February 19, 2019

Dear Guide Purchaser,


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
The changes in this addendum are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, or a block symbol (▌) where needed. The Federal Regulations were updated Amendment 192-124) that affected 28 sections of the Regulations. 6 GPTC transactions affected 13 sections of the Guide.

Editorial updates include application of the Editorial Guidelines, adjustments to page numbering, and adjustment of text on pages. While only significant editorial updates are marked, all affected pages carry the current addendum footnote. Editorial updates as indicated "EU" affected 9 sections of the Guide (plus other sections impacted by page adjustments, etc.).

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

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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.

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.


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.ag.org/gptc or paper copies may be purchased at https://www.ag.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.
GAS PIPING TECHNOLOGY COMMITTEE MEMBERSHIP

Listed by Committee

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Southern Company Gas

Lee Reynolds, 1st Vice Chair
NiSource Gas Distribution

Philip Sher, 2nd Vice Chair
Philip Sher Pipeline Consultant

Mike Bellman, Secretary
American Gas Association

Main Body (Consensus)

Purpose is to act as the final decision making body within the GPTC structure.
(Voting unless otherwise noted)

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Lee Reynolds, NiSource Gas Distribution, 1st Vice Chair
Philip Sher, Philip Sher Pipeline Consultant, 2nd Vice Chair
Mike Bellman, American Gas Association, Secretary
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DeWitt Burdeaux, TRC Solutions
John Butler, Equitrans Midstream
Willard Carey, Energy Experts International
John Chin, TransCanada Corporation
Allison Crabtree, DuraLine
Rodney Dyck, U.S. Department of Transportation – PHMSA
Mary Friend, Public Service Commission of West Virginia
Deanne Hughes, McElroy Mfr
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Randy Knapp, Plastics Pipe Institute
John Kottwitz, Missouri Public Service Commission
Douglas Lee, Consultant
George Lomax, Heath Consultants Incorporated

John Lueders, Retired
James McKenzie, Atmos Energy Corporation
Theron McLaren, U.S. Department of Transportation - PHMSA
Lane Miller, TRC Solutions
Robert Naper, Energy Experts International
Paul Oleksa, Oleksa and Associates, Inc.
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Jerome Themig, Retired
Erich Trombley, Southwest Gas Corporation
Alfredo Ulanday, EN Engineering
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Frank Volgstadt, Volgstadt & Associates

Executive Section

Responsible for the expedient and efficient handling of the business of the GPTC in all routine and ongoing matters.

Lee Reynolds, NiSource Gas Distribution, Chair
Mike Bellman, American Gas Association, Secretary
David Bull, ViaData LP
John Kottwitz, Missouri Public Service Commission
John Lueders, Retired
Jamie McKenzie, Atmos Energy Corp.
Joseph Opert, BGE, An Exelon Company
Eugene Palermo, Palermo Plastics Pipe Consulting

Kenneth Peters, Kinder Morgan Inc.
Leticia Quezada, Southern Company Gas
Alice Ratcliffe, Crestwood Midstream
Philip Sher, Philip Sher Pipeline Consultant
Richard Slagle, Southern Company Gas
Jerome Themig, Retired
Ram Veerapaneni, Retired

1 Membership as of 12/31/18
2 Non voting
Editorial Section
Responsible for maintaining consistent format and high structural standards for Guide Material and in ANSI Technical Reports.

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Lane Miller, TRC Solutions, Secretary
Stephen Bateman, E2 Consulting Engineers, Inc.
John Butler, Equitrans Midstream
Steven Gauthier, Energy Experts International

John Groot, Southern California Gas Company
Christine Maynard, NiSource, Inc.
Paul Oleksa, Oleksa and Associates, Inc.
Ram Veerapaneni, Retired

Liaison Section
Responsible for presenting GPTC actions to the appropriate government bodies and other groups in an effective manner.

Joseph Opert, BGE, An Exelon Company, Chair

Mary Ratcliffe, Crestwood Midstream, Chair
Frank Bennett, UGI Utilities, Inc.
David Bulley, ViaData LP
Allan Clarke, Consultant
Leo Cody, Liberty Utilities

Gregory Goble, R.W. Lyall & Company, Inc.
James McKenzie, Atmos Energy Corporation
Robert Naper, Energy Experts International
Eugene Palermo, Palermo Plastics Pipe Consulting

Regulations Section
Responsible for developing GPTC responses to Notices of Proposed Rulemaking (NPRMs) and to other regulatory Notices.

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Frank Bennett, UGI Utilities, Inc.
David Bulley, ViaData LP
Allan Clarke, Consultant
Leo Cody, Liberty Utilities

Gregory Goble, R.W. Lyall & Company, Inc.
James McKenzie, Atmos Energy Corporation
Robert Naper, Energy Experts International
Eugene Palermo, Palermo Plastics Pipe Consulting

Distribution Division
Responsible for technical review of all materials and take appropriate action before the material goes to the Main Body.

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Lane Miller, TRC Solutions, Secretary
Glen Armstrong, EN Engineering
Randy Bareither, Avista Utilities
Stephen Bateman, E2 Consulting Engineers, Inc.
Andrew Benedict, Opvantek Inc.
Michelle Blanchard, Alliant Energy
David Bulley, ViaData LP
Willard Carey, Energy Experts International
Leo Cody, Liberty Utilities
Mark Conners, UGI Utilities, Inc.
Denise Dolezal, Metropolitan Utilities District
Kalu Kelly Emeaba, GEIS Innovations
John Erickson, American Public Gas Association
Chris Foley, RCP Inc.
Mark Forster, Southern California Gas
Lloyd Freeman, Southern California Gas
Anthony Fuhrman, Public Service Electric & Gas
Jamie Garland, Maine Natural Gas
John Goetz, Meade
Steven Groot, Gas Operations Consultant
John Groot, Retired
Matt Hill, Vectren
John Kottwitz, Missouri Public Service Commission

Brent Koyum, CenterPoint Energy
Joel Martell, Southwest Gas
Christine Maynard, NiSource, Inc.
James McKenzie, Atmos Energy Corporation
Theron McLaren, U.S. Department of Transportation - PHMSA
Rich Medcalf, Indiana Utility Regulatory Commission
Robert Naper, Energy Experts International
Paul Oleksa, Oleksa and Associates, Inc.
Joseph Opert, BGE, An Exelon Company
Christopher Pioli, Jacobs Consultancy
Michael Purcell, Public Utilities Commission of Ohio
Charles Rayot, Ameren Illinois
Patrick Seamands, Retired
Parashar Sheth, National Grid
Ronda Shupert, Pacific Gas & Electric Company
Walter Siedlecki, AEGIS Insurance Services, Inc.
Richard Slagle, Southern Company Gas
David Spangler, NPL
Jerome Themig, Retired
Ryan Truair, NW Natural
Alfredo Ulanday, EN Engineering
Jacob Waller, Washington Gas Light Company
Thomas Webb, Peoples Gas Light & Coke
Randy Wilson, Spire
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Responsible for technical review of all materials and take appropriate action before the material goes to the Main Body.

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Frank Volgstadt, Volgstad & Associates, Secretary
Christopher Ampfer, WL Plastics Corp.
DeWitt Burdeaux, TRC Solutions
Allison Crabtree, DuraLine
Steven Gauthier, Energy Experts International
Gregory Goble, R.W. Lyall & Company, Inc.
Alan Goodman, HammerHead Trenchless
Deanne Hughes, McElroy Manufacturing, Inc.
Richard Huriaux, Consulting Engineer
James Johnston Jr., McElroy Manufacturing, Inc.
Randy Knapp, Plastics Pipe Institute
George Lomax, Heath Consultants Incorporated
William Luff, JANA Corp.
Mary Lee McDonald, Performance Pipe
Daniel O’Leary, Timberline Tool
Robert Schmidt, Canad Oil Forge
David Wartluft, Continental Industries

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Responsible for technical review of all materials and take appropriate action before the material goes to the Main Body.

Kenneth Peters, Kinder Morgan Inc., Chair
John Butler, Equitrans Midstream, Secretary
Erik Anderson, Northwestern Energy
Stephen Beatty, LG&E-KU, PPL Companies
Frank Bennett, UGI Utilities, Inc.
John Chin, TransCanada Corporation
Allan Clarke, Consultant
Rodney Dyck, U.S. Department of Transportation – PHMSA
Michael Falk, Xcel Energy
Robert Fassett, E2 Consulting Engineers
Mary Friend, Public Service Commission of West Virginia
George Hamaty, TransCanada / Columbia Pipeline Group
Renee Hermiller, Marathon Petroleum Corporation
Joni Johnson, Cook Inlet Consulting
Douglas Lee, Consultant
Ray Lewis, Retired
Thomas Marlow, PRCI
Erin McKay, Hilcorp Alaska, LLC
Jason Pionk, Consumers Energy
Alice Ratcliffe, Crestwood Midstream
Timothy Strommen, WE Energies
David Terzian, National Grid
Erich Trombley, Southwest Gas Corporation
Ram Veerapaneni, Retired
Jim Walton, Mears Group Inc.
Brian Wolf, Hatch Mott MacDonald
Anson Wong, Southern California Gas Company

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Responsible for developing Guide Material, ANSI Technical Reports, and other technical material as directed by the Main Body.

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Michael Falk, Excel Energy
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Lloyd Freeman, Southern California Gas
Mary Friend, Public Service Commission of West Virginia
Jamie Garland, Maine Natural Gas
Alison Crabtree, DuraLine
Steven Groeber, Gas Operations Consultant
George Hamaty, TransCanada / Columbia Pipeline Group
Renee Hermiller, Marathon Petroleum Corporation
Matt Hill, Vectren
Joni Johnson, Cook Inlet Consulting
John Kottwitz, Missouri Public Service Commission
George Lomax, Heath Consultants Incorporated
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Christopher Pioli, Jacobs Consultancy
Jason Pionk, Consumers Energy
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Patrick Seamands, Retired
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David Spangler, NPL
Timothy Strommen, WE Energies
Jerome Themig, Retired
Ryan Truair, NW Natural
Alfredo Ulanday, EN Engineering
Ram Veerapaneni, Retired
Jacob Waller, Washington Gas Light Company
Jim Walton, Mears Group Inc.
David Wartluft, Continental Industries
Randy Wilson, Spire
Brian Wolf, Hatch Mott MacDonald
Anson Wong, Southern California Gas Company
Design Task Group

Responsible for developing Guide Material, ANSI Technical Reports, and other technical material as directed by the Main Body.

James McKenzie, Atmos Energy Corporation, Chair
Douglas Lee, Consultant, Secretary
Christopher Ampfer, WL Plastics Corp.
Erik Anderson, Northwestern Energy
Stephen Beatty, LG&E-KU, PPL Companies
Andrew Benedict, Ovantek
Michelle Blanchard, Alliant Energy
DeWitt Burdeaux, TRC Solutions
John Butler, Equitran Midstream
John Chin, TransCanada Corporation
Allan Clarke, Consultant
Mark Connors, UGI Utilities, Inc.
Allison Crabtree, DuraLine
Denise Dolezal, Metropolitan Utilities District
Rodney Dyck, U.S. Department of Transportation - PHMSA
Robert Fassett, E2 Consulting Engineers
Chris Foley, RCP Inc.
Anthony Fuhrman, Public Service Electric & Gas
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John Groot, Retired
Deanne Hughes, McElroy Manufacturing, Inc.
Richard Huriaux, Consulting Engineer
Randy Knapp, Plastics Pipe Institute
Brent Koym, CenterPoint Energy
John Lueders, Retired
William Luff, JANA Corp.
Thomas Marlow, PRCI
Theron McLaren, U.S. Department of Transportation - PHMSA
Paul Oleksa, Oleksa and Associates, Inc.
Eugene Palermo, Palermo Plastics Pipe Consulting
Kenneth Peters, Kinder Morgan Inc.
Mike Purcell, PUC of Ohio
Robert Schmidt, Canadai Forge
Parashar Sheth, National Grid
David Terzian, National Grid
Erich Trombley, Southwest Gas Corporation
Frank Volgstadt, Volgstadt & Associates

Integrity Management / Corrosion Task Group

Responsible for developing Guide Material, ANSI Technical Reports, and other technical material as directed by the Main Body.

