July 18, 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,

[Signature]

Secretary
GPTC Z380
GPTC GUIDE FOR GAS TRANSMISSION, DISTRIBUTION, AND GATHERING PIPING SYSTEMS

2018 EDITION

ADDENDUM 3, JULY 2019

The changes in this addendum are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, or a block symbol (▌) where needed. There were no Federal Regulation updates for this period. 12 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 6 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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2018 Edition

Addendum 3, July 2019

An American National Standard
PLEASE NOTE
Addenda to this Guide will also be issued periodically to enable users to keep the Guide up-to-date by replacing the pages that have been revised with the new pages. It is advisable, however, that pages which have been revised be retained so that the chronological development of the Federal Regulations and the Guide is maintained.

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PREFACE

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

- Part 191 - Transportation of Natural and Other Gas by Pipeline: Annual Reports, Incident Reports, and Safety-Related Condition Reports
- Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards

Parts 191 and 192 are typically referred to hereinafter as the "Regulations."

The recommendations contained in the Guide are based on sound engineering principles developed by a committee balanced in accordance with accepted committee procedures and must be applied by the use of sound and competent judgment. All guide material is of equal importance and validity, whether immediately following the Regulations or in Guide Material Appendices.

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

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

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.agamineral.org/gptc or paper copies may be purchased at https://www.agamineral.org/aga-publications for a nominal fee. A new edition, incorporating all previous addenda that have been published, is usually issued every three years.

The historical reconstruction of the Regulations is available in AGA X69804, "Historical Collection of Natural Gas Pipeline Safety Regulations." It includes the original version of Parts 191 and 192 and all their amendments through Amdts. 191-15 and 192-93 (published September 15, 2003). The Federal Register preamble to the amendments is included as well. This collection of all earlier amendments has been established as a readily accessible reference to supplement the Guide or to aid research activity. However, considering the electronic availability of amendments starting in 2004, refer to the Federal Register web site for later amendments.
The format of the Guide includes the title of each numbered section of the Regulations and is followed by the effective date of the latest amendment activity or effective date of the original version if no amendment has been issued. The Regulation is followed by a list of amendment or control numbers for the respective section and the applicable guide material as developed by the Committee.

The Guide is maintained using the continuous maintenance process. Proposals to revise any part may be submitted to the Committee at any time. A Form for Proposals on ANSI GPTC Z380.1 is provided at the end of the Guide and may also be obtained on the GPTC website at www.aga.org/gptc. Use this form and submit proposals to: GPTC Secretary, American Gas Association, 400 N. Capitol Street, NW, Washington, D.C. 20001. (or email GPTC@aga.org)

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

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<td>Anderson, Erik Northwestern Energy, Butte, MT</td>
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<td>Armstrong, Glen F. Retired, Warrenville, IL</td>
<td>X</td>
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<td>Bareither, Randy K. Avista Utilities, Spokane, WA</td>
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<tr>
<td>Bateman, Stephen C. UGI, PA</td>
<td>X</td>
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<tr>
<td>Beatty, Stephen A. Louisville Gas &amp; Electric, Louisville, KY</td>
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## GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

<table>
<thead>
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<tr>
<td>Secretary: Sec</td>
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| UGI Utilities, Reading, PA                            |           |             |          |        |
| Blanchard, Michelle                                   | X         | X           | X        |
| Alliant Energy                                        |           |             |          |        |
| Bull, David E.                                        | X         | X           | Chair    | X      |
| ViaData LP, Noblesville, IN                           |           |             |          |        |
| Burdeaux, DeWitt                                      | X         | X           | X        | X      |
| TRC Solutions, Kansas City, MO                        |           |             |          |        |
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| Chin, John S.                                         | X         | X           | X        | X      |
| TransCanada Corp., Troy, MI                           |           |             |          |        |
# GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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

