and maintained, but need not be in any specific format or retained at one location. Time of day and environmental description records are required only for those leaks that are reported by an outside source or require reporting to a regulatory agency.

- (a) Date discovered, time reported, time dispatched, time investigated and by whom.
- (b) Date(s) reevaluated before repair and by whom.
- (c) Date repaired, time repaired and by whom.
- (d) Date(s) rechecked after repair and by whom.
- (e) If a reportable leak, date and time of telephone report to regulatory authority and by whom.

- (f) Location of leak.
- (g) Leak grade.
- (h) Line use (distribution, transmission, etc.).
- (i) Method of leak detection (if reported by outside party, list name and address).
- (j) Part of system where leak occurred (main, service line, etc.).
- (k) Part of system that leaked (pipe, valve, fitting, compressor or regulator station, etc.).
- (l) Material which leaked (steel, plastic, cast iron, etc.).
- (m) Origin of leak.
- (n) Pipe description.
- (o) Type repair.
- (p) Leak cause.
- (q) Date pipe installed (if known).
- (r) Under cathodic protection? (Yes — No).
- (s) Magnitude of CGI indication.

6.2 *Leak survey records.*

For the current and immediately previous survey of an area, the following information should be available.

- (a) Description of system and area surveyed. (This could include maps or leak survey logs or both.)
- (b) Survey results.
- (c) Survey method.
- (d) Names of those making survey.
- (e) Survey dates.
- (f) In addition to the above, the following records should be kept for a pressure drop test.
 - (1) The name of the operator, the name of the operator's employee responsible for making the test, and the name of any test company used.
 - (2) Test medium used.
 - (3) Test pressure.
 - (4) Test duration.
 - (5) Pressure recording charts, or other record of pressure readings.
 - (6) Test results.

6.3 *Self audits.*

In order that the completeness and effectiveness of the leak detection and repair program may be evaluated, self-audits should be performed on the following.

- (a) Schedule of leak survey. The operator should ensure that the schedule is commensurate with Subpart M, and the general condition of the pipeline system.
- (b) Survey completeness. The operator should ensure that records, such as maps, provided to the leak surveyor are sufficiently complete to meet the leak survey requirements. The following are examples that may be considered when evaluating survey completeness.
 - (1) Tagging (e.g., using a two-part numbered tag) will help document completion of the leak survey in a given area.
 - (i) Place tags on selected meter sets in the survey area ahead of the scheduled leak survey.
 - (ii) Meter tags should be dated when placed.
 - (iii) Survey technicians should then be required to return collected tags at the conclusion of the survey day.
 - (2) GPS tracking. Real-time GPS tracking of leak survey progress and completion can be plotted on system maps.
- (c) Survey effectiveness. The operator should evaluate leak survey results to ensure that, throughout the system, an effective leakage survey is being performed. The following are examples that may be considered for this evaluation.
 - (1) Leakage survey audits. Leakage survey audits may include a re-inspection of selected areas on a percentage basis (e.g., 10% of a given map area), by another survey technician, a supervisor, or a third-party using the same equipment. Audits should be concluded as soon as possible after the completion of the original survey to avoid variations in venting conditions. During an audit,

classified leaks should be evaluated for the accuracy of classification according to the operator's written procedures.

- (2) Detected leaks versus mechanical failure or damage. Evaluate variations in leakage data in areas where there is a likelihood of failure from system components (e.g., mechanical couplings or tees, risers), historical third-party damage, or outside forces (e.g., settling or subsidence). Evaluate both aboveground and underground leaks.
 - (3) Detected leaks versus corrosion data. Consider plotting leakage data in conjunction with corrosion data on protected and unprotected piping systems. An increase in corrosion-related leaks from one survey cycle to the next might indicate a significant change in the cathodic protection system on a given pipeline. Conversely, a reduction in reported corrosion-related leaks from one survey cycle to the next might indicate an issue with the performance of the survey.
 - (4) Detected leaks by area, map, town, mile, or pipe segment. Evaluate historical leak history data monthly for unanticipated variations in total leak count.
 - (5) Detected leaks versus confirmed leak calls from the public. Establish a matrix to evaluate the frequency of confirmed underground leaks reported by the public versus leaks detected during normal survey operations. This evaluation should take into account changes in the weather, system demand, and any condition that would cause an artificial increase in leak calls. Data collected for this type of evaluation may span a period of several years or survey cycles. A variance in the ratio may indicate improved or reduced effectiveness of the leak survey program.
 - (6) Recheck program (e.g., 2 or 3 days). This can be used on leaks found during the survey to ensure that found leaks are being classified properly.
- (d) Repair scheduling. The operator should ensure that repairs are made within the time specified.
 - (e) Repair effectiveness. The operator should ensure that leak repairs are effective.
 - (f) Leak records. The operator should ensure that adequate records are being maintained.

7 PINPOINTING

7.1 Scope.

Pinpointing is the process of tracing a detected gas leak to its source. It should follow an orderly systematic process that uses one or more of the following procedures to minimize excavation. The objective is to prevent unnecessary excavation which is more time consuming and costly than time spent pinpointing a leak.