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James McKenzie, Atmos Energy Corporation, Secretary
Glen Armstrong, EN Engineering
Frank Bennett, UGI Utilities, Inc.
John Chin, TransCanada Corporation
Allan Clarke, Consultant
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Robert Fassett, E2 Consulting Engineers
Anthony Fuhrman, Public Service Electric & Gas
Brent Koym, CenterPoint Energy
Thomas Marlow, Vectren Corporation
Theron McLaren, U.S. Department of Transportation - PHMSA
Lane Miller, TRC Solutions
Daniel O'Leary, Timberline Tool
Paul Oleksa, Oleksa and Associates, Inc.
Christopher Pioli, Jacobs Consultancy
Timothy Strommen, WE Energies
Erich Trombley, Southwest Gas Corporation
Ryan Truair, NW Natural
Jim Walton, Mears Group Inc.
David Wartluft, Continental Industries
Randy Wilson, Spire
Brian Wolf, Hatch Mott MacDonald
Anson Wong, Southern California Gas Company
Operations & Maintenance / Operator Qualification Task Group

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Douglas Lee, KLJ Progress Solutions, Secretary
Erik Anderson, Northwestern Energy
Randy Bareither, Avista Utilities
Stephen Bateman, E2 Consulting Engineers, Inc.
Stephen Beatty, LG&E-KU, PPL Companies
Andrew Benedickt, Opvanteck Inc.
Michelle Blanchard, Alliant Energy
David Bull, ViaData LP
John Butler, Equitrans Midstream
Willard Carey, Energy Experts International
Leo Cody, Liberty Utilities
Mark Connors, UGI Utilities, Inc.
Denise Dolezal, Metropolitan Utilities District
John Erickson, American Public Gas Association
Michael Falk, Xcel Energy
Chris Foley, RCP Inc.
Mark Forster, Southern California Gas
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John Goetz, Meade
Alan Goodman, HammerHead Trenchless
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George Hamaty, TransCanada / Columbia Pipeline Group
Renee Hermiller, Marathon Petroleum Corporation
Matt Hill, Vectren
Joni Johnson, Cook Inlet Consulting
James Johnston, McElroy Manufacturing, Inc.
John Kottwitz, Missouri Public Service Commission
George Lomax, Heath Consultants Incorporated
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Christine Maynard, NiSource, Inc.
Erin McKay, Hilcorp Alaska, LLC
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Jason Ponk, Consumers Energy
Michael Purcell, Public Utilities Commission of Ohio
Alice Ratcliffe, Crestwood Midstream
Charles Rayot, Ameren Illinois
Ronda Shupert, Pacific Gas & Electric Company
Walter Siedlecki, AEGIS Insurance Services, Inc.
David Spangler, NPR
Alfredo Ulanday, EN Engineering
Jacob Waller, Washington Gas Light Company
Thomas Webb, Peoples Gas Light & Coke

Plastic Task Group

Responsible for developing Guide Material, ANSI Technical Reports, and other technical material as directed by the Main Body.

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Frank Volgstadt, Volgstadt & Associates, Secretary
Christopher Ampfer, WL Plastics Corp.
Glen Armstrong, UGI Engineering
DeWitt Burdeaux, TRC Solutions
Allison Crabtree, DuraLine
Gregory Goble, R.W. Lyall & Company, Inc.
Deanne Hughes, McElroy Manufacturing, Inc.
Richard Huriaux, Consulting Engineer
John Groot, Retired
James Johnston, Jr., McElroy Manufacturing, Inc.
Randy Knapp, Plastics Pipe Institute
William Luff, JANA Corp.
Joel Martell, Southwest Gas
Mary Lee McDonald, Performance Pipe
Lane Miller, TRC Solutions
Eugene Palermo, Palermo Plastics Pipe Consulting
Patrick Seamands, Retired
Parashar Sheth, National Grid

Committee Scope

The Gas Piping Technology Committee (GPTC) is an independent technical group of individuals with expertise in, and concern for, natural gas pipeline safety and is responsible for:

- Developing and maintaining ANSI Technical Reports regarding the application of natural gas pipeline technology and operating or maintenance practices.
- Promoting the use of voluntary consensus standards.
• Petitioning the United States Department of Transportation (DOT) for changes in Federal Natural Gas Pipeline Safety Regulations based on the technical expertise of the GPTC.
• When deemed appropriate by the Main Body, commenting on Advanced Notice of Proposed Rulemakings, Notice of Proposed Rulemakings, Final Rules, and other regulatory notices issued by DOT involving such regulations.
• Reviewing applicable National Transportation Safety Board (NTSB) reports, DOT and State Pipeline Safety Agency incident reports, and taking appropriate action including that of responding to recommendations issued to the GPTC.
• Taking such actions that are necessary and proper to further the safe application of natural gas pipeline technology.
# GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation

<table>
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Damage Prevention - Emergency Response: DP/ER  
Operations and Maintenance - Operator Qualification: O&M/OQ

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### Abbreviations:
- Chairperson: Chair
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- Damage Prevention - Emergency Response: DP/ER
- Operations and Maintenance - Operator Qualification: O&M/OQ

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<th>Name</th>
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### GAS PIPE TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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**Abbreviations:**
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## GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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LETTER TO GAS PIPING TECHNOLOGY COMMITTEE FROM THE U.S. DEPARTMENT OF TRANSPORTATION

May 29, 2018

Ms. Leticia Quezada
Chair, Gas Piping Technology Committee
Nicor Gas
1844 Ferry Road
Naperville, IL 60563-9662

Dear Ms. Quezada:

The U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) appreciates the cooperative effort needed to develop the Guide for Gas Transmission, Distribution, and Gathering Piping Systems (Guide). The Guide, advisory in nature, provides clear and concise guidance to gas piping systems operators on complying with the Federal pipeline safety standards. PHMSA recognizes the efforts of the Gas Piping Technology Committee (GPTC) to enhance the pipeline safety practices of those who use the Guide.

PHMSA looks forward to the continued and coordinated efforts by the GPTC members toward improvements in pipeline safety practices through the use of the Guide.

Sincerely,

[Signature]

Alan K. Mayberry
Associate Administrator for Pipeline Safety
December 4, 2018

Ms. Leticia Quezada
Chair, Gas Piping Technology Committee
Nicor Gas
1844 Ferry Road
Naperville, IL 60563-9662

Dear Ms. Quezada:

The National Association of Pipeline Safety Representatives (NAPSR) is comprised of the State Pipeline Safety Program Managers in the continental 48 states, the District of Columbia, Puerto Rico and it also includes two Hazardous Liquid programs under certification by PHMSA. NAPSR appreciates the cooperative effort needed to develop the Guide for Gas Transmission, Distribution, and Gathering Piping Systems (GPTC Guide). The GPTC Guide, which is advisory in nature, provides additional, comprehensive guidance to gas piping systems operators on complying with the Federal pipeline safety standards. NAPSR recognizes the efforts of the Gas Piping Technology Committee (GPTC) to enhance the pipeline safety practices of those who use the Guide.

NAPSR looks forward to the continued collaborative efforts by the GPTC members toward improvements in pipeline safety practices through the ongoing development, improvement, and use of the GPTC Guide.

Sincerely,

Gary A. Kenny
National Chair
National Association of Pipeline Safety Representatives
gary.kenny@maine.gov
www.napsr.org

C: Robert Clarillos, NAPSR Administrative Manager
AMERICAN GAS ASSOCIATION (AGA)
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EDITORIAL CONVENTIONS OF THE GUIDE

Practices Used in the Guide

♦ If the guide material does not cover all the specific elements in a section of the Federal Regulations (Regulation(s)), and there is no editorial note, no other guide material has been deemed necessary by the Gas Piping Technology Committee (Committee).

♦ The term "includes" does not limit any list to those items presented and means, "includes but not limited to." This term is used in the same manner as it is used in the Regulations (reference §192.15). Further, added qualifiers such as "may" or "might" are sometimes used to emphasize that a list is not intended to set a minimum requirement or practice.

♦ The term "should" indicates recommendations that are not mandatory, but are to be acted upon as appropriate. As such, this guide material is advisory in nature, and operators may use it (or other equally acceptable methods) for a regulatory compliance aid.

♦ All figures and tables located in the basic guide material are designated by the corresponding Regulation section number followed by a capital letter for figures (sequentially), or lower case Roman numeral for tables (e.g., FIGURE 192.485A or TABLE 192.485i).

♦ The date shown in the title block for each section is the effective date of the original Regulation or its latest amendment.

♦ Sections of the Regulations that have been deleted are not listed by title in the Contents unless reserved by the Regulations. However, the section numbers have been retained in the Guide, along with their effective date of removal (e.g., §192.57, Removed and reserved. [Effective 03/08/89]).

♦ Sections of the Regulations having a future effective date may be presented for both the current and new requirements and with the effective date emphasized. In such case, the guide material is subject to review in light of the new requirements.

Common Notes in the Guide

♦ No guide material necessary. In the opinion of the Committee, the Regulation section is self-explanatory and no additional information is provided.

♦ No guide material available at present. The Committee has not issued guide material or has not yet determined if guide material is necessary.

♦ This guide material is under review following Amendment (either 19x-yy or control number). The Committee is currently reviewing the amendment.

♦ Discontinued or Withdrawn. Where either of these words accompanies a listing of an industry standard or other published reference, it indicates that the document is no longer current or has been withdrawn, and may not be available from its original source. The document may be available from an alternate source. When using such a document, care should be taken to determine the validity of the material and the reason for which it was discontinued or withdrawn.

♦ See §19x.xxx, refers to Regulation Section 19x.xxx and the guide material directly beneath it.
♦ See x of the guide material under §19y.yyy. This refers to Section x of the guide material directly beneath §19y.yyy.

♦ See x above (or below). This refers to Section x of the guide material in which the reference appears.
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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.

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.


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) 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.
(d) 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.
(e) For guidance on calculating gas loss from a damaged pipeline, see Guide Material Appendix G-191-5.
§191.5
Immediate notice of certain incidents.

(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.

(GUIDE MATERIAL

This guide material is under review following Amendment 191-25.

(a) Complete information is not necessary for the initial electronic or telephonic incident report to National Response Center (NRC). Refer to Guide Material Appendix G-191-1 for a sample worksheet that may be used to compile information for the incident report. The initial incident report should be made within 2 hours of discovery of the incident. Initial report 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 product 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, if known.
   (9) The responsible party, if known.
   (10) Weather conditions at the incident site.