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| McKay, Erin | Hilcorp Alaska, LLC, Anchorage, AK | X | X | X |
| McKenzie, James E. | Atmos Energy Corp., Jackson, MS | X | X | Chair | Sec | X |
| McLaren, Theron C. (Chris) | PHMSA, Washington, DC | X | X | X | X |
| Medcalf, Rich | Indiana Utility Regulatory Commission, Indianapolis, IN | X | X | X |
| Miller, D. Lane | TRC Solutions, Kansas City, MO | X | Sec | X | X | Sec |
| Moon, Douglas | SO Cal Gas | X | X | X | X |
| Naper, Robert C. | Energy Experts International, Canton, MA | X | X | X | X | X |
| O’Leary, Daniel | Timberline Tool, Kalispell, MT | X | X | X | X |
| Oleksa, Paul E. | Oleksa & Assoc., Broadview Heights, OH | X | X | X | X | X |
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- **Truair, Ryan**
  - NW Natural, Portland, OR
  - X

- **Ulanday, Alfredo (Fred) S.**
  - EN Engineering, Warrenville, IL
  - X X

- **Veerapaneni, Ram**
  - Retired, Canton, MI
  - X X X

- **Volkstadt, Frank R.**
  - Volkstadt & Associates, Madison, OH
  - X Sec

- **Waller, Jacob**
  - Washington Gas Light Company, Springfield, VA
  - X X X

- **Walton, Jim**
  - Mears Group Inc., Carrollton, TX
  - X X

- **Wartluft, David C.**
  - Continental Industries, Broken Arrow, OK
  - X X

- **Webb, Thomas**
  - Peoples Gas Light & Coke
  - X

- **Wilson, Randy**
  - Spire, Birmingham, AL
  - X X

- **Wong, Anson**
  - Southern California Gas Company, Los Angeles, CA
  - X X X
(d) **Reporting.** An operator must use the OPID issued by PHMSA for all reporting requirements covered under this subchapter and for submissions to the National Pipeline Mapping System.


**GUIDE MATERIAL**

(a) Section 191.22(c)(1) requires a notice not later than 60 days before certain construction activities occur. Examples of construction activities that might trigger this advance notification to PHMSA under §191.22(c)(1) include the following.

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


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

(c) Operators must notify PHMSA in accordance with §191.22(c)(1)(vi) when the commodity being transported changes from one listed below to another.

1. Natural gas.
2. Synthetic gas.
3. Hydrogen gas.
4. Propane gas.
5. Landfill gas.
6. Other gas.

(d) See guide material under §192.14 for examples of conversion of service that would also require notice to PHMSA in accordance with §191.22(c)(1)(vi).

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**§191.23**

**Reporting safety-related conditions.**

[Effective Date: 01/18/17]

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

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

2. In the case of an underground natural gas storage facility, including injection, withdrawal, monitoring, or observation well, general corrosion that has reduced the wall thickness to less than that required for the maximum well operating pressure, and localized corrosion pitting to a degree where leakage might result.
§191.23

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

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

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

(6) Any malfunction or operating error that causes the pressure of a pipeline or underground natural gas facility or LNG facility that contains or processes gas or LNG to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the margin (build-up) allowed for operation of pressure limiting or control devices.

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

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

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

(b) A report is not required for any safety-related condition that-

(1) Exists on a master meter system or a customer-owned service line;

(2) Is an incident or results in an incident before the deadline for filing the safety-related condition report;

(3) Exists on a pipeline (other than an LNG facility or Underground Natural Gas Storage Facility) that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway; or

(4) Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related condition report, except that reports are required for conditions under paragraph (a)(1) of this section other than localized corrosion pitting on an effectively coated and cathodically protected pipeline.


GUIDE MATERIAL

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

(b) See Guide Material Appendix G-191-3 for a chart useful in determining if reports must be filed.

(c) See guide material under §192.617 for failure investigation, when applicable.

(d) If the MAOP plus the build-up allowed for operation of pressure-limiting or control devices on a transmission line is exceeded, the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011
§191.23

(ACT)(Section 23(b)) states that the operator is to notify the Secretary of Transportation, and appropriate state agencies if the pipeline is subject to state regulations, or before the fifth calendar day of the exceedance. PHMSA-OPS issued Advisory Bulletin ADB-2012-11 (77 FR 75699, Dec. 21, 2012; reference Guide Material Appendix G-192-1, Section 2) to advise owners and operators of gas transmission pipeline facilities of new reporting requirements in the Act. The Act states that exceedance is to be reported even if the condition is corrected within the reporting timeframe. The Advisory Bulletin requests operators to submit information comparable to that required for a safety-related condition (see Guide Material Appendix G-191-4). The operator should note that the reporting requirement for an exceedance is calendar days, as opposed to the safety-related conditions requirement of working days that does not include Saturdays, Sundays, or federal holidays.