7.2 Procedural Guidance.

- (a) The migration of gas should be determined by establishing the outer boundaries of the indications. This will define the area in which the leak will normally be located. These tests should be made with a CGI without expending excessive effort providing sample points.
- (b) In an urban environment, sampling is recommended at available openings (e.g., manholes, valve boxes) in the area. Testing such structures provides advantages in determining migration when pinpointing a leak, such as the following.
 - (1) Identifying the spread through efficient use of existing structures, thus minimizing barholes.
 - (2) Reducing the risk of damaging other utilities during the investigation.
 - (3) Expediting the investigation.
- (c) All gas lines should be located to narrow the area of search. Particular attention should be paid to the location of valves, fittings, tees, stubs, and connections, the latter having a relatively high probability of leakage. Caution should be exercised to prevent damage to other underground structures during barring or excavating.
- (d) Foreign facilities in the area of search should be identified. The operator should look for evidence of recent construction activities that could have contributed to the leakage. Gas may also migrate and vent along a trench or bore hole provided for other facilities. Leaks could occur at the intersection of the foreign facility and the gas pipeline. Particular attention should be given to these intersections.
- (e) Evenly spaced bar or test holes should be used over the gas line suspected to be leaking. All barholes should be of equal depth and diameter (and down to the pipe depth where necessary) and all CGI readings should be taken at an equal depth in order to obtain consistent and worthwhile readings. Using only the highest sustained readings, the gas can be traced to its source by identifying the test holes with the highest readings.
- (f) Frequently, high readings are found in more than one barhole and additional techniques are necessary to determine which reading is closest to the probable source. Many of the barhole readings will normally decline over a period of time but it may be desirable to dissipate excess gas from the underground locations to hasten this process. Evaluation methods should be used with caution to avoid distorting the venting patterns.
- (g) Once underground leakage has been identified, additional holes and deeper holes should be probed to more closely bracket the area. For example, test holes may be spaced six feet apart initially and then the six foot spacing between the two highest test holes might be probed with additional test holes, with spacing as close as twelve inches.
- (h) Additional tests include taking CGI readings at the top of a barhole or using manometer or bubble forming solutions to determine which barhole has the greatest positive flow. Other indications are dust particles blowing from the barholes, the sound of gas coming from the barhole or the feel of gas flow on a sensitive skin surface. On occasion, sunlight refraction can be observed as the gas vents to the atmosphere.
- (i) Testing at available openings may be used to isolate the source in addition to the techniques previously mentioned. Many times the leak is found at the intersection of the foreign conduit and the gas line. Particular attention should be given to these locations.
- (j) Pinpointing a leak entering an underground conduit, sewer, or drain may require the investigation to extend to the first subsurface structure, in each direction, which has no readings. See 5.3(i) above.

- (k) When the pattern of the CGI readings has stabilized, the barhole with the highest reading will usually pinpoint the gas leak.
- (l) The operator should test with bubble forming solution where piping has been exposed, particularly to locate smaller leaks.

7.3 Precautions.

- (a) When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation.
- (b) Unusual situations may complicate these techniques on some occasions. They are unlikely, but possible. For example, multiple leakage can be occurring which gives confusing data. The area should be rechecked after repairs are completed to eliminate this potential. Gas may occasionally pocket and give a strong indication until the cavity has been vented. Foreign gases, such as gas from decomposed material, can occasionally be encountered. This is characterized by fairly constant CGI readings between 15% and 30% gas throughout the area. Indications of gas detected in sewer systems should be considered migrating gas leakage until proven otherwise by test or analysis.
- (c) When pinpointing leakage where the gas is heavier than air (LP gas), the gas will normally stay low near the pipe level but may flow downhill. LP gases usually do not diffuse or migrate widely so the leak is generally close to the indication. If the gas is venting into a duct or sewer system, it can travel considerable distance.

TABLE 2 – AVAILABLE PROPANE GAS DETECTION TECHNOLOGIES

The following technologies are currently commercialized for use in propane leak detection. The information in the table depicts typical or nominal values / properties / characteristics contained in current manufacturers' literature. Operators should consult instrument manufacturers for appropriate application and limitations of available instrument technologies.

Technology	Typical Application	Sensitivity ^a	Range ^a	Sampling Method	Advantages	Limitations
Catalytic (Pellistor)	1	50 ppm 0.1-1% LEL 1% VOL	0.1-100% LEL	Vacuum pump Hand aspiration	Multi-gas options for confined space entry.	<ul style="list-style-type: none"> ○ Sensors may be damaged by shock or vibration. ○ Loss of sensitivity when exposed to paint, lacquer, or varnish vapors.
Thermal Conductivity	1	2.5% VOL	0-100% VOL	Vacuum pump Hand aspiration	Multi-gas capability.	<ul style="list-style-type: none"> ○ Exposure to high concentrations may saturate the sensor.
Amplified Thermal Conductivity	1	5 ppm	5-1,000 ppm	Vacuum pump	Fast response.	<ul style="list-style-type: none"> ○ Zero stability dependent on temperature and moisture. ○ Temperature change, dust, moisture may cause false detection.
Semiconductor	2	1-100 ppm ^b	0-1,000 ppm	Diffusion	Fast response.	<ul style="list-style-type: none"> ○ Zero stability dependent on temperature and moisture. ○ Can be damaged by water.

Table 2 Continued

TABLE 2 – AVAILABLE PROPANE GAS DETECTION TECHNOLOGIES (Continued)

Technology	Typical Application	Sensitivity ^a	Range ^a	Sampling Method	Advantages	Limitations
Flame Ionization	2	1 ppm	0-10,000 ppm	Vacuum pump	Fast response. Vacuum pump system will draw residual gas from soil surface or cavity.	<ul style="list-style-type: none"> ○ Venturi draw systems are slower responding. ○ Will detect all volatile organic compounds (VOCs) unless special filters are used. ○ Requires external hydrogen fuel. ○ Calibration affected by temperature and humidity. ○ High concentration gas will cause sensor flame out. ○ Requires warm-up time to become stable. ○ Should be used in conjunction with a barhole device and a soil sample probe.
<p><u>Notes:</u> a - Specifications represent typical performance levels of the technology and implementation approach. Actual instrument specifications and performance may vary by manufacturer and product. b - Varies widely by manufacturer.</p>						

Applications Key

1. Leak investigation and classification. Typical instrument requirements are to measure percent gas or LEL to classify the severity of a leak. Instruments are typically rated "Intrinsically Safe." Typical measurement may be taken within a barhole or in the air of an area with a known leak.
2. Barhole leak survey. Typical instruments are to measure very low concentration levels with fast responding sensors. Typical measurements are taken while using a barhole device and soil sample probe along the main or services.