(b) If an incident report has been made and further investigation reveals that the event was not an "incident," and therefore not reportable, the report should be nullified with a letter. This letter should be sent to the Information Resources Manager at the address specified in §191.7 within 30 days of the event. The letter
should reference the NRC incident report number issued when the initial notification was made and briefly explain why the incident report is being nullified. Incident reports cannot be removed from the database, but the letter may help ensure accurate PHMSA-OPS records.

(c) Operators should consider making an additional report if there is a significant change in the data previously provided to the NRC. A significant change may include an increase or decrease in the number of injuries or fatalities previously reported, or a revised estimate of property damage that is at least 10 times that previously reported. Consideration should be given to making an additional report up to 48 hours following the initial report. The operator should clearly report to the NRC that additional information is being provided and give the NRC the initial report’s assigned NRC Report Number. However, any report following the initial report will result in an additional NRC Report Number being created for the same event. All related NRC Report Numbers should be referenced in the PHMSA-OPS electronic or written incident report (see §§191.9 and 191.15).

(d) For intrastate pipelines, it is necessary to comply with federal reporting requirements even though an "incident" has been reported to the appropriate state agency.

§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.

§191.9
Distribution system: Incident report.

(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.


GUIDE MATERIAL

See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms. Additional state requirements may exist for intrastate facilities.

§191.11
Distribution system: Annual report.

(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 or to a petroleum gas system that serves fewer than 100 customers from a single source.


GUIDE MATERIAL

See Guide Material Appendix G-191-2 for an index of PHMSA reporting forms. Report forms and instructions can be downloaded from the PHMSA-OPS website at www.phmsa.dot.gov/forms/pipeline-forms. Additional state requirements may exist for intrastate facilities.
PART 192

MINIMUM FEDERAL SAFETY STANDARDS

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, 60116, 60118, 60137, and 60141; and 49 CFR 1.97.

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).


Addendum 2, February 2019 17
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 may benefit from information provided in the "Guidance Manual for Operators of LP Gas Systems" available at https://www.phmsa.dot.gov/training/pipeline/guidance-manuals.

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

2 STATE REQUIREMENTS


3 CONTRACTORS

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

4 OFFSHORE PIPELINES

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

5 HYDROGEN PIPELINES


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

7 SPECIAL PERMITS

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

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

§192.3
Definitions.

As used in this part:

Abandoned means permanently removed from service.

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

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

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

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

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

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

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

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

Exposed underwater pipeline means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from mean low water.

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

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

Gulf of Mexico and its inlets means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

Hazard to navigation means, for the purposes of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in waters less than 15 feet (4.6 meters) deep, as measured from the mean low water.

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

*Line section* means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

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

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

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

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

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

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

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

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

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

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

*Petroleum gas* means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

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

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

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

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

*Service line* means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer’s piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

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

*SMYS* means specified minimum yield strength is:

1. For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

2. For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with §192.107(b).

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

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

*Transmission line* means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

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

*Transportation of gas* means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

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

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

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

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

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

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**GUIDE MATERIAL**

This guide material is under review following Amendment 192-122.

**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.

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.
§192.7
What documents are incorporated by reference partly or wholly in this part? [Effective Date: 01/22/19]

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

1) Availability of standards incorporated by reference. All of the materials incorporated by reference are available for inspection from several sources, including the following:


(iii) Copies of standards incorporated by reference in this part can also be purchased or are otherwise made available from the respective standards-developing organization at the addresses provided in the centralized IBR section below.

2) [Reserved]

<table>
<thead>
<tr>
<th>IBR approved for:</th>
</tr>
</thead>
<tbody>
<tr>
<td>§§192.55(e); 192.112(a), (b), (d), (e); 192.113; and Item I, Appendix B to Part 192.</td>
</tr>
</tbody>
</table>


IBR approved for: (Continued)


<p>| (8) | ASME Boiler &amp; Pressure Vessel Code, Section VIII, Division 1 “Rules for Construction of Pressure Vessels,” 2007 edition, July 1, 2007, (ASME BPVC, Section VIII, Division 1). | §§192.153(a), (b), (d); and 192.165(b). |</p>
<table>
<thead>
<tr>
<th>IBR approved for: (Continued)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(12) ASTM D2517–00, “Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings,” (ASTM D 2517).</td>
</tr>
<tr>
<td>IBR approved for:</td>
</tr>
<tr>
<td>-----------------</td>
</tr>
<tr>
<td>(g) NACE International (NACE), 1440 South Creek Drive, Houston, TX 77084, phone: 281–228–6223 or 800–787–623, Web site: <a href="http://www.nace.org/Publications/">http://www.nace.org/Publications/</a>.</td>
</tr>
<tr>
<td>(1) ANSI/NACE SP0502–2010, Standard Practice, “Pipeline External Corrosion Direct Assessment Methodology,” revised June 24, 2010, (NACE SP0502).</td>
</tr>
<tr>
<td>(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)).</td>
</tr>
<tr>
<td>(2) [Reserved]</td>
</tr>
<tr>
<td>IBR approved for: (Continued)</td>
</tr>
<tr>
<td>--------------------------------</td>
</tr>
</tbody>
</table>


§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. |

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**GUIDE MATERIAL**

This guide material is under review following Amendments 192-119.

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

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

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§192.8
How are onshore gathering lines and regulated onshore gathering lines 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 furthermost downstream point in a production operation as defined in section 2.3 of API RP 80. This furthermost 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 furthermost downstream compressor used to increase gathering line pressure for delivery to another pipeline.

(b) For purposes of §192.9, “regulated onshore gathering line” means:

(1) Each onshore gathering line (or segment of onshore gathering line) with a feature described in the second column that lies in an area described in the third column; and

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

<table>
<thead>
<tr>
<th>Type</th>
<th>Feature</th>
<th>Area</th>
<th>Safety Buffer</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>— Metallic and the MAOP produces a hoop stress of 20 percent or more 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. — Non-metallic and the MAOP is more than 125 psig (862 kPa).</td>
<td>Class 2, 3, or 4 location (see §192.5).</td>
<td>None.</td>
</tr>
</tbody>
</table>

Table continued on next page
Gathering Lines – Type A or B

Gathering Line

Within inlet of the Gulf of Mexico

Yes

Offshore gathering lines must comply with the requirements of Type A lines

Onshore

Yes

Pipeline operated < 5 psig?

Class 1?

No

No

Metallic Line with MAOP ≥ 20% SMYS? Or Non-metallic Line with MAOP > 125 psig?

Yes

Type A Line

The entire Class 2, 3, or 4 location is a regulated Type A line.

No

Metallic Line with MAOP < 20% SMYS? Or Non-metallic Line with MAOP ≤ 125 psig?

Type B Line

Per table under §192.8(b)(2):
(a) Operators may choose to count the entire Class 2 location as a jurisdictional segment or apply the following criteria to determine jurisdiction.
(b) >10 but ≤40 dwellings within 150 ft in a continuous sliding mile?
(c) 5 or more dwellings within 150 ft of a continuous sliding 1000 ft?

Operator chooses (a)?

No

Does (b) or (c) apply?

No

The entire Class 2 location is regulated.

Yes

Apply 150 ft safety buffer to the ends of each area and clusters to define the limits of each regulated segment.

Type A Lines

Must comply with the requirements applicable to transmission lines, except the requirements in §192.150 and Subpart O. In addition, operators of Type A regulated offshore gathering lines in Class 2 locations may demonstrate compliance with Subpart N by describing the processes used to determine the qualification of persons performing operations and maintenance tasks.

Type B Lines

Must comply with Subpart I and §§192.814, 192.816, 192.818, 192.701.

FIGURE 192.8C
§192.9  
What requirements apply to gathering lines?  
[Effective Date: 1/22/19]

(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 §192.150 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 §192.150 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 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;
2. If the pipeline is metallic, control corrosion according to requirements of subpart I of this part applicable to transmission lines;
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;
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) **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 regulated onshore gathering line 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 line listed in the first column, unless the Administrator finds a later deadline is justified in a particular case:

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Compliance deadline</th>
</tr>
</thead>
<tbody>
<tr>
<td>Control corrosion according to Subpart I requirements for transmission lines.</td>
<td>April 15, 2009</td>
</tr>
<tr>
<td>Carry out a damage prevention program under §192.614.</td>
<td>October 15, 2007</td>
</tr>
<tr>
<td>Requirement</td>
<td>Compliance deadline</td>
</tr>
<tr>
<td>----------------------------------------------------------------------------</td>
<td>---------------------</td>
</tr>
<tr>
<td>Establish MAOP under §192.619.</td>
<td>October 15, 2007</td>
</tr>
<tr>
<td>Install and maintain line markers under §192.707.</td>
<td>April 15, 2008</td>
</tr>
<tr>
<td>Establish a public education program under §192.616</td>
<td>April 15, 2008</td>
</tr>
<tr>
<td>Other provisions of this part as required by paragraph (c) of this section for Type A lines.</td>
<td>April 15, 2009</td>
</tr>
</tbody>
</table>

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


GUIDE MATERIAL
See §192.1 for gathering lines excluded from the provisions of Part 192. Also, see the "Glossary of Commonly Used Terms" under §192.3 for definition of "otherwise changed."

§192.10
Outer continental shelf pipelines.
[Effective Date: 03/08/05]

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

[Issued by Amtd. 192-81, 62 FR 61692, Nov. 19, 1997 with 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.

(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.

[Amendment dates...]

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

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

GUIDE MATERIAL

No guide material available at present.

§192.13
What general requirements apply to pipelines regulated under this part?

[Effective Date: 04/14/06]

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

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore gathering line.</td>
<td>July 31, 1977</td>
</tr>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until April 14, 2006.</td>
<td>March 15, 2007</td>
</tr>
<tr>
<td>All other pipelines.</td>
<td>March 12, 1971</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>Pipeline</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore gathering line.</td>
<td>July 31, 1977</td>
</tr>
<tr>
<td>Regulated onshore gathering line to which this part did not apply until April 14, 2006.</td>
<td>March 15, 2007</td>
</tr>
<tr>
<td>All other pipelines.</td>
<td>November 12, 1970</td>
</tr>
</tbody>
</table>

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


GUIDE MATERIAL

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

§192.14
Conversion to service subject to this part.

[Effective Date: 03/24/17]

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements:

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

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

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

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

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

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

[Issued by Amtd. 192-30, 42 FR 60146, Nov. 25, 1977; Amtd. 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) Tensile tests. See Appendix B to Part 192.
(e) Internal inspections.
(f) Radiographic inspections.
(g) Pressure tests. See §192.619(a)(1).

3 VISUAL INSPECTION OF UNDERGROUND SEGMENTS

Generally, the segments to be inspected should be at locations where the worst probable conditions may be expected. The following criteria should be used for the selection of inspection sites.
(a) Corrosion surveys (inadequately protected segments, poor coating, stray currents, and interference).
(b) Pipeline component locations.
(c) Locations subject to mechanical damage.
(d) Foreign pipeline crossings.
(e) Locations subject to damage due to chemicals, such as acid.
(f) Segments subject to coating deterioration due to soil stresses and internal or external temperature extremes.
(g) Population density.

§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.


GUIDE MATERIAL

No guide material necessary.

§192.17  
(Removed.)  
[Effective Date: 07/20/81]
§192.57
(Removed and reserved.)

[Effective Date: 03/08/89]

§192.59
Plastic pipe.

[Effective Date: 01/22/19]

(a) New plastic pipe is qualified for use under this part if —
   (1) It is manufactured in accordance with 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.