§191.25

Filing safety-related condition reports.

[Effective Date: 10/01/15]

(a) Each report of a safety-related condition under §191.23(a) must be filed (received by OPS within five working days, not including Saturday, Sunday, or Federal Holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described in a single report if they are closely related. Reports may be transmitted by electronic mail to InformationResourcesManager@dot.gov or by facsimile at (202) 366-7128.

(b) The report must be headed “Safety-Related Condition Report” and provide the following information:

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


GUIDE MATERIAL

(a) The preamble to Amendment 191-7 ("Interpretation and Statement of Policy Regarding Discovery of Safety-Related Conditions by Smart Pigs and Instructions to Personnel") states:

"Discovery of a potentially reportable condition occurs when an operator's representative has adequate information from which to conclude the probable existence of a reportable condition. An operator would have adequate information for each anomaly that is physically examined. Absent
physical examination, discovery may occur after the data are calibrated if the "adequate information" test is met. However, the adequacy of the information that pig data provide about anomalous conditions is contingent on a concurrent indication from a number of factors from which an operator could conclude the probable existence of a reportable condition. Among these are the sophistication of the pig being used, the reliability of the data, the accuracy of data interpretation, and any other factors known by the operator relative to the condition of the pipeline.”

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

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

### §191.27

Removed.)

**Effective Date:** 10/01/15

### §191.29

**National Pipeline Mapping System.**

**[Effective Date:** 10/01/15]

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


2. The name of and address for the operator.

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

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

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

**GUIDE MATERIAL**

No guide material necessary.
SUBPART E
WELDING OF STEEL IN PIPELINES

§192.221
Scope.

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

GUIDE MATERIAL

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

§192.223
(Removed.)

[Effective Date: 07/07/86]

§192.225
Welding procedures.

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

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

GUIDE MATERIAL

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

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

§192.227
Qualification of welders.

[a] [Effective Date: 03/24/17]

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

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

[Amdt. 192-18, 40 FR 10181, Mar. 5, 1975 with Amdt. 192-18A, 40 FR 27222, June 27, 1975; Amdt. 192-
22, 41 FR 13589, Mar. 31, 1976; Amdt. 192-37, 46 FR 10157, Feb. 2, 1981; Amdt. 192-43, 47 FR 46850,
Amdt. 192-75 Correction, 61 FR 38403, July 24, 1996; Amdt. 192-78, 61 FR 28770, June 6, 1996 with
192-103, 71 FR 33402, June 9, 2006; Amdt. 192-103, 72 FR 4655, Feb. 1, 2007; Amdt. 192-119, 80 FR
168, Jan. 5, 2015; Amdt. 192-120, 80 FR 12762, Mar. 11, 2015; Amdt. 192-123, 82 FR 7997, Jan. 23, 2017]

GUIDE MATERIAL

It is the operator's responsibility to ensure that all welding is performed by qualified welders and welding
operators. The ability of welders and welding operators to make sound welds should be determined by test
welds using previously qualified welding procedures. The evaluation of test welds may be conducted by
qualified operator personnel or testing laboratories.
equipment, making it necessary to use a passive or induced current locating device.
(c) Mapping. Accurate mapping of plastic pipe with dimensions referenced to permanent landmarks (e.g., lot lines, street centerlines) is an acceptable method of locating plastic pipe.
(d) Passive devices. Tuned coils or other passive devices may be buried at strategic points along a plastic pipeline. These devices can be located from above ground by means of an associated locating instrument.

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

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

3.1 General.
(a) The casing or abandoned pipeline should be prepared to the extent necessary to remove any sharp edges, projections, dust, welding slag, or abrasive material which could damage the plastic during or after insertion.
(b) A support sleeve or plug should be used to prevent the plastic pipe from bearing on the end of the casing or abandoned pipeline.
(c) Maps or other records should indicate plastic pipe that is inserted in a casing or an abandoned pipeline.
(d) A means of locating inserted plastic pipe should be provided (see 2.4 and 2.5 above).