Definitions

Catalytic:

Catalytic works on the basis that gas molecules will combust when coming into contact with a heated platinum wire (coated with a catalytic material). The catalytic material will accelerate the oxidation reaction, thus raising the temperature of the platinum wire. As the platinum wire heats up, the change in resistance is measured. The amount of resistance change is proportional to the gas concentration. Typically, two sensor beads are used (sample and reference).

Thermal Conductivity:

Thermal conductivity works on the basis of passing a sample of gas over a heated thermistor. The thermistor will change resistance relative to the thermal conductivity of the gas. A reference thermistor is normally used to generate a relative comparison. The resistance change is proportional to the gas concentration.

Amplified Thermal Conductivity:

Amplified thermal conductivity is the same principle as Thermal Conductivity, but with additional electronic amplification to increase the response signal.

Semiconductor:

Semiconductor sensors work on the basis that a tin dioxide (SnO_2) material (when heated to a specific temperature (e.g., at 400°C) for hydrocarbon detection) will change resistance as it interacts with the gas. The resistance change is non-proportional to gas concentration.

Flame Ionization:

Flame ionization works on the basis that gas molecules are positively charged by burning in a high temperature hydrogen flame. The ions are then collected on an electrode. The rate of charged particles collected is proportional to the gas concentration.

TABLE 3a — LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 1

Grade	Definition	Action Criteria	Examples
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. See §192.703(c).	<p>Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous.</p> <p>*The prompt action in some instances may require one or more of the following.</p> <ul style="list-style-type: none"> a. Implementation of emergency plan (§192.615). b. Evacuating premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments. 	<ul style="list-style-type: none"> 1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. 2. Escaping gas that has ignited. 3. Any indication of gas which has migrated into or under a building, or into a tunnel. 4. Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. 5. Any reading of 60% LEL, or greater, in a confined space. 6. Any reading of 60% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. 7. Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

TABLE 3b - LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 2

Grade	Definition	Action Criteria	Examples
2	<p>A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.</p>	<p>Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered.</p> <ul style="list-style-type: none"> a. Amount and migration of gas. b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type, and soil conditions, such as frost cap, moisture and natural venting. <p>Grade 2 leaks may vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the above criteria, may justify scheduled repair within the next 5 working days. During the working day on which the leak is discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repair.</p> <p>On the other hand, many Grade 2 leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic reinspection as necessary.</p> <p>Grade 2 leaks should be reevaluated at least once every 3 months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition.</p>	<p><i>A. Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions.</i> Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building.</p> <p><i>B. Leaks Requiring Action Within Six Months.</i></p> <ol style="list-style-type: none"> 1. Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak. 2. Any reading of 100% LEL, or greater, under a street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak. 3. Any reading less than 60% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. 4. Any reading less than 60% LEL in a confined space. 5. Any reading on a pipeline operating at 30% SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. 6. Any reading of 80% LEL, or greater, in gas associated substructures. 7. Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

TABLE 3c - LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 3			
Grade	Definition	Action Criteria	Examples
3	A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. Because petroleum gas is heavier than air and will collect in low areas instead of dissipating, few leaks can safely be classified as Grade 3.	<p>These leaks should be rechecked within 3 months of date reported to substantiate the grading.</p> <p>Thereafter, these leaks should be reevaluated during the next scheduled survey, or within 15 months of the date reported, whichever occurs first, until the leak is regraded or no longer results in a reading.</p>	<p><i>Leaks Requiring Reevaluation at Periodic Intervals</i></p> <ol style="list-style-type: none"> 1. Any reading of less than 80% LEL in small gas associated substructures. 2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building.

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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. (e.g., loss of embankment, loss of cover).
 - (5) Impacts of major storms.
 - (6) Potential dredging or anchoring activities and establishing a tolerance zone.
 - (7) Land-based warning signage for ships and boats.
- (b) The use of models, such as hydrologic or land mass movement, might be beneficial.
- (c) For information regarding protection of structures in navigable waters:
 - (1) National Research Council report, "Improving the Safety of Marine Pipelines" (1994), available from National Academies Press (NAP) at www.nap.edu/read/2347.
 - (2) Council for Dredging and Marine Construction Safety (<https://cdmcs.org>)
 - (3) Coastal and Marine Operators' Pipeline Industry Initiative (www.camogroup.org)
 - (4) NTSB Report MAR-21-05 available at www.nts.gov/investigations/AccidentReports/Reports/MAR2105.pdf.

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-192-15A

(See guide material under §§192.319, 192.361, and Guide Material Appendix G-192-6)

HORIZONTAL DIRECTIONAL DRILLING (HDD) FOR STEEL PIPELINES

Note: Guide material for HDD using plastic pipe is in Guide Material Appendix G-192-15B.

1 SCOPE

This guide material provides information for planning, design, and installation where using horizontal directional drilling (HDD) for both transmission and distribution steel pipelines. It is general in nature and contains references to recommended or standard practices. Specific stress calculations and other technical information are not included.

2 INTRODUCTION

2.1 *Overview and background.*

HDD has become the preferred method of many pipeline operators for the crossing of major rivers, roadways, and other construction obstacles. The benefits derived from HDD, and not opening a trench, include reduced environmental impact, minimal interference to surface traffic during construction, and pipeline protection in high surface-traffic areas after construction. Additional benefits are also realized in applications where surface and subsurface restoration costs are high.