GUIDE MATERIAL

1 GENERAL

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 D2513-09a for polyethylene (PE), ASTM D2513-99 for other thermoplastics, 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.
2 WEATHERING STATEMENT FOR PLASTIC PIPE

(a) The resistance of plastic pipe to outdoor exposure can vary greatly. The manufacturer of the plastic pipe should be required to supply a written statement of the period of time the product can be stored outside without loss of properties that qualify it for buried gas piping application. ASTM pipe specifications include UV resistance requirements for outdoor storage stability. The operator should ensure that this exposure time is not exceeded. Examples: ASTM D2513-09a specifies that black PE pipe or black PE pipe with yellow stripes can be stored outdoors, unprotected from UV radiation, for up to 10 years and that yellow PE pipe can be stored outdoors for up to 3 years. 

Note: For aboveground installation, see (d) below.

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

§192.61
(Removed and reserved.)

§192.63
Marking of materials.

(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.
GUIDE MATERIAL

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

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

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

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

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

§192.65
Transportation of pipe.  
[Effective Date: 10/01/15]

(a) Railroad. In a pipeline to be operated at a hoop stress of 20 percent or more of SMYS, an operator may not install pipe having an outer diameter to wall thickness 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).

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

GUIDE MATERIAL

This guide material is under review following Amendment 192-120.

No guide material necessary

§192.67

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.

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

<table>
<thead>
<tr>
<th>Gas temperature in degrees Fahrenheit (Celsius)</th>
<th>Temperature derating factor (T)</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 °F (121 °C) or less</td>
<td>1.000</td>
</tr>
<tr>
<td>300 °F (149 °C)</td>
<td>0.967</td>
</tr>
<tr>
<td>350 °F (177 °C)</td>
<td>0.933</td>
</tr>
<tr>
<td>400 °F (204 °C)</td>
<td>0.900</td>
</tr>
<tr>
<td>450 °F (232 °C)</td>
<td>0.867</td>
</tr>
</tbody>
</table>

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.

(a) Design formula. Design formulas for plastic pipe are determined in accordance with either of the following formulas:

\[
P = \frac{2S \cdot t \cdot (DF)}{(D-t)}
\]

\[
P = \frac{2S \cdot (DF)}{(SDR-1)}
\]

- \(P\) = 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 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 12 inches or less; and
(iv) The wall thickness for a given outside diameter is not less than that listed in the following table:

<table>
<thead>
<tr>
<th>Pipe size (inches)</th>
<th>Minimum wall thickness (inches)</th>
<th>Corresponding SDR (values)</th>
</tr>
</thead>
<tbody>
<tr>
<td>½&quot; CTS............</td>
<td>0.090</td>
<td>7</td>
</tr>
<tr>
<td>¾&quot; CTS............</td>
<td>0.090</td>
<td>9.7</td>
</tr>
<tr>
<td>½&quot; IPS.............</td>
<td>0.090</td>
<td>9.3</td>
</tr>
<tr>
<td>¾&quot; IPS.............</td>
<td>0.095</td>
<td>11</td>
</tr>
<tr>
<td>1&quot; CTS............</td>
<td>0.119</td>
<td>11</td>
</tr>
<tr>
<td>1&quot; IPS.............</td>
<td>0.119</td>
<td>11</td>
</tr>
<tr>
<td>1 ¼&quot; IPS..........</td>
<td>0.151</td>
<td>11</td>
</tr>
<tr>
<td>1 ½&quot; IPS..........</td>
<td>0.173</td>
<td>11</td>
</tr>
<tr>
<td>2&quot; .........</td>
<td>0.216</td>
<td>11</td>
</tr>
<tr>
<td>3&quot; ...............</td>
<td>0.259</td>
<td>13.5</td>
</tr>
<tr>
<td>4&quot; ...............</td>
<td>0.265</td>
<td>17</td>
</tr>
<tr>
<td>6&quot; ...............</td>
<td>0.315</td>
<td>21</td>
</tr>
<tr>
<td>8&quot; ...............</td>
<td>0.411</td>
<td>21</td>
</tr>
<tr>
<td>10&quot; .............</td>
<td>0.512</td>
<td>21</td>
</tr>
<tr>
<td>12&quot; .............</td>
<td>0.607</td>
<td>21</td>
</tr>
</tbody>
</table>

(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 the following table:
(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 the following table.

<table>
<thead>
<tr>
<th>Pipe size</th>
<th>Minimum wall thickness (inches)</th>
<th>Corresponding SDR (values)</th>
</tr>
</thead>
<tbody>
<tr>
<td>½” CTS……….</td>
<td>0.090</td>
<td>7</td>
</tr>
<tr>
<td>¾” CTS……….</td>
<td>0.090</td>
<td>9.7</td>
</tr>
<tr>
<td>½” IPS……….</td>
<td>0.090</td>
<td>9.3</td>
</tr>
<tr>
<td>¾” IPS……….</td>
<td>0.095</td>
<td>11</td>
</tr>
<tr>
<td>1” CTS……….</td>
<td>0.119</td>
<td>11</td>
</tr>
<tr>
<td>1” IPS……….</td>
<td>0.119</td>
<td>11</td>
</tr>
<tr>
<td>1 ¼” IPS………</td>
<td>0.151</td>
<td>11</td>
</tr>
<tr>
<td>1 ½” IPS………</td>
<td>0.173</td>
<td>11</td>
</tr>
<tr>
<td>2”</td>
<td>0.216</td>
<td>11</td>
</tr>
<tr>
<td>3”</td>
<td>0.259</td>
<td>13.5</td>
</tr>
<tr>
<td>4”</td>
<td>0.333</td>
<td>13.5</td>
</tr>
<tr>
<td>6”</td>
<td>0.491</td>
<td>13.5</td>
</tr>
</tbody>
</table>

(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:

<table>
<thead>
<tr>
<th>Pipe size</th>
<th>Minimum wall thickness (inches)</th>
<th>Corresponding SDR (values)</th>
</tr>
</thead>
<tbody>
<tr>
<td>½” CTS……….</td>
<td>0.090</td>
<td>7</td>
</tr>
<tr>
<td>¾” CTS……….</td>
<td>0.090</td>
<td>9.7</td>
</tr>
<tr>
<td>½” IPS……….</td>
<td>0.090</td>
<td>9.3</td>
</tr>
<tr>
<td>¾” IPS……….</td>
<td>0.095</td>
<td>11</td>
</tr>
<tr>
<td>1” CTS……….</td>
<td>0.119</td>
<td>11</td>
</tr>
<tr>
<td>1” IPS……….</td>
<td>0.119</td>
<td>11</td>
</tr>
<tr>
<td>1 ¼” IPS………</td>
<td>0.151</td>
<td>11</td>
</tr>
<tr>
<td>1 ½” IPS………</td>
<td>0.173</td>
<td>11</td>
</tr>
<tr>
<td>2”</td>
<td>0.216</td>
<td>11</td>
</tr>
<tr>
<td>3”</td>
<td>0.259</td>
<td>13.5</td>
</tr>
<tr>
<td>4”</td>
<td>0.333</td>
<td>13.5</td>
</tr>
<tr>
<td>6”</td>
<td>0.491</td>
<td>13.5</td>
</tr>
<tr>
<td>Nominal size in inches (millimeters)</td>
<td>Minimum wall thickness in inches (millimeters)</td>
<td></td>
</tr>
<tr>
<td>-------------------------------------</td>
<td>---------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>2 (51)</td>
<td>0.060 (1.52)</td>
<td></td>
</tr>
<tr>
<td>3 (76)</td>
<td>0.060 (1.52)</td>
<td></td>
</tr>
<tr>
<td>4 (102)</td>
<td>0.070 (1.78)</td>
<td></td>
</tr>
<tr>
<td>6 (152)</td>
<td>0.100 (2.54)</td>
<td></td>
</tr>
</tbody>
</table>


GUIDE MATERIAL

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) 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) 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.
### Table 192.121i

<table>
<thead>
<tr>
<th>Pipe Material</th>
<th>HDB @ 73 °F, psi</th>
</tr>
</thead>
<tbody>
<tr>
<td>PA 32312 (PA 11)</td>
<td>2500</td>
</tr>
<tr>
<td>PE 2406/PE 2708&lt;sup&gt;1&lt;/sup&gt;</td>
<td>1250</td>
</tr>
<tr>
<td>PE 3408/PE 4710&lt;sup&gt;1&lt;/sup&gt;</td>
<td>1600</td>
</tr>
<tr>
<td>PVC Type I, Grade 1, Class 12454B (PVC 1120)&lt;sup&gt;2&lt;/sup&gt;</td>
<td>4000</td>
</tr>
<tr>
<td>PVC Type II, Grade 1, Class 1433D (PVC 2116)&lt;sup&gt;2&lt;/sup&gt;</td>
<td>3200</td>
</tr>
</tbody>
</table>

<sup>1</sup> 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.

<sup>2</sup> 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.

#### 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) 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)
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.

\[ S_L(73°F) = 1567 \text{ psi} \]
\[ S_H(140°F) = 845 \text{ psi} \]
\[ T_L = 73 °F (295.93 \text{ K}) \]
\[ T_T = 78 °F (298.71 \text{ K}) \]
\[ T_H = 140 °F (333.15 \text{ K}) \]

Hence, the interpolation calculation determines that \( S_T = 1506.86 \text{ psi} \) 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.

<table>
<thead>
<tr>
<th>Range of Calculated LTHS Values</th>
<th>Hydrostatic Design Basis (HDB)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Psi (MPa)</td>
<td>Psi (MPa)</td>
</tr>
<tr>
<td>600 to &lt;760 (4.14 to &lt;5.24)</td>
<td>630 (4.34)</td>
</tr>
<tr>
<td>760 to &lt;960 (5.24 to &lt;6.62)</td>
<td>800 (5.52)</td>
</tr>
<tr>
<td>960 to &lt;1200 (6.62 to &lt;8.27)</td>
<td>1000 (6.89)</td>
</tr>
<tr>
<td>1200 to &lt;1530 (8.27 to &lt;10.55)</td>
<td>1250 (8.62)</td>
</tr>
<tr>
<td>1530 to &lt;1920 (10.55 to &lt;13.24)</td>
<td>1600 (11.03)</td>
</tr>
</tbody>
</table>

**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

(a) 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."
(b) PPI TR-22, "Polyethylene Piping Distribution Systems for Components of Liquid Petroleum Gases."
§192.123
[Removed and Reserved]

[Effective Date: 01/22/19]


GUIDE MATERIAL

1 IMPACT AND DUCTILITY

(a) 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.

(b) Significant impact or shock loads on thermoplastic pipe at low temperatures can fracture the pipe. Care should be taken to avoid dropping or striking the pipe with handling equipment, tools, or other objects.

(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.

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 1½-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.

\[
P_{\text{de-rated}} = P_{\text{§192.121}} \times DFC
\]

Where:
\(P_{\text{de-rated}}\) = De-rated design pressure, gauge, psig (kPa).
\(P_{\text{§192.121}}\) = Design pressure, gauge, psig (kPa) determined under §192.121.
\(DFC\) = Chemical Design Factor determined in accordance with 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 DFC.

4.3 References.
(a) PA pipe.
(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."
(5) GRI 96/0194, "Service Effects of Hydrocarbons on Fusion and Mechanical Performance of Polyethylene Gas Distribution Piping."
(c) PVC pipe.
SUBPART D
DESIGN OF PIPELINE COMPONENTS

§192.141
Scope.

[Effective Date: 11/12/70]

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.