3.2 Special considerations.
(a) That portion of the plastic pipe which spans disturbed earth should be protected by bridging, by compaction of the soil under the plastic pipe, or by other means to prevent the settling of the backfill from shearing the plastic pipe.
(b) The portion of the plastic pipe exposed due to the removal of a section of casing pipe or abandoned pipeline should have sufficient strength or be protected with bridging or other means, so as to withstand the anticipated external soil loadings.
(c) Protective sleeve installations that are designed to mitigate the stresses imposed onto the plastic pipe in the transition area should be considered if undue stresses are anticipated, or if recommended by the manufacturer. The installation of protective sleeves, in addition to providing adequate backfill and compaction around the transition area, reduces excessive bending and shear stresses. For protective sleeves, see guide material under 192.367.
(d) Cased plastic pipe can contract due to cold gas or low ambient temperature. See 3.5(f) of the guide material under §192.281.
(e) Where a gas leak migrating through the annular space between the plastic pipe and the casing or abandoned pipeline could result in a hazardous condition, consideration should be given to plugging the annular space at one or both ends. Plugs may also be provided at intermediate points, such as where the casing or abandoned pipeline is cut, to permit the installation of a service tee or a lateral main. Care should be used in the selection of the plugging material to avoid damage to the plastic pipe. Both urethane foam and grout have been found to be effective for this purpose.
(f) If water that has accumulated between the casing or abandoned pipeline and the carrier pipe freezes, the carrier pipe can be constricted (affecting the capacity) or damaged causing a leak. One or more of the following steps can be taken to minimize this possibility.
   (1) Sizing the pipe so that the formation of ice between the carrier and the casing or abandoned pipeline will not constrict the carrier pipe to the extent that service is affected.
   (2) Providing for drainage at the lower points in the casing or abandoned pipeline.
   (3) Inserting a filler, such as a closed cell foam material, in the annular space.

3.3 Reference.
See 8 below for plastic pipe encased on bridges.
4  PROVISIONS FOR BENDS

4.1  General considerations.
The bends should be free of buckles, cracks, or other evidence of damage.

4.2  Bending radius.
Plastic pipe may not be deflected to a radius smaller than the minimum recommended by the manufacturer for the kind, type, grade, wall thickness, and diameter of the particular plastic pipe used.

5  SQUEEZE-OFF AND REOPENING THERMOPLASTIC PIPE FOR PRESSURE CONTROL PURPOSES

5.1  Preliminary investigation.
Before thermoplastic pipe is squeezed-off and reopened, investigations and tests should be made to determine that the particular type, grade, size, and wall thickness of pipe of the same manufacture can be squeezed-off and reopened without causing failure under the conditions which will prevail at the time of the squeeze-off and reopening. References for squeeze-off procedures, tools, and precautions are included in the following.
(a) AGA XR0603, "Plastic Pipe Manual for Gas Service."
(b) GRI-92/0147.1, "Users’ Guide on Squeeze-Off of Polyethylene Gas Pipes."
(d) ASTM F1041, "Standard Guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing."
(e) ASTM F1563, "Standard Specification for Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing."

5.2  Field consideration.
(a) The work should be done using equipment and procedures that have been established and proven by test to be capable of performing the operation safely and effectively.
(b) If it has been determined by investigation and testing that squeeze-off and reopening affects the long-term properties of the pipe, the squeezed-off and reopened area of the pipe should be reinforced or the pipe segment replaced.
(c) To prevent squeeze-off at the same point, a permanent mark or clamp should be put on the plastic pipe at the location of the squeeze point.

6  DAMAGE PREVENTION

(a) For temporary markings, see 4 of the guide material under §192.319.
(b) For damage prevention considerations while performing directional drilling or using other trenchless technologies, see Guide Material Appendix G-192-6.

7  PLASTIC PIPE TEMPORARILY INSTALLED ABOVE GROUND

7.1  Aboveground exposure to sunlight.
Before using plastic pipe above ground, the operator should obtain the recommended maximum exposure time from the manufacturer and determine the date of manufacture from the Pipe Production Code marked on the pipe. If the operator cannot accurately document the actual time that pipe was stored outdoors, the entire time since the date of manufacture should be considered as aboveground exposure.