2.2 *Description of HDD.*

The method typically uses a small diameter non-rotating drill stem to thrust-bore or jet-out a pilot hole that conforms to a crossing geometry. Next, back reaming is performed through the pilot hole (possibly, several passes may be required) to establish a diameter sufficient for the carrier pipe installation. The reamed hole should be somewhat in excess of the carrier pipe diameter. Drilling fluids are used to carry out spoil tailings, cool the drilling head, and help maintain the hole during drilling operations. The assembled and pre-tested pipe string is then pulled in to complete the operation.

3 PROJECT PLANNING

3.1 *Rights-of-way.*

To ensure adequate workspace and access, consideration should be given to the following.

- (a) Temporary work areas for the rig-side (drilling side) and pipe-side (pipe fabrication and testing side) work areas.
- (b) Ingress and egress to site.
- (c) Title survey to determine previous land uses.

3.2 *Design criteria.*

Essential planning considerations are as follows.

- (a) Develop an accurate cross-sectional profile of the proposed site to determine the lowest elevation for the pipeline to be installed. The profile should extend at least 300 feet beyond the proposed entry and exit points.
- (b) Determine the type of sub-soil to be encountered in the installation. If there is insufficient soil information available for the site, soil borings or seismic studies are recommended. Numerous soil borings may be necessary if gravel, boulders, or rocks are encountered. A minimum of two bores should be made at each side of a creek or waterway crossing.
- (c) Perform a hydrographic survey to determine the bottom profile of the waterway.

3.3 *Environmental considerations.*

Issues to consider regarding the environment include the following.

- (a) Federal, state, and local permits.
- (b) Containment, classification, and disposal of drilling mud and fluids.
- (c) Wetlands and storm water runoff.

3.4 *Alignment considerations.*

An important step in planning the HDD operation is to use the information from the previous steps, including the cross-sectional profile and the geotechnical information, to determine the optimum pipeline alignment and placement. An optimum location provides the minimum required pipeline cover in an ideal soil installation medium. A straight-line (horizontal) and smooth curvature (vertical) placement is important.

3.5 *Limits and obstructions.*

Obstructions that should be considered include the following.

- (a) Magnetic influences within 75 feet of the proposed bore path.
- (b) Buried or abandoned structures.
- (c) Utility infrastructure.
- (d) Underground or aboveground pipelines.
- (e) Overhead obstructions at the drill site or exit areas.
- (f) Geotechnical characteristics.

4 **GEOTECHNICAL INVESTIGATIONS**

4.1 *Planning soil investigation.*

The following are considerations in planning an investigative soil review.

- (a) Preliminary geological review of site records or existing topographic maps.
- (b) Number and locations of borings.
- (c) Depth of borings.

4.2 *Geotechnical report.*

A geotechnical report should include the results of the following.

- (a) Standard Classification of Soils — Reference ASTM D2487, "Standard Practice for Classification of Soils for Engineering Purposes (Unified Soil Classification System)."
- (b) Standard Penetration Test (SPT) — Reference ASTM D1586, "Standard Test Method for Standard Penetration Test (SPT) and Split-Barrel Sampling of Soils."
- (c) Thin-walled tube sampling.
- (d) Sieve analysis of granular materials.
- (e) Rock information.

5 **PIPE DESIGN CRITERIA**

5.1 *Design loads and pipe wall selection criteria.*

Design pressures in accordance with applicable codes and regulations usually determine the required wall thickness and specified minimum yield strength (SMYS) of the pipe.

5.2 *Stress calculations.*

- (a) Individual stresses (e.g., tensile, bending, hoop) and combined stresses are calculated for construction and in-service conditions and compared with allowable stress limits addressed in pipeline standards (see PRCI PR-277-144507, "Installation of Pipelines Using Horizontal Directional Drilling – An Engineering Design Guide").

- (b) The stresses of concern are due to the following.
 - (1) Spacing of fabrication and testing supports.
 - (2) Break-over curvature.
 - (3) Installation.
 - (i) Curvature along the drill path.
 - (A) Sag bends.
 - (B) Over bends.
 - (C) Side bends.
 - (ii) External pressure.
 - (A) Pull force that should include the weight of the pipe and the weight of water (when used to keep the pipe from floating), friction force from pulling over the support system, and the friction force generated between the pipe and drilling fluid.
 - (B) Installed force (i.e., the force required to pull the pipe through the hole), which is necessary to properly size the pulling equipment.
 - (4) Operating conditions.
 - (i) Internal pressure.
 - (ii) Elastic bending resulting from the pipe conforming to the geometry of the drilled hole.
 - (iii) Thermal stresses resulting from the differential between constructed and in-service temperatures.
- (c) The worst case condition for stress will generally be located at points where the greatest combination of tensile, bending, and hoop stresses occur simultaneously. At a minimum, the following points along the drill path should be analyzed for individual and combined stresses.
 - (1) Locations with tight radius bends.
 - (2) Locations with high tension levels, which typically are found near the drilling rig.
 - (3) The deepest point, which is subject to the greatest internal hydrostatic head.

5.3 Coating system considerations.

- (a) The following components should be considered for steel pipe to be installed by HDD.
 - (1) Abrasion-resistant overlay.
 - (2) Primary coating.
 - (3) Field joint coating.
 - (4) Coating thickness.
- (b) Design considerations for these coating systems might include the following.
 - (1) Site-specific geologic information.
 - (2) Level of required abrasion resistance.
 - (3) Adhesive properties.
 - (4) Gouge, impact, and penetration resistance.
 - (5) Flexibility.
- (c) The following coating systems may be recommended for HDD installations.
 - (1) Extra-thickness fusion bonded epoxy.
 - (2) Dual-powder fusion bonded epoxy.
 - (3) Epoxy-based polymer concrete.
 - (4) Polyurethane.
 - (5) Polyethylene / polypropylene (3-layer).
- (d) Before tie-in to the piping system, an assessment of the selected coating system may be made to establish cathodic protection current demand by performing one of the following.
 - (1) Pulling a sacrificial joint prior to pullback of the main pipe segment.
 - (2) Examining the initial joints of the main pipe string for coating damage at the exit location.
 - (3) Performing a current drain measurement across the bored section.