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

TABLE 192.141i

§192.143
General requirements.

[Effective Date: 01/22/19]

(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.


GUIDE MATERIAL

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.


2 CORROSION CONTROL


§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.


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.
§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.

GUIDE MATERIAL

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. Adequate support, compression couplings, or other means may be used. For joining considerations, see 1, 2, and 3 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 PLASTIC VALVES

ASTM D2513 (see §192.7 for IBR) requires that all 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.

5 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.

(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.
(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

(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.

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


GUIDE MATERIAL

Equipment installed in vaults should be designed to continue to operate safely if submerged.

§192.191
[Removed and Reserved]  [Effective Date: 01/22/19]

§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.
regulator, the relief capacity may be based on the maximum capacity of the pipeline system supplying the station.

2 DETERMINATION OF RELIEF DEVICE CAPACITY

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

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

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

§192.203 Instrument, control, and sampling pipe and components.

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

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

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

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

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


GUIDE MATERIAL

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

§192.204

Risers installed after January 22, 2019.  

[Effective Date: 01/22/19]

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

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

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

[Amdt 192-124, 83 FR 58694, Nov. 20, 2018]
§192.281
Plastic pipe.

(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 D2564-12 for PVC, (incorporated by reference, see §192.7).

(3) The joint may not be heated or cooled 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 F2620-12 (incorporated by reference, see §192.7) 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 pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under §192.283.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously to establish the same temperature. The device used must be the same device specified in the operator’s joining procedure for socket fusion.

(3) An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be equivalent to or better than the requirements of the fitting 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.

(3) All mechanical fittings must meet a listed specification based upon the applicable material.

(4) All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the 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.

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 D2657.


(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.

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) 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.

(iv) 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.

(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.

2. Sidewall fittings.

(i) Determine the pipe area where the fitting is to be fused.

(ii) All surface oxidation should be removed from the pipe in the area to be fused using the tool specified in the qualified procedure.

(iii) The fitting should be positioned and clamped in the cleaned area.

(iv) The control box should be tested for proper function.

(v) 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.

(vi) The joint should be inspected in accordance with §192.273.

(b) ASTM F1055 (see §192.7) and ASTM F1290, "Standard Practice for Electrofusion Joining Polyolefin Pipe and Fittings" are references for joining plastic pipe by electrofusion.

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) 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.

<table>
<thead>
<tr>
<th>Pipe Material</th>
<th>Nominal Coefficients of Thermal Expansion (^1) ((x 10^{-5} \text{ in./in.})/(°F))</th>
<th>Expansion ((\text{in./100 ft. pipe})/(°F \text{ increase}))</th>
</tr>
</thead>
<tbody>
<tr>
<td>PA 32312 (PA 11)</td>
<td>9.0</td>
<td>0.108</td>
</tr>
<tr>
<td>PE 2406/PE 2708</td>
<td>9.0</td>
<td>0.108</td>
</tr>
<tr>
<td>PE 3408/PE 4710</td>
<td>9.0</td>
<td>0.108</td>
</tr>
<tr>
<td>PVC 1120</td>
<td>3.0</td>
<td>0.036</td>
</tr>
<tr>
<td>PVC 2116</td>
<td>4.0</td>
<td>0.048</td>
</tr>
</tbody>
</table>

\(^1\) 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.

(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 that are made according to the procedure to the following tests, as applicable:

1. The test requirements of —
   1. In the case of thermoplastic pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification.
   1. In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517-00 (incorporated by reference, see §192.7).
   1. In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055-98(2006) (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.

(3) For procedures intended for nonlateral pipe connections, perform testing in accordance with a listed specification. If the specimen elongates no more 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, the procedure must be qualified in accordance with a listed specification based upon the pipe material.

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


**GUIDE MATERIAL**

1 **WRITTEN PROCEDURES**

(a) An operator may elect to develop and qualify joining procedures or may follow the joining procedures qualified by piping or fitting manufacturers. In either instance, the operator is responsible for ensuring that the joining procedure used is qualified in accordance with the requirements of §192.283.

(b) When a manufacturer's qualified joining procedure is used, the manufacturer should supply written procedures, including pictures, 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 at least the following.

(i) Plastic compound or compounds.

(ii) Joint design.

(iii) Size and thickness range.

(iv) Method of joining.

(v) Curing or set-up time.

(vi) Temperature limits.

(vii) Temperature of the heating tool.

(viii) Proper end finishing.

(ix) Tools and equipment.

(x) Joining or repair technique. See 3 of the guide material under §192.281.

(2) **Qualification.** The procedure specification should be considered qualified if test assemblies of
joints or repairs made in accordance with the procedure specification meet the requirements of 2.2 below. The test assemblies should be cured, set, or hardened in accordance with the manufacturer's recommendations.

(b) Mechanical. (Plastic-to-plastic and plastic-to-metal)

(1) Procedure. A separate procedure should be established for each kind and type of mechanical fitting to be used for making a joint or repair. It should include at least the following.

(i) Kind and type of plastic material(s).

(ii) Other piping elements to be joined to the plastic.

(iii) Joint design.

(iv) Size and thickness range.

(v) Type of mechanical fitting.

(vi) Tools and equipment.

(vii) Joining and repair procedure.

(2) Qualification. To qualify the procedure specification, test assemblies of joints or repairs should be made in accordance with the procedure specifications and tested in accordance with 2.2 below. The test assemblies may be restrained to the same extent that they would be in service. These assemblies should be sectioned or dismantled to inspect for damage to the plastic pipe. The procedure should be rejected if there is evidence of damage that would reduce the service life of an installed joint or repair.

(3) Other considerations. See 3.5 of the guide material under §192.281.

2.2 Test requirements. (Plastic-to-plastic and plastic-to-metal)

Test assemblies should successfully meet the following requirements.

(a) Leak test. An assembly should not leak when subjected to a stand-up pressure test with air or gas.

(b) Short-term burst test. An assembly should meet the minimum burst requirements of ASTM D2513 or ASTM D2517, whichever is applicable (see §192.7 for both), for the specific kind and size of plastic pipe used in the assembly.

(c) Sustained-pressure test. An assembly should not fail when subjected to a sustained pressure test, such as the 1000 hr test described in ASTM D2513 or ASTM D2517 (whichever is applicable), for the specific kind and size of plastic pipe used in the assembly.

(d) Inspection. An assembly should be subjected to suitable nondestructive or destructive inspection to determine if the bonded area is substantially equivalent to the intended bond area.

3 UNLIKE PE COMPONENT QUALIFICATION

PE components made of different compounds and different grades of materials may be heat-fused, provided that properly qualified procedures for joining the specific compounds are used. Any combination of PE 2306, PE 2406/PE 2708, PE 3306, PE 3406, and PE 3408/PE 4710 may be joined by heat fusion using qualified procedures for specific materials. Operators attempting to qualify such procedures may be able to obtain qualified procedures from pipe manufacturers. (See guide material under §192.281 for PE heat fusion.) Additionally, the following references may be of assistance.

(a) PPI TN-13, "General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings."

(b) PPI TR-33, "Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe."

(c) PPI TR-41, "Generic Saddle Fusion Joining Procedure for Polyethylene Gas Piping."
§192.285
Plastic pipe: Qualifying persons to make joints.

(a) No person may make a plastic pipe joint unless that person has been qualified under the applicable joining procedure by —
   (1) Appropriate training or experience in the use of the procedure; and
   (2) Making a specimen joint from pipe sections joined according to the procedure that passes the inspection and test set forth in paragraph (b) of this section.
(b) The specimen joint must be —
   (1) Visually examined during and after assembly or joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the procedure; and
   (2) In the case of a heat fusion, solvent cement, or adhesive joint:
      (i) Tested under any one of the test methods listed under §192.283(a) or for PE heat fusion joints (except for electrofusion joints) visually inspected and tested in accordance with ASTM F2620–12 (incorporated by reference, see § 192.7) applicable to the type of joint and material being tested;
      (ii) Examined by ultrasonic inspection and found not to contain flaws that would cause failure; or
      (iii) Cut into at least 3 longitudinal straps, each of which is —
            (A) Visually examined and found not to contain voids or discontinuities on the cut surfaces of the joint area; and
            (B) Deformed by bending, torque, or impact, and if failure occurs, it must not initiate in the joint area.
(c) A person must be re-qualified under an applicable procedure once each calendar year at intervals not exceeding 15 months, or after any production joint is found unacceptable by testing under §192.513.
(d) Each operator shall establish a method to determine that each person making joints in plastic pipelines in the operator’s system is qualified in accordance with this section.

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

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.

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


GUIDE MATERIAL

No guide material available at present.
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2.3 In-service piping.
For repairs to in-service piping, see guide material under §192.703.

§192.313
Bends and elbows.

(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.


GUIDE MATERIAL

(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.


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.
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 rock shield material 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 shielding effects on CP currents that may occur from the installation of non-conductive materials, such as rock shielding and padding.

3.3 Rock shielding.
   Where rock shielding is used to prevent coating damage, it must be installed properly. One method of installing a wrap-type rock shielding material is to secure the rock shielding entirely around the pipe using fiberglass tape or other suitable banding material. Rock shielding 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.


GUIDE MATERIAL

1 GENERAL PRECAUTIONS

1.1 Handling.
   Care should be taken to avoid rough handling of plastic pipe. It should not be dropped or have other objects dropped upon it, nor should it be pushed or pulled over sharp projections. Caution should be taken to prevent kinking or buckling. Any kinks or buckles that occur should be cut out as a cylinder.

1.2 Considerations to minimize damage by outside forces.

1.3 Other.
   (a) 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.
   (b) Plastic pipe should be adequately supported during storage. Thermoplastic pipe and fittings should be protected from long-term exposure to direct sunlight. See 2 of the guide material under §192.59.

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 contact with the pipe 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.

<table>
<thead>
<tr>
<th>Pipe Size</th>
<th>Maximum Particle Size (inch)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPS 4 and smaller</td>
<td>1/2</td>
</tr>
<tr>
<td>NPS 6 and NPS 8</td>
<td>3/4</td>
</tr>
<tr>
<td>Larger than NPS 8</td>
<td>1</td>
</tr>
</tbody>
</table>

(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.

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."
(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 utilizing equipment and procedures that have been established and proven by test to be capable of performing the operation safely and effectively.
(b) Unless it has been determined by investigation and test that squeeze-off and reopening does not significantly affect the long-term properties of the pipe, the squeezed-off and reopened area of the pipe should be reinforced in accordance with the guide material under §192.311.
(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 PIPING FOR HIGHER PRESSURE APPLICATIONS

If PA-11 piping is installed for operating pressures up to and including 125 psig, standard installation procedures may be used. Section 192.123 limits PA-11 MAOP to 200 psig. 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 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 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.
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.

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


**GUIDE MATERIAL**

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, \(1.315\times90 = 118\); \(1.315\times125 = 164\).) 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 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

§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.


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.

(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.


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 §192.123.

(c) For the installation of PA-11 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]

§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.

<table>
<thead>
<tr>
<th>Tube Size (OD inches)</th>
<th>Support Spacing (feet)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1/2</td>
<td>4</td>
</tr>
<tr>
<td>5/8 or 3/4</td>
<td>6</td>
</tr>
<tr>
<td>7/8 or 1 1/8</td>
<td>8</td>
</tr>
</tbody>
</table>

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.


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."

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 MSS SP-115.

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.


GUIDE MATERIAL

This guide material is under review following Amendment 192-121.