7.2  Protection from external forces.
Means to protect the pipe may include:
(a) Barricades.
(b) Fencing.
(c) Elevation support. To prevent strain on the plastic pipe due to sagging or wind forces, elevation support should be provided. A reference for determining support spacing is PPI Handbook of Polyethylene Pipe, Chapter 8, "Above-Ground Applications for Polyethylene Pipe."
(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."

(b) Performance criteria: MSS SP-142, "Excess Flow Valves for Fuel Gas Service, NPS 1½ through 12."


2.1 Pressure or related limitations.

(a) The EFV should function without unintended closure within the manufacturer's operating pressure limits.

(b) The EFV should not be damaged by test pressures or corresponding flow rates that may be uncontrolled.

2.2 Reset of the EFV.

The EFV should be capable of being reset through automatic or manual means. Currently, there are two basic designs:

(a) EFVB: Automatic. When selecting an EFVB, which provides automatic reset, consideration should be given to the reset time and the volume under the worst-case system conditions.

(b) EFVNB: Manual. The EFVNB may be used to provide complete shutoff of all gas flow. Once activated, a manual reset capability should be available, such as back-pressuring the line. The maximum leakage through an EFVNB should be in accordance with either MSS SP-115 or MSS SP-142, as applicable.

2.3 Flow rates during operation.

(a) According to §192.381(a) for excess flow valves required by §192.383(b), the EFV closure flow rate is required to be no less than the manufacturer's rating at 10 psig. Further, the closure flow rate is to be no greater than 50% above the manufacturer's established rate at the respective EFV inlet pressure. For other situations, the closure flow rate should be no less than the manufacturer's established limits.

(b) When subjected to snap-acting loads, the EFV should not close as the flow rate changes abruptly from a base steady flow to one equal to, or greater than, the typical customer's peak load, provided that the load is not greater than the minimum trip point of the EFV.

Addendum 3, July 2019
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.
Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and minimizing the possibility of a recurrence.

GUIDE MATERIAL

1 GENERAL

(a) Data on all failures and leaks should be compiled to support compliance with §192.613. A failure investigation should be performed to determine the cause of the failure and minimize the possibility of a recurrence.

(b) For information on failures of PE pipe, see 3 of the guide material under §192.613.

(c) For information on reporting failures of mechanical fittings, see guide material under §191.12.

2 TYPES AND NATURE OF FAILURES THAT SHOULD BE ANALYZED

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

3 FAILURE INVESTIGATION

(a) Failure investigation and subsequent analysis should determine the root cause(s) of the failure. The investigation may be as simple as assembling an internal review group or as complex as conducting a full-scale failure investigation with laboratory analysis of a failed component. The information for completing a 30-day incident report form contained in Part 191 may constitute an adequate analysis of a reportable failure or leak. See §§191.9 and 191.15.

(b) The general process for performing root-cause analysis is as follows.

(1) Assemble the review team.

(2) Define the problem and gather data and documentation.

(3) Identify factors that contributed to the problem (i.e., causal factors).

(4) Find the root cause for each causal factor, such as people, equipment, material, process, or outside influence.

(5) Develop and assign recommendations.

(6) Distribute recommendations and review the operator’s procedures.

(7) Implement the recommendations.

(c) For failures of mechanical fittings or joints, consider following the evaluation steps in 3 of the guide material under §191.12.

4 RESPONSE TO FAILURE

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

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

5.2 Other failures.
(a) Gather sufficient data to complete the general process for performing root-cause analysis. See 3 above.
(b) For a failure that does not elevate to the level of an incident, an operator may follow the data collection steps. See 5.1 above.

6 INVESTIGATION

A subject matter expert (SME) individual or team can perform an extensive evaluation or a more simplified evaluation based on the nature of a system and its operation. The SME should be knowledgeable by training or experience in the procedures for the investigation of an incident or other failure.

6.1 Incident.
When a detailed analysis is to be made, an SME investigation team should be designated. The investigation should include the following.
(a) Determination of the probable cause.
(b) Evaluation of the initial response.
(c) The need for system improvements, if necessary.
(d) The need for improvements in response, management, and investigation.