5.4 Nondestructive testing.

Consideration should be given to nondestructive testing of all circumferential welds.

5.5 Pipeline pressure testing.

A pre-installation test and post-installation test are recommended. The pre-installation test is to detect any material or fabrication defects while the pipe is above ground and can be easier and less costly repaired. The post-installation test is to confirm that the installed pipe is suitable for service.

6 CONSTRUCTION MONITORING

6.1 Instrumentation.

- (a) A surface monitoring system may be used to track the location of the down-hole probe during the pilot-hole drilling. The installer should ensure that such monitoring controls the drilling path accuracy and allows for necessary corrections.
- (b) Some form of gauging should be used to monitor the pulling force.

6.2 Construction inspection.

- (a) The installer's operations should be reviewed to ensure that the pipe pull section is adequately supported during pullback.
- (b) The pipe coating and the coated welds should be electronically inspected by "jeeping" prior to entering the reamed hole.
- (c) The proper containment and disposal of drilling mud or fluids should be verified to ensure compliance with applicable requirements.
- (d) Other considerations are as follows.
 - (1) Pipe handling during stringing, welding, and pullback operations.
 - (2) Pipeline testing process.
 - (3) Proper joint coating application.
 - (4) Pipe coating repairs.
 - (5) As-built profile for comparison with preliminary profile.
 - (6) Construction site security.

7 DAMAGE PREVENTION CONSIDERATIONS

See Guide Material Appendix G-192-6 for damage prevention considerations while performing directional drilling or using other trenchless technologies.

8 REFERENCES

- (a) ASTM D1586, "Standard Test Method for Standard Penetration Test (SPT) and Split-Barrel Sampling of Soils."
- (b) ASTM D2487, "Standard Practice for Classification of Soils for Engineering Purposes (Unified Soil Classification System)."
- (c) PRCI L51725, "Drilling Fluids in Pipeline Installation by Horizontal Directional Drilling-A Practical Applications Manual."
- (d) PRCI PR-277-144507, "Installation of Pipelines Using Horizontal Directional Drilling – An Engineering Design Guide."
- (e) "Guidelines for a Successful Directional Crossing Bid Package." Published by Directional Crossing Contractors Association, 1995.
- (f) "Horizontal Directional Drilling Good Practices Guidelines" – 2008 (3rd Edition) – North American Society for Trenchless Technology (NASTT).

GUIDE MATERIAL APPENDIX G-192-17

(See Part 191 and guide material under §§192.13, 192.603, 192.605, 192.941, and 192.947)

EXPLICIT REQUIREMENTS FOR REPORTS, INSPECTIONS, TESTS, WRITTEN PROCEDURES, RECORDS, OR SIMILAR ACTIONS

1 EXPLICIT REQUIREMENTS TABLE

Part 191 and Part 192 include requirements for reports, inspections, tests, written procedures, records, and similar actions on the part of the operator. The table in this Guide Material Appendix is a listing of each regulation section that clearly and precisely states such requirements and the actions to be taken. The operator is advised that other types of required actions are not intended to be included in this listing. The term "written" is only included in the "Requirements" column where explicitly used in the regulation section, even though it might be otherwise implied. The table does not include other requirements contained in documents that are incorporated by reference. This table is provided as an aid and does not remove operator responsibility concerning adherence to the Regulations, whether required, implied, prudent, or practical.

2 ADDITIONAL GUIDELINES FOR RECORD RETENTION AND SECURITY

2.1 Record Retention

The operator should consider the following.

- (a) Developing and maintaining written procedures regarding record retention.
- (b) Retaining records to support meaningful analysis for integrity management purposes beyond the minimum record retention intervals specified by regulation.

2.2 Security Considerations for Written and Digital Records

- (a) Written and digital records should be stored and maintained in a secure location or medium that reduces the risk of damage or deletion from theft, unauthorized access (e.g., insecure data, hacking), fire, or environmental issues (e.g., storm damage, flooding).
- (b) The operator should consider limiting access to records to only those persons authorized to access or make changes to stored records. Consider limiting access to digital records to personnel with "read-only" privileges.
- (c) Other considerations include the following.
 - (1) Storing copies of original written records in a separate location in the event of loss or damage.
 - (2) Copying written records to digital format for prolonged storage and security.
 - (3) Backing up digital records to a secure server or cloud on a regular basis.

Subpart	Section	Subject	Requirements	
Part 191	191.5	Telephonic notice of certain incidents	Notice	
	191.9	Distribution system: Incident report	Report	
	191.11	Distribution system: Annual report	Report	
	191.13	Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines	Report	
	191.15	Transmission and gathering systems: Incident report	Report	
	191.17	Transmission and gathering systems: Annual report	Report	
	191.25	Filing safety-related condition reports	Report	
General	A	192.9	Gathering line requirements	Inspection, test, written program, markers
		192.10	Outer continental shelf pipelines	Marker or schematic
		192.12	Underground natural gas storage facilities	Written procedures, integrity demonstration and verification, monitoring, records
		192.13	General requirements	Plans, procedures, programs, inspection, tests
		192.14(a), (b)	Conversion to gas service	Written procedures, inspection, test, records
		192.16	Customer notification	Notice, records