1 EXCESS FLOW VALVES (EFV) INSTALLATIONS

1.1 General.
Section 192.383 requires an EFV to be installed on new or replaced service lines to single-family residences unless one or more of four conditions listed in §192.383(c) is present. The following guide material provides installation considerations for EFVs. Also, see 4 of the guide material under §192.381.

1.2 Service line supplying a single-family residence.
(a) The following illustrations (Figures 192.383A and 192.383B) show where an EFV should normally be installed on a service line 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
1.3 Service line supplying multiple single-family residences.
An operator may choose to install an EFV on a service line to multiple single-family residences. An EFV may not be practical in certain installations such as branch (split) service lines or multiple-meter manifolds due to the varying loads of multiple residences. Examples of a service line to multiple single-family residences are illustrated in Figures 192.383C and 192.383D. For other EFV installation considerations, see the conditions listed in §192.383(c) and the guide material under §192.381.
§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

No guide material available at present.
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.


GUIDE MATERIAL

No guide material necessary.

§192.452
How does this subpart apply to converted pipelines and regulated onshore gathering lines?
[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) Regulated onshore gathering lines. For any 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.

[Issued by Amdt. 192-30, 42 FR 60146, Nov. 25, 1977; Amdt. 192-102, 71 FR 13289, Mar. 15, 2006]
GUIDE MATERIAL

The operator should review the corrosion control records or perform field tests and surveys for the pipeline to be converted to ensure that cathodic protection can be applied to the pipeline to meet the requirements of Subpart I within 12 months of the conversion. 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.


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.


GUIDE MATERIAL

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.


GUIDE MATERIAL

See guide material under §192.465 regarding "areas in which active corrosion is found."
6.3 Reference.
AGA XL0702, "Distribution Pipe: Repair and Replacement Decision Manual."

7 MONITORING OF CATHODICALLY PROTECTED AREAS ON UNPROTECTED PIPELINES (§192.465(a))

7.1 "Active" corrosion areas.
See 4 and 6 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).

7.2 "Not active" corrosion areas.
See 5 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).

8 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.

9 USING ELECTRICAL-TYPE SURVEYS FOR UNPROTECTED PIPELINES

9.1 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.

9.2 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 current. CP current may 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 disbonded coating, rocks, solid-type rock shield (i.e., material that would shield CP), 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.

10 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 2 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.

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

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.

   (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.


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.
Example Leak Test Duration for Steel Pipe (hours)

<table>
<thead>
<tr>
<th>Nominal Pipe Size</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>6</th>
<th>8</th>
<th>10</th>
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<tr>
<td>Length (ft.)</td>
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<td></td>
<td></td>
<td></td>
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<td>1/2</td>
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<td>1.1/4</td>
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<td>5.1/2</td>
<td>9.1/2</td>
<td>15</td>
<td>21.1/4</td>
</tr>
</tbody>
</table>

Notes:
1. See 4(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 \( R_L \) = 5.0 scf/hr and the detectable pressure drop \( P_d \) = 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.

TABLE 192.509i

§192.511
Test requirements for service lines.

(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.


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.


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.
(b) Instructions for working effectively with the local ICS should be described as follows.
   (1) When local emergency responders have set up an Incident Command prior to the arrival of
       operator personnel:
       (i) The first operator person to arrive should introduce himself to the Incident Commander
           as the representative from the gas pipeline operator, and
       (ii) That person remains the point of contact until the incident has been made safe or until
           relieved of that duty by another operator representative.
   (2) When local emergency responders are not yet on the scene:
       (i) The first person representing the operator to arrive will serve as Command, and
       (ii) That person should assess the situation and take, or direct, all necessary actions to
           protect people, protect property, and secure the flow of gas.
   (3) If local emergency responders arrive later and set up an ICS:
       (i) The Command for the gas pipeline operator should introduce himself as the point of
           contact for the operator, brief the local Incident Commander, and
       (ii) That person should remain the point of contact until the incident has been made safe or
           until relieved of that duty by another operator representative.

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

1.3 Prompt and effective response to each type of emergency.
   Various types of emergencies will require different responses in order to evaluate and mitigate the
   hazard. Consideration should be given to the following.
   (a) Emergencies involving gas detected in or near buildings should be prioritized in order to have
       sufficient operator personnel for response. For leak classification and action criteria, refer to Guide
       Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.
       See §192.605(b)(11), which requires procedures for prompt response to reports of a gas odor in or
       near buildings.
   (b) Emergencies involving damage to buried facilities during excavation activities should be assessed
       for potential hidden and multiple leak locations.
   (c) Emergencies involving fire located on or near pipeline facilities may require those facilities to be
       isolated. If a major delivery point is involved, an alternative gas supply may be needed.
   (d) Emergencies involving an explosion on or near pipeline facilities may result in damage from fire and
       shock waves.
   (e) Emergencies involving blowing or ignited gas may hinder local emergency responders' search and
       rescue efforts.
   (f) Natural disasters, such as earthquakes, floods, hurricanes, tidal waves, or tornadoes, may affect
       the safe operation of pipeline facilities in many different ways. Operator personnel should be dispatched
       to affected areas as soon as practicable to evaluate the situation and proceed with emergency
       response, as necessary, to keep or make conditions safe. Operators of pipeline facilities subject to
       natural disasters should address these disasters in the emergency procedures and consider
       preparing a natural disaster plan including site-specific procedures, if appropriate. The procedures
       and plan may include the items listed below.
       Note: Multiple advisory bulletins have been issued regarding the potential for damage to pipeline
       facilities caused by the passage of hurricanes and flooding. For examples, see OPS Advisory Bulletin
       ADB-2015-02 (80 FR 36042, June 23, 2015; see Guide Material Appendix G-192-1, Section 2) and
       the advisory bulletin referenced in 6 of the guide material under §192.613.
       (1) Information on responsibilities for operator personnel communication and work assignments.
       (2) Information on alternative reporting locations for operator personnel in case the primary location
           is damaged or inaccessible.
       (3) Procedures to assess damage and mitigate hazardous conditions, which may include the
           following.
           (i) Establishing an operations and communications command center.
           (ii) Establishing a field command post.
(iii) Determining personnel, material, and equipment requirements.
(iv) Deploying personnel to sites and locations where they can take appropriate actions, such as shutdown, isolation, or containment.
(v) Evaluating the accessibility of pipeline facilities that may be in jeopardy such as valves and regulator stations needed to isolate the system.
(vi) Performing frequent patrols to evaluate the effects on pipeline facilities.
(vii) Determining the extent of damage to pipeline facilities.
(viii) Ensuring line markers are still in place or replaced in a timely manner for operator-defined critical locations or facilities.
(ix) Determining if facilities that are normally above ground (e.g., valves, regulators, relief devices) have become submerged and are in danger of being struck by vessels or debris. Facilities in danger of being struck by vessels should be marked with an appropriate buoy if the locations can be reached safely.
(x) Performing surveys to determine the depth of cover over pipelines and the condition of any exposed pipelines, such as those crossing scour holes or where water channels have changed. For pipelines in the Gulf of Mexico and its inlets with waters less than 15 feet deep, see §192.612.
(xi) Evaluating right-of-way conditions at water crossings during the flooding and after waters subside by performing patrols, including appropriate overflights. Notify appropriate staff of any localized or systemic flooding to determine whether pipeline crossings may have been damaged or would be in imminent jeopardy from future flooding.

Note: After the emergency response, information about the presence of pipelines and the risks posed by reduced cover should be shared with the affected landowners and with contractors, highway departments, and others involved in restoration activities following the natural 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.

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 3.2 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.


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 3.2 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.
(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.


GUIDE MATERIAL

*This guide material is under review following Amendment 192-123.*

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) 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).

(d) 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.

(e) 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).

(f) 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 role and responsibilities of the controller during normal, abnormal, and emergency operating conditions.
(5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.


GUIDE MATERIAL

(a) For information regarding replacement and repair sleeves, see 2 and 3 of the 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]
§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.


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.

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 observed, corrective action taken or recommended, and the nature and location of any deficiencies.

§192.723
Distribution systems: Leakage surveys.

(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.

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).
       (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.
   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.

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


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

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

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

GUIDE MATERIAL

No guide material necessary.

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

(a) Each operator shall conduct abandonment or deactivation of pipelines in accordance with the requirements of this section.

(b) Each pipeline abandoned in place must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

(d) Whenever service to a customer is discontinued, one of the following must be complied with:

(1) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator.

(2) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.

(3) The customer’s piping must be physically disconnected from the gas supply and the open pipe ends sealed.
(e) If air is used for purging, the operator shall insure that a combustible mixture is not present after purging.

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

(g) For each abandoned offshore pipeline facility or each abandoned onshore pipeline facility that crosses over, under or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility.

(1) The preferred method to submit data on pipeline facilities abandoned after October 10, 2000 is to the National Pipeline Mapping System (NPMS) in accordance with the NPMS "Standards for Pipeline and Liquefied Natural Gas Operator Submissions." To obtain a copy of the NPMS Standards, please refer to the NPMS homepage at http://www.npms.phmsa.dot.gov or contact the NPMS National Repository at 703-317-3073. A digital data format is preferred, but hard copy submissions are acceptable if they comply with the NPMS Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue SE, Washington DC 20590-0001; fax (202) 366-4566; e-mail InformationResourcesManager@phmsa.dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

(2) [Reserved].


GUIDE MATERIAL

1 GENERAL

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

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

2 ABANDONMENT OF TRANSMISSION PIPELINES AND DISTRIBUTION MAINS

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

2.2 Residual gas or hydrocarbons.
Abandonment should not be completed until it has been determined that the volume of natural gas or
liquid hydrocarbons contained within the abandoned section poses no potential hazard. Generally, it is advisable to purge 8-inch and larger pipe and long segments of smaller diameter pipe.

2.3 Purging.
Pipelines or mains may be purged using air, inert gas, or water. If air is used as the purging agent, precautions should be taken to ensure that no liquid hydrocarbons are present. See §192.629 and AGA XK0101, “Purging Principles and Practice” for purging of natural gas and liquid hydrocarbons.

2.4 Sealing.
Acceptable methods of sealing pipeline or main openings include, as applicable, the following.
(a) Using normal end closures, such as welded or screwed caps, screwed plugs, blind flanges, and mechanical joint caps and plugs.
(b) Welding steel plate to pipe ends.
(c) Filling ends with a suitable plug material.
(d) Pinching the ends closed.

2.5 Additional considerations in addition to purging and sealing.
In addition to purging and sealing, consideration should be given to the following.
(a) Filling the abandoned segment with water or an inert gas to prevent potential combustion hazard.
(b) Other action designed to prevent hazardous cave-ins resulting from pipe collapse caused by corrosion or external loading.

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

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

3 ABANDONMENT OF DISTRIBUTION SERVICE LINES IN CONJUNCTION WITH MAIN ABANDONMENT

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

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

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

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

4 ABANDONMENT OF SERVICE LINES FROM ACTIVE MAINS

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

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

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

5 INACTIVE PIPELINES

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

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

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

6 INACTIVE SERVICE LINES

In addition to 5.2 above, the operator should consider the following for continuing maintenance of inactive service lines.
(a) Identifying and documenting the location of inactive service lines in a record management system.
(b) Developing criteria for abandonment.
§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
No guide material necessary.

§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).


GUIDE MATERIAL
No guide material necessary.
§192.736
Compressor stations: Gas detection.

(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:

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


GUIDE MATERIAL

1 GENERAL

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.

2 VISUAL INSPECTIONS

Visual inspections should be made to determine that a satisfactory condition exists which will allow proper operation of the equipment. The following should be included in the inspection, where necessary.
(a) Station piping supports, pits, and vaults for general condition and indications of ground settlement. Prior to entering a vault that has restricted openings (e.g., manholes) or which is more than four feet deep, and while working therein, tests should be made of the atmosphere in the vault. See guide material under §192.749 for atmospheric test procedures.
(b) Station doors and gates, and pit and vault covers to ensure that they are functioning properly and that access is adequate and free from obstructions.
(c) Ventilating equipment installed in station buildings or vaults for proper operation and for evidence of accumulation of water, ice, snow, or other obstructions.
(d) Control, sensing, and supply lines for conditions that could result in a failure.
(e) All locking devices for proper operation.
(f) Posted station schematics for correctness.

3 STOP VALVES

An inspection or test of stop valves should be made to ensure that the valves will operate and are correctly positioned. Caution should be used to avoid any undesirable effect on pressures during operational checks. The following should be included in the inspection or test.
(a) Station inlet, outlet and bypass valves.
(b) Relief device isolating valves.
(c) Control, sensing, and supply line valves.

4 PRESSURE REGULATORS

4.1 General operating conditions.
Consideration should be given to taking the station out of service during inspection and testing activities. Each pressure regulator used for pressure reduction or for pressure limiting should be inspected or tested. The procedure should ensure that each regulator is in good working order, controls at its set pressure, operates or strokes smoothly, and shuts off within the expected and accepted limits. If acceptable operation is not obtained during the operational check, the cause of the malfunction should be determined and the appropriate components should be adjusted, repaired, or replaced as required. After repair, the regulator should be checked for proper operation.

4.2 Special conditions.
(a) Regulator bodies that are subjected to erosive service conditions may require visual internal inspection.
(b) More frequent inspections or additional inspections may be required as a result of construction and hydrostatic testing upstream.
(c) More frequent inspections or additional inspections may be required as a result of abnormal changes in operating conditions or unusual flows or velocities.
(d) Whenever abnormal pressures are imposed on pressure or flow devices, the event should be investigated and a determination made as to the need for inspection and repairs.
(e) Inspection and testing should be performed during times of low station throughput or when the station can be taken out of service, if practical.

5 RELIEF DEVICES

(a) The inspection or test should ensure the following.
   (1) Correct set pressure of relief devices. See 5(b) below for testing for correct set pressure.
   (2) Correct liquid level of liquid seals.
   (3) That the stacks are free of obstructions.
(b) One of the methods listed below may be used to test for correct set pressure. Test connections should include a gauge or deadweight tester so arranged that the pressure at which the device becomes operative may be observed and recorded.
   (1) The pressure may be increased in the segment until the device is activated. During the tests, care should be exercised to ensure that the pressure in the segment protected by the relief device does not exceed the limit in §192.201.
   (2) The pressure from a secondary pressure source may be added to the pilot or control line until the device is activated.
   (3) The device may be transported to a shop for testing and returned to service. When the device is to be shop-tested or otherwise rendered inoperative, adequate overpressure protection of the affected segments should be maintained during the period of time the relief device is inoperative.
(c) See §192.743 for reviewing and calculating, or testing, the required capacity of relief devices.

6 FINAL INSPECTION

The final inspection procedure should include the following.
(a) A check by personnel who are qualified (see Subpart N) for proper position of all valves. Special attention should be given to regulator station bypass valves, relief device isolating valves, and valves in control, sensing, and supply lines.
(b) Restoration of all locking and security devices to proper position.
§192.740
Pressure regulating, limiting and overpressure protection – Individual service lines directly connected to production, gathering, or transmission pipelines.
[Effective Date: 03/24/17]

(a) This section applies, except as provided in paragraph (c) of this section, to any service line directly connected to a production, gathering, or transmission pipeline 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 service lines that only serve engines that power irrigation pumps.

[Amend. 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.
§192.741

SUBPART M

(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.

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 Section VIII of the ASME Boiler and Pressure Vessel Code (see §192.7).
(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.
§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.


GUIDE MATERIAL

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.

2 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.
   (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.

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.

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.

[Amtd. 192-43, 47 FR 46850, Oct. 21, 1982; Amtd. 192-85, 63 FR 37500, July 13, 1998]
1 APPLICABILITY

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

2 HAZARDOUS ATMOSPHERES

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

3 DEVELOPMENT OF SAFETY PROCEDURES

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

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

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

§192.751
Prevention of accidental ignition.

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 an 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.

(a) Each cast iron caulked bell and spigot joint that is subject to pressures of more than 25 psi
(172 kPa) gage must be sealed with:
   (1) A mechanical leak clamp; or
   (2) A material or device which:
      (i) Does not reduce the flexibility of the joint;
      (ii) Permanently bonds, either chemically or mechanically, or both, with the bell and
spigot metal surfaces or adjacent pipe metal surfaces; and

(iii) Seals and bonds in a manner that meets the strength, environmental, and chemical compatibility requirements of §§192.53(a) and (b) and 192.143.

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


GUIDE MATERIAL

No guide material necessary.

§192.755
Protecting cast-iron pipelines.

[Effective Date: 06/01/76]

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

(a) That segment of the pipeline must be protected, as necessary, against damage during the disturbance by:

(1) Vibrations from heavy construction equipment, trains, trucks, buses, or blasting;
(2) Impact forces by vehicles;
(3) Earth movement;
(4) Apparent future excavations near the pipeline; or
(5) Other foreseeable outside forces which may subject that segment of the pipeline to bending stress.

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

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

GUIDE MATERIAL


§192.756
Joining plastic pipe by heat fusion: equipment maintenance and calibration.

[Effective Date: 01/22/19]

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

[Amtd 192-124, 83 FR 58694, Nov. 20, 2018]
§192.761
(Removed.)

[Effective Date: 02/14/04]
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.


**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. Section 192.917(b) requires that the operator comply with the IBR edition of ASME B31.8S, Appendix A even though Appendix A is titled as "non-mandatory." See 3.2 of the guide material under §192.907.

1 GENERAL

(a) Threats are analyzed to determine which threats may contribute to the failure of a pipe segment, which assessment techniques are appropriate, and which preventative and mitigative measures should be implemented. Threat analysis requires data integration and allows for the prioritization of both assessments and mitigation measures (§192.917(b)). Operators should develop processes to ensure information acquired about both covered and non-covered segments is considered in determining risk and appropriate preventative and mitigative measures.

(b) Section 192.917(b) requires that operators using a prescriptive-based program consider the information within ASME B31.8S, Appendix A. When gathering data to meet ASME B31.8S, Appendix A, if the operator is missing data, conservative assumptions should be used and documented. Operators using a performance-based program must meet or exceed the prescriptive-based program data requirements per §192.913(b).

(c) An operator may determine that pipeline segments are not susceptible to specific threats and should provide justification and documentation for eliminating the threat. The lack of required data should not justify eliminating a threat.

(d) In the following guide material, sections 2 through 11 deal with threats to steel transmission pipelines. Section 12 deals with threats to plastic transmission pipelines. Section 13 addresses data integration, Section 14 addresses risk assessment, and Section 15 provides a list of references.

2 IDENTIFICATION OF THREATS TO STEEL PIPELINES

Section 192.917 requires operators to address potential threats to pipeline integrity. See 15.1.1 below for reference containing a representative list of pipeline threats that includes examples and comments. Threats for steel pipelines are commonly grouped into the following categories.

(a) Time-dependent.

(b) Stable.

(c) Time-independent.

(d) Other.
2.1 Time-dependent threats.
Time-dependent threats are those that may grow more severe over time, such as corrosion. Analysis based on sound engineering practices may be used to help predict when these threats might become critical. Corrosion threats include the following.
(a) External corrosion.
(b) Internal corrosion.
(c) Stress corrosion cracking.

2.2 Stable threats.
A threat that has passed post-construction testing is considered stable. However, these stable threats may change as external factors (e.g., loading due to earth movements, temperature changes, pressure changes) act upon it. These threats include the following.
(a) Manufacturing defects.
(b) Welding and fabrication (construction) defects.
(c) Equipment failures.

2.3 Time-independent threats.
Time-independent threats are generally associated with events that may take place along the pipeline segment and can happen at any time. These threats include the following.
(a) Excavation damage.
(b) Incorrect operations (includes human error).
(c) Weather-related and outside force.

Note that §192.917 identifies "Human Error" as a fourth threat category. This guide material follows the ASME B31.8S threat categories and addresses the human error threat in conjunction with the incorrect operations threat.

2.4 Other threats.
Section 192.917(a) requires operators to analyze the pipeline for other threats that may not fit into one of the above categories.

3 EXTERNAL CORROSION

In evaluating the threat of external corrosion, ASME B31.8S, Appendix A1 provides a list of data that the operator is required to gather and evaluate. This threat applies to both belowground and aboveground installations.

3.1 Year of installation.
Since the threat is time dependent, the threat may increase the longer the pipe is in service. If the installation year is not known, conservative estimates should be used.

3.2 Coating type.
While coated pipe is generally less susceptible to external corrosion, all coatings are not equally effective. Coatings with insufficient adhesion or strength could result in disbondment that shields the cathodic protection (CP) current. (See guide material under §192.112). The coating application method should also be considered because a field-applied coating might not have the same performance as a mill-applied coating of the same type. Bare pipe may be considered as a coating type of "none." Thermal insulation on buried pipelines might also influence the effectiveness of the CP system because the thermal insulation might absorb water and accelerate corrosion.

3.3 Coating condition.
The following should be considered in evaluating the coating condition.
(a) Findings from prior assessments.
(b) Data from close-interval survey (CIS) and coating surveys.
(c) Data from pipeline inspection reports.
(d) Leak data.
(e) Data from atmospheric corrosion reports.
(f) Changes in CP current levels.
(g) Evaluation of coating under insulation.

3.4 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. The number or severity of corrosion defects found during assessments may be used to evaluate the 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 15.1.2 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 CP 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.

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 15.1.3 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.

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.
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 ºF. 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 ºF. 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.

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 15.1.8 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 may be correlated with near-neutral pH SCC. See 15.1.7 below.
(b) Cathodic protection. Areas with low CP readings (<850 mV) tend to be more prone to high pH SCC.
(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 may 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 15.1.8 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 15.1.9 and 15.1.13 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-but t weld.
   (8) Furnace-lap weld.
   (9) Butt weld.
   (10) Tack weld.
Appendix B to Part 192
Qualification of Pipe.

[Effective Date: 01/22/19]

I. List of Specifications
   A. Listed Pipe Specifications

   API Spec 5L—Steel pipe, "API Specification for Line Pipe" (incorporated by reference, see §192.7).
   ASTM A53/A53M—Steel pipe, "Standard Specification for Pipe, Steel Black and Hot-Dipped, Zinc-Coated, Welded and Seamless" (incorporated by reference, see §192.7).
   ASTM A672/A672M-09—Steel pipe, "Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure Service at Moderate Temperatures" (incorporated by reference, see §192.7).
   ASTM D2513–12ae1—"Standard Specification Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings" (incorporated by reference, see §192.7).
   ASTM D2517–00—Thermosetting plastic pipe and tubing, "Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings" (incorporated by reference, see §192.7).
   ASTM F2817–10 “Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair” (incorporated by reference, see § 192.7).