Table Continued

Subpart	Section	Subject	Requirements	
Materials	B	192.55(c)	Steel pipe	Visual examination, weldability test
		192.63	Marking of materials	Material marking
		192.67	Records: Material Properties	Material records
Pipe Design	C	192.107	Yield strength (S) for steel pipe	Tensile strength test
		192.112	Additional design requirements for steel pipe using alternative MAOP	Records
Design of Pipeline Components	D	192.144	Qualifying metallic components	Visual inspection
		192.145	Valves	Manufacturer's test
		192.149	Standard fittings	Prototype test
		192.150	Passage of internal inspection devices	Petition approval
		192.153	Components fabricated by welding	Test
		192.177(b) (4) & (5)	Additional provisions for bottle-type holders	Mill hydrostatic test, leak test
Welding of Steel in Pipelines	E	192.225	Welding procedures	Written procedures, tests, records
		192.227(b)	Qualification of welders and welding operators	Test
		192.227(c)	Individual welder qualification at time of construction of steel transmission line, and offshore and onshore Type A gathering line	Records
		192.229(c)	Limitations on welders and welding operators	Test
		192.241	Inspection and test of welds	Visual inspection, test
		192.243	Nondestructive testing	Written procedures, test, records
		192.245(b), (c)	Repair or removal of defects	Inspection, written procedures

Table Continued

Joining of Materials other than by Welding	F	192.273	General (Joining of materials other than by welding)	Written procedures, inspection
		192.281	Plastic pipe (electrofusion)	Test
		192.283	Plastic pipe: Qualifying joining procedures	Written procedures, various tests
		192.285	Plastic pipe: Qualifying persons to make joints	Inspection, test, examination, qualification method, records

Table Continued

Subpart	Section	Subject	Requirements	
General Construction Requirements for Transmission Lines and Mains	G	192.303	Compliance with specifications or standards	Written specifications or standards
		192.305	Inspection: General	Inspection
		192.307	Inspection of materials	Visual inspection
		192.313(b)	Bends and elbows (circumferential welds)	Test (nondestructive)
		192.328	Construction requirements for steel pipe using alternative MAOP	Records
Customer Meters, Service Regulators, and Service Lines	H	192.359(b)	Customer meter installations: Operating pressure	Test
		192.381	Service lines: Excess flow valve performance standards	Manufacturer's test, mark or identify
		192.383	Excess flow valve installation	Notification Report
Requirements for Corrosion Control	I	192.455(b), (c), (f)	External corrosion control: Buried or submerged pipelines installed after 07/31/71	Test, investigation
		192.457	External corrosion control: Buried or submerged pipelines installed before 08/1/71	Test
		192.459	External corrosion control: Examination of buried pipeline when exposed	Examination, investigation
		192.461(c)	External corrosion control: Protective coating	Inspection
		192.465	External corrosion control: Monitoring	Test, inspection, reevaluation, electrical survey
		192.467	External corrosion control: Electrical isolation	Inspection and test

Table Continued

Subpart	Section	Subject	Requirements	
Requirements for Corrosion Control (Continued)	I	192.473	External corrosion control: Interference currents	Program
		192.475	Internal corrosion control: General	Investigation, inspection
		192.476	Internal corrosion control: Design & construction of transmission line	Evaluation, records
		192.477	Internal corrosion control: Monitoring	Check
		192.479	Atmospheric corrosion control: General	Test, investigation
		192.481	Atmospheric corrosion control: Monitoring	Inspection
		192.490	Direct assessment	Assessment
		192.491	Corrosion control records	Records or maps
Test Requirements	J	192.503	Test requirements: General	Test
		192.505	Strength test requirements: Pipelines to operate at 30% or more of SMYS	Test, manufacturer certification
		192.507	Test requirements: Pipelines to operate at less than 30% of SMYS	Test, test procedure, leak test
		192.509	Test requirements: Pipelines to operate below 100 psig	Test procedure, leak test
		192.511	Test requirements: Service lines	Leak test
		192.513	Test requirements: Plastic pipelines	Test procedure, test
		192.517	Test requirements: Records	Records
Upgrading	K	192.553	Upgrading: General requirements	Records, written procedure, leak check
		192.555	Upgrading: Hoop stress at 30% or more of SMYS	Review, test (if necessary)
		192.557	Upgrading: Hoop stress at less than 30% of SMYS	Review, leak survey, test (if necessary)
Operations	L	192.603	General provisions (operations)	Records
		192.605	Procedural manual for operations, maintenance, and emergencies	Written procedures
		192.609	Change in class location: Required study	Study

Table Continued

Subpart	Section	Subject	Requirements	
Operations (Continued)	L	192.611	Change in class location: Confirmation or revision of MAOP	Test (if necessary)
		192.612	Underwater inspection: Gulf of Mexico	Written procedure, inspection, notification, mark
		192.613	Continuing surveillance	Written procedures
		192.614	Damage prevention program	Written program, notification, temporary marking, inspection, records
		192.615	Emergency plans	Written procedures, notification
		192.616	Public awareness	Written program, documentation, evaluation
		192.617	Investigation of failures	Written procedures
		192.620	Alternative MAOP for certain steel pipelines	Various (see §192.620)
		192.625	Odorization of gas	Sampling
		192.631	Control room management	Written procedures, written plan, program, records, documentation
Maintenance	M	192.705	Transmission lines: Patrolling	Program, patrols
		192.706	Transmission lines: Leakage surveys	Leak surveys
		192.707(a), (c)	Line markers	Markers
		192.709	Transmission lines: Record keeping	Records
		192.719	Transmission lines: Testing of repairs	Test, weld examination
		192.721	Distribution systems: Patrolling	Patrols
		192.723	Distribution systems: Leakage surveys	Program, leak surveys, test
		192.725	Test requirements for reinstating service lines	Test
		192.727(g)	Abandonment or deactivation of facilities	Report

Table Continued

Subpart	Section	Subject	Requirements	
Maintenance (Continued)	M	192.731	Compressor stations: Inspection and testing of relief devices	Inspection, test
		192.736	Compressor station: Gas detection	Test
		192.739	Pressure limiting and regulating stations: Inspection and testing	Inspection, test
		192.740	Pressure regulating, limiting and overpressure protection - Individual service lines directly connected to production, gathering, or transmission pipelines.	Inspection, test
		192.741(c)	Telemetry or recording gauges	Inspection
		192.743	Capacity of relief devices	Test or review/calculation
		192.745	Valve maintenance: Transmission lines	Inspection
		192.747	Valve maintenance: Distribution systems	Check, service
		192.749	Vault maintenance	Inspection
		192.751	Prevention of accidental ignition	Warning sign (if necessary)
Qualification of Pipeline Personnel	N	192.805	Qualification program	Written program
		192.807	Recordkeeping	Records
Gas Transmission Pipeline Integrity Management	O	192.905	Identifying high consequence areas (HCA)	Identification/evaluation
		192.907	Implementing Subpart O	Written program
		192.909	Changes to integrity management program (IMP)	Documentation, notification
		192.911	Elements of IMP	Program - 16 elements (see §192.911)
		192.913	Deviation of program from certain requirements	Demonstrate exceptional performance (see numerous actions in §192.913(b))

Table Continued

Subpart	Section	Subject	Requirements
Gas Transmission Pipeline Integrity Management (Continued)	192.915	Knowledge and training of IMP personnel	Program provisions – Address 3 primary areas regarding personnel (see §192.915)
	192.917	Identifying/addressing potential threats to pipeline integrity	Identify/address threats (see numerous actions in §192.917)
	192.919	Baseline assessment plan	Written plan – Address 5 elements (see §192.919)
	192.921	Conducting baseline assessment	Method selection, assessment
	192.923	Direct assessment	Plans
	192.925	External Corrosion Direct Assessment (ECDA) requirements	Plan/procedures – 4 separate steps (see §192.925)
	192.927	Internal Corrosion Direct Assessment (ICDA) requirements	Plan – 4 separate parts (see §192.927)
	192.929	Stress Corrosion Cracking Direct Assessment (SCCDA) requirements	Plan – Data gathering and integration, assessment method
	192.931	Confirmatory Direct Assessment (CDA) requirements	Plans – External corrosion and internal corrosion, schedule
	192.933	Actions to address integrity issues	Evaluation, demonstrate, notification, schedule, records, monitoring
	192.935	Additional preventative and mitigative measures	Measures (see numerous P&M measures in §192.935)
	192.937	Continual process of evaluation and assessment	Assessment, evaluation
	192.939	Required reassessment intervals	Establish intervals
	192.941	Low stress reassessment	Electrical survey, evaluation, leak survey, identification, analysis, tests, records integration
	192.945	Methods to measure program effectiveness	Program (4 performance measures in ASME B31.8S), reports, monitoring
192.947	Recordkeeping	Records	

Table Continued

Subpart	Section	Subject	Requirements
Gas Distribution Pipeline Integrity Management	P		
	192.1005	Implementing Subpart P	Program, written plan
	192.1007	Elements of integrity management plan	Written plan - 7 elements (see §192.1007), report
	192.1011	Recordkeeping	Records
	192.1015	Implementing Subpart P for a master meter or LPG operator	Program, written plan - 6 elements (see §192.1015), records

GUIDE MATERIAL APPENDIX G-192-22

(See guide material under §192.9)

GATHERING LINES REGULATORY REQUIREMENTS

Table provides a quick reference for applicable sections of code. Operators are encouraged to review guide material in the listed sections for additional information.

General Notes: *This table does not incorporate requirements for composite gathering lines; future guidance will be developed for those lines. Unless otherwise noted, this table does not incorporate specific plastic pipe requirements. "No" means not applicable as per §192.9; "Exempt" means specifically exempted in §192.9 as not required by code language.*

Code Requirement	Type A	Type B	Type C			Type R
			OD ≥ 8.625"	OD > 12.75"	OD > 16"	
PART 191						
191.1 – Scope	Yes	Yes	Yes	Yes	Yes	Yes
191.3 – Definitions	Yes	Yes	Yes	Yes	Yes	Yes
191.5 – Immediate Notice of Certain Incidents	Yes	Yes	Yes	Yes	Yes	Yes
191.7(a) & (d) – Report submission requirements	Yes	Yes	Yes	Yes	Yes	Yes
191.13 – Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines	Yes	Yes	Yes	Yes	Yes	Yes
191.15 – Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas storage facilities: Incident Report	Yes	Yes	Yes	Yes	Yes	Yes
191.17 – Transmission systems; gathering systems; liquefied natural gas facilities; and underground natural gas facilities: Annual Report	Yes	Yes	Yes	Yes	Yes	Yes
191.21 – OMB control number assigned to information collection	Yes	Yes	Yes	Yes	Yes	Yes
191.22(a) & (d) – National Registry of Pipeline and LNG Operators	Yes	Yes	Yes	Yes	Yes	Yes
191.22(c) – National Registry of Pipeline and LNG Operators	Yes	Yes	Yes	Yes	Yes	Yes
191.23 – Reporting Safety-Related Conditions	Yes	Yes	No	Yes ⁽³⁾	Yes	No
191.25 – Filing Safety-Related Conditions Reports	Yes	Yes	No	Yes ⁽³⁾	Yes	No
191.29 – National Pipeline Mapping System	No	No	No	No	No	No
PART 192						
192.3 – Definitions	Yes	Yes	Yes	Yes	Yes	Yes
192.5 – Class Locations	Yes	Yes	Yes	Yes	Yes	No
192.18 - How to notify PHMSA	Yes	Yes	Yes	Yes	Yes	No
Subpart B – Materials	Yes	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	No
192.67 - Records: Material properties	Yes	Exempt	Exempt	Exempt	Exempt	No
Subpart C – Pipe Design	Yes	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	No
192.127 - Records: Pipe design	Yes	Exempt	Exempt	Exempt	Exempt	No
Subpart D – Pipeline Components	Yes	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	No
192.150 – Passage of internal inspection devices	Exempt	Exempt	Exempt	Exempt	Exempt	No