   B. Other Listed Specifications for Components

   ASTM D2513–12ae1“Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing, and Fittings” (incorporated by reference, see § 192.7).
   ASTM F1924–12 “Standard Specification for Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing” (incorporated by reference, see § 192.7).


ASTM F2600–09 “Standard Specification for Electrofusion Type Polyamide-11 Fittings for Outside Diameter Controlled Polyamide-11 Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F2145–13 “Standard Specification for Polyamide 11 (PA 11) and Polyamide 12 (PA12) Mechanical Fittings for Use on Outside Diameter Controlled Polyamide 11 and Polyamide 12 Pipe and Tubing” (incorporated by reference, see § 192.7).

ASTM F2767–12 “Specification for Electrofusion Type Polyamide-12 Fittings for Outside Diameter Controlled Polyamide-12 Pipe and Tubing for Gas Distribution” (incorporated by reference, see § 192.7).

ASTM F2817–10 “Standard Specification for Poly (Vinyl Chloride) (PVC) Gas Pressure Pipe and Fittings for Maintenance or Repair” (incorporated by reference, see § 192.7).

II. Steel Pipe of Unknown or Unlisted Specification

A. Bending Properties. For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.

For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53, except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

B. Weldability. A girth weld must be made in the pipe by a welder who is qualified under subpart E of this part. The weld must be made under the most severe conditions under which welding will be allowed in the field and by means of the same procedure that will be used in the field. On pipe more than 4 inches (102 millimeters) in diameter, at least one test weld must be made for each 100 lengths of pipe. On pipe 4 inches (102 millimeters) or less in diameter, at least one test weld must be made for each 400 lengths of pipe. The weld must be tested in accordance with API Standard 1104 (incorporated by reference, see §192.7). If the requirements of API Standard 1104 cannot be met, weldability may be established by making chemical tests for carbon and manganese, and proceeding in accordance with section IX of the ASME Boiler and Pressure Vessel Code (incorporated by reference, see §192.7). The same number of chemical tests must be made as are required for testing a girth weld.

C. Inspection. The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and there are no defects which might impair the strength or tightness of the pipe.

D. Tensile Properties. If the tensile properties of the pipe are not known, the minimum yield strength may be taken as 24,000 p.s.i. (165 MPa) or less, or the tensile properties may be established by performing tensile tests as set forth in API Specification 5L (incorporated by reference, see §192.7). All test specimens shall be selected at random and the following number of tests must be performed:
Number of Tensile Tests - All Sizes

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<tr>
<th>Number of Lengths</th>
<th>Tests Requirement</th>
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<tbody>
<tr>
<td>10 lengths or less</td>
<td>1 set of tests for each length.</td>
</tr>
<tr>
<td>11 to 100 lengths</td>
<td>1 set of tests for each 5 lengths, but not less than 10 tests.</td>
</tr>
<tr>
<td>Over 100 lengths</td>
<td>1 set of tests for each 10 lengths, but not less than 20 tests.</td>
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</table>

If the yield-tensile ratio, based on the properties determined by those tests, exceeds 0.85, the pipe may be used only as provided in §192.55(c).

III. **Steel pipe manufactured before November 12, 1970, to earlier editions of listed specifications.**

Steel pipe manufactured before November 12, 1970, in accordance with a specification of which a later edition is listed in section I of this Appendix, is qualified for use under this part if the following requirements are met:

A. **Inspection.** The pipe must be clean enough to permit adequate inspection. It must be visually inspected to ensure that it is reasonably round and straight and that there are no defects which might impair the strength or tightness of the pipe.

B. **Similarity of specification requirements.** The edition of the listed specification under which the pipe was manufactured must have substantially the same requirements with respect to the following properties as a later edition of that specification listed in section I of this Appendix:
   1. Physical (mechanical) properties of pipe, including yield and tensile strength, elongation, and yield to tensile ratio, and testing requirements to verify those properties.
   2. Chemical properties of pipe and testing requirements to verify those properties.

C. **Inspection or test of welded pipe.** On pipe with welded seams, one of the following requirements must be met:
   1. The edition of the listed specification to which the pipe was manufactured must have substantially the same requirements with respect to nondestructive inspection of welded seams and the standards for acceptance or rejection and repair as a later edition of the specification listed in section I of this Appendix.
   2. The pipe must be tested in accordance with subpart J of this part to at least 1.25 times the maximum allowable operating pressure if it is to be installed in a Class 1 location and to at least 1.5 times the maximum allowable operating pressure if it is to be installed in a Class 2, 3, or 4 location. Notwithstanding any shorter time period permitted under subpart J of this part, the test pressure must be maintained for at least 8 hours.

GUIDE MATERIAL

For the specified minimum yield strength of various grades of steel pipe covered by Part 192 and specifications listed in Section I of Appendix B to Part 192, see Guide Material Appendix G-192-2.
## 2 GOVERNMENTAL DOCUMENTS

**Note:** NTSB Reports are available at [www.ntsb.gov/investigations/AccidentReports/Pages/pipeline.aspx](http://www.ntsb.gov/investigations/AccidentReports/Pages/pipeline.aspx)

OPS Advisory Bulletins and Alert Notices are accessible as follows.

| 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 |
| 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-86-02  | Advisory Bulletin – Plastic Piping, Mechanical Coupling (Feb. 26, 1986; see document at PHMSA-OPS website) | §192.917 |
| 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 |

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<th>2 GOVERNMENTAL DOCUMENTS (Continued)</th>
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<tr>
<td><strong>OPS ADB-03-03</strong></td>
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| **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 |
|                       |   | §192.805  
|                       |   | §192.614 |
| **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**  | 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  
<p>| [Shown as ADB-07-01 in text] |   | §192.917 |
| <strong>OPS ADB-08-03</strong>  | Advisory Bulletin – Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems (73 FR 12796, Mar. 10, 2008) | §192.616 |
| <strong>OPS ADB-09-01</strong>  | 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 |</p>
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<tr>
<td>OPS ADB-12-03</td>
<td>Advisory Bulletin – Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation (77 FR 13387, Mar. 6, 2012)</td>
<td>§192.917</td>
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<td>OPS ADB-12-08</td>
<td>Advisory Bulletin – Inspection and Protection of Pipeline Facilities after Railway Accidents (77 FR 45417, July 31, 2012)</td>
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<td>OPS ADB-2015-02</td>
<td>Advisory Bulletin – Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes (80 FR 36042, June 23, 2015)</td>
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<td>OPS ADB-2016-01</td>
<td>Advisory Bulletin – Potential for Damage to Pipeline Facilities Caused by Severe Flooding (81 FR 2943, Jan. 19, 2016)</td>
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<td>OPS ADB-2016-05</td>
<td>Advisory Bulletin – Clarification of Terms Relating to Pipeline Operational Status (81 FR 54512, August 16, 2016)</td>
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<td>OPS ALN-88-01</td>
<td>Alert Notice – Operational failures of pipelines constructed with ERW prior to 1970 (Jan 28, 1988; see document at PHMSA-OPS website)</td>
<td>§192.917</td>
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<td>OPS ALN-89-01</td>
<td>Alert Notice – Update to ALN-88-01 (Mar 8, 1989; see document at PHMSA-OPS website)</td>
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<td>OPS-DOT.RSPA/DMT 10-85-1</td>
<td>Safety Criteria for the Operation of Gaseous Hydrogen Pipelines (Discontinued)</td>
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<td>OPS TTO No. 5</td>
<td>Technical Task Order – Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Michael Baker Jr., Inc., et al</td>
<td>§192.917</td>
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<td><strong>OPS TTO No. 8</strong></td>
<td>Technical Task Order – Stress Corrosion Cracking Study, Michael Baker, Jr., Inc., January 2005</td>
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<td>§192.613</td>
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<td><strong>PHMSA-OPS</strong></td>
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<td>Guidance Manual for Operators of LP Gas Systems</td>
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<td>Guidelines for Integrity Assessment of Cased Pipe for Gas Transmission Pipelines in HCAs</td>
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<td>&quot;Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Gas Pipelines&quot;</td>
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<td>Notice – Development of Class Location Change Waiver Criteria (69 FR 38948, June 29, 2004)</td>
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<td>§192.611</td>
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14 ILI REPORTS

14.1 Reporting format.
The operator should record the date the final report is accepted. Results of ILI surveys are often provided in one or more of the following formats.
(a) Paper copies (e.g., notebooks).
(b) Spreadsheets.
(c) Databases.
(d) Electronic media requiring vendor supplied software to view and analyze.

14.2 Report contents.
API Std 1163, Section 10 provides additional guidance on report contents, including the following.
(a) Summary (e.g., date of survey, pipeline parameters, data quality, reporting thresholds).
(b) Listing of features (e.g., odometer, distance to upstream weld, feature classification and characterization).
(c) Summary tables (e.g., pipe tally, number of features by depth range).
(d) Plots (e.g., clock position of metal loss features over the pipeline length).
(e) Pressure based assessment (e.g., methodology used, ratio of predicted failure pressure to MAOP, pipeline parameters used in calculations).

15 RESULTS VERIFICATION

When an inspection report is received, the reported data should be verified. Priority should be given to verifying any anomaly that could be categorized as an immediate repair condition. See guide material under §192.933. API Std 1163, Section 9 provides guidance on the verification process including the following steps.
(a) Process validation. See API Std 1163, Appendix B for an example checklist.
(b) Comparison with historical information.
(c) Comparison with experience for the same tool or type of tool.
(d) Verification digs and measurements. See API Std 1163, Appendix C for an example of verification digs.
(e) Comparison of verification measurements and specifications.

An operator should share the results of the verification with the ILI provider, especially if anomalies are found that are outside the tool tolerance. If anomalies are found that are outside the tool tolerances, more conservative criteria might need to be used to evaluate remedial actions (see 16 below and §192.933).

16 REMEDIATION

(a) Anomalies that indicate the pipeline integrity may be threatened must be addressed (§192.703 (b)). Sections 192.485 and 192.711 also provide repair criteria.
(b) If ILI is used to assess pipe in a covered segment, the reported anomalies in the ILI report must be evaluated and addressed in accordance with the requirements of §192.933 and ASME B31.8S, Section 7.
(c) The ILI report will generally provide a wheel count for the location of an anomaly. The operator will need to convert this wheel count into a field location. NACE SP0102, Section 8.2.5 and API Std 1163, Appendix C provide guidance for locating anomalies.
(d) For repair methods, see guide material under §192.713.

17 REFERENCES

(a) The following industry publications provide guidance on running ILI tools.
   (1) API Standard 1163, "In-line Inspection Systems Qualification Standard."
   (2) NACE SP0102 (formerly RP0102), "In-Line Inspection of Pipelines."
   (3) ASNT ILI-PQ, "In-line Inspection Personnel Qualification and Certification."
(4) ASME B31.8S, "Managing System Integrity of Gas Pipelines" (see §192.7 for IBR).

(5) NACE 35100, Technical Committee Report, "In-Line Nondestructive Inspection of Pipelines."

(b) Table 17.1 below lists respective references in industry documents related to specific ILI topics.

<table>
<thead>
<tr>
<th>TOPIC</th>
<th>SECTION or PARAGRAPH REFERENCE</th>
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<tr>
<td></td>
<td>ASME B31.8S</td>
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<td>Pipeline Design</td>
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<tr>
<td>Tool Selection</td>
<td>6.2</td>
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<td>Pipeline Considerations</td>
<td>6.5</td>
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