Addendum 1, June 2022
Addendum 4, May 2024

192.205 - Records: Pipeline components	Yes	Exempt	Exempt	Exempt	Exempt	No
Subpart E – Welding	Yes	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	No
192.227(c) – Qualification of Welders	Yes	Exempt	Exempt	Exempt	Exempt	No
Subpart F – Joining	Yes	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	No
192.285(e) – Plastic Pipe: Qualifying persons to make joints	Exempt	Exempt	Exempt	Exempt	Exempt	No
Subpart G – Construction	Yes	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	No
Subpart I - Corrosion Control	Yes	Yes	Yes ⁽³⁾	Yes ⁽³⁾	Yes	No
192.493 - In-line inspection of pipelines	Exempt	Exempt	Exempt	Exempt	Exempt	No
Subpart J – Testing	Yes	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	Yes ⁽¹⁾	No
192.506 - Transmission lines: Spike hydrostatic pressure test	Exempt	Exempt	Exempt	Exempt	Exempt	No
Subpart L - Operations						
192.603 – Records	Yes	No	No	No	No	No
192.605 – Procedural manual for operations, maintenance, and emergencies	Yes	No	No	No	No	No
192.607 - Verification of Pipeline Material Properties and Attributes: Onshore steel transmission pipelines	Exempt	No	No	No	No	No
192.609 – Change in class location: Required study	Yes	No	No	No	No	No
192.611 – Change in Class Location: Confirmation or revision of maximum allowable operating pressure	Yes	No	No	No	No	No
192.613 – Continuing Surveillance	Yes	No	No	No	No	No
192.614 – Damage Prevention Program	Yes	Yes	Yes	Yes	Yes	No
192.615 – Emergency Plans	Yes	No	Yes	Yes	Yes	No
192.616 – Public Awareness	Yes	Yes	Yes ⁽³⁾	Yes ⁽³⁾	Yes	No
192.617 – Investigation of Failures	Yes	No	No	No	No	No
192.619(a) – MAOP establishment	Yes	Yes	No	Yes ⁽³⁾	Yes	No
192.619(c) – MAOP restriction exemption	Yes	Yes	No	Yes ⁽³⁾	Yes	No
192.619(e) – MAOP in accordance with §192.624	Exempt	Exempt	Exempt	Exempt	Exempt	No
192.624 - Maximum allowable operating pressure reconfirmation: Onshore steel transmission pipelines	Exempt	No	No	No	No	No
192.625 – Odorization of gas	Yes	No	No	No	No	No
192.627 – Tapping pipelines under pressure	Yes	No	No	No	No	No
192.629 – Purging of pipelines	Yes	No	No	No	No	No
192.631 – Control room management	Yes	No	No	No	No	No
192.632 - Engineering Critical Assessment for Maximum Allowable Operating Pressure Reconfirmation: Onshore steel transmission pipelines-	Exempt	No	No	No	No	No
Subpart M – Maintenance						
192.703(c) – General (Hazardous leaks)	Yes	Yes	Yes ⁽³⁾	Yes ⁽³⁾	Yes	No
192.705 – Transmission lines: Patrolling	Yes	No	No	No	No	No
192.706 – Transmission lines: Leakage Surveys	Yes	Yes	Yes ⁽³⁾	Yes ⁽³⁾	Yes	No
192.707 – Line markers for mains and transmission lines	Yes	Yes	Yes ⁽³⁾	Yes ⁽³⁾	Yes	No
192.709 – Transmission lines: Record keeping	Yes	No	No	No	No	No

192.710 - Transmission lines: Assessments outside of high consequence areas	Exempt	No	No	No	No	No
192.712 - Analysis of predicted failure pressure	Exempt	No	No	No	No	No
192.727 – Abandonment or deactivation of facilities	Yes	No	No	No	No	No
192.731 – Compressor stations: Inspection and testing of relief devices	Yes	No	No	No	No	No
192.736 – Compressor stations: Gas detection	Yes	No	No	No	No	No
192.739 – Pressure limiting and regulating stations: Inspection and testing ⁽²⁾	Yes	No	No	No	No	No
192.743 – Pressure limiting and regulating stations: Capacity of relief devices ⁽²⁾	Yes	No	No	No	No	No
192.745 – Valve maintenance: Transmission lines ⁽²⁾	Yes	No	No	No	No	No
192.749 – Vault maintenance	Yes	No	No	No	No	No
192.750 - Launcher and receiver safety	Yes	No	No	No	No	No
192.751 – Prevention of accidental ignition	Yes	No	No	No	No	No
Subpart N – Qualification of Pipeline Personnel	Yes ⁽⁴⁾	No	No	No	No	No
Subpart O – Gas Transmission Pipeline Integrity Management	Exempt	No	No	No	No	No
Part 199 – Drug and Alcohol Testing	Yes	Yes	Yes	Yes	Yes	No
Notes:						
1. Type B or Type C gathering lines that are new, replaced, relocated or otherwise changed must comply						
2. Regulated device may be located outside of actual regulated pipeline segment. Type B or Type C gathering lines with MAOP established per §192.619(a) might be required to have pressure regulating devices.						
3. Type C lines with an OD ≤16” that meet either Method 1 or Method 2 in §192.9(f)(1) are excepted from the requirement.						
4. Required for Class 3 and 4 locations. Class 2 locations require a description of the program.						

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Note: *GMA* means Guide Material Appendix; otherwise, *Appendix* means Appendix to Part 192.

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