6.2 Other failures.
Assign an internal SME individual or team.

6.3 Evaluation
Consider testing the involved facilities, performing a leak or other survey of the involved area, or inspecting for signs of recent excavation activity.

7 SPECIMENS
As used in this section, a specimen is any physical evidence such as a pipe, joint, fitting, meter, other material, soil, or other sample that may be collected as part of a failure investigation.

(a) Procedures for excavating the area over and around the specimen at the failure location should include precautions such as hand digging, vacuum excavation, or other appropriate methods to avoid causing damage to any potential specimen, pipelines in the vicinity of the excavation near the specimen, or the surrounding environment.
(b) Procedures should be prepared for selecting, collecting, preserving, labeling, and handling of specimens.
(c) Procedures for collecting plastic or metallurgical specimens should include precautions against changing the granular structure in the areas of investigatory interest (e.g., avoid heat effects from cutting and outside forces due to tools and equipment).
(d) Procedures may be necessary for proper sampling and handling of soil and groundwater specimens where corrosion may be involved.

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

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

8 TESTING AND ANALYSIS

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

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

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

9 REFERENCE

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

§192.619

Maximum allowable operating pressure:
Steel or plastic pipelines.

[Effective Date: 12/22/08]

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

1. The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:
   (i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, see §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or
   (ii) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

2. The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:
   (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
   (ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:
§192.619

SUBPART L

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

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

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

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).
To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:

<table>
<thead>
<tr>
<th>(11) Making repairs (continued)</th>
<th>Take the following additional step:</th>
</tr>
</thead>
<tbody>
<tr>
<td>(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.</td>
<td></td>
</tr>
<tr>
<td>(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure.</td>
<td></td>
</tr>
<tr>
<td>(iii) If paragraph (d)(11)(ii) of this section does not require immediate repair, repair a defect within one year if any of the following apply:</td>
<td></td>
</tr>
<tr>
<td>(A) The defect meets the criteria for repair within one year in §192.933(d).</td>
<td></td>
</tr>
<tr>
<td>(B) The alternative maximum allowable operating pressure was based on a design factor of 0.80 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure.</td>
<td></td>
</tr>
<tr>
<td>(C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure.</td>
<td></td>
</tr>
<tr>
<td>(D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure.</td>
<td></td>
</tr>
<tr>
<td>(iv) Evaluate any defect not required to be repaired under paragraph (d)(11)(ii) or (iii) of this section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.</td>
<td></td>
</tr>
</tbody>
</table>

(e) **Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure?** Notwithstanding the required capacity of pressure relieving and limiting stations otherwise required by §192.201, if an operator establishes a maximum allowable operating pressure for a pipeline segment in accordance with paragraph (a) of this section, an operator must:

1. Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and

2. Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

GUIDE MATERIAL

1 SCOPE

This guide material applies to an alternative MAOP for new or existing steel pipelines. An alternative MAOP for an existing pipeline is applicable as follows.
(a) Preventing a reduction of MAOP if the class location changes, or
(b) Increasing MAOP, such as in response to a change in throughput.

To have an alternate MAOP, an existing pipeline is required to meet the design, construction, operations, and maintenance requirements in §192.620. Requirements differ for pipelines that are already in operation versus those that are newly constructed.

2 GENERAL

Certain pipelines or pipeline segments as listed below may not use an alternative MAOP (see §192.620(b)).
(a) Pipeline segments in Class 4 locations.
(b) Pipeline segments of a grandfathered pipeline already operating at a higher stress level, but not constructed in accordance with current requirements (see §192.620(c)(8)).
(c) Pipeline segments with bare or ineffectively coated pipe (disbonded or shielded), which may not allow the cathodic protection (CP) to pass through the coating.
(d) Pipelines that did not have CP installed within 12 months of initial operation.
(e) Pipelines with wrinkle bends.
(f) A pipeline with failures, such as seam failure during hydrostatic testing, unless a root cause or failure analysis (including metallurgical examination of the failed pipe) has determined the failure is not indicative of a systemic problem.
(g) Pipeline segments with pipe manufactured by certain processes, such as low-frequency electric resistance welding, or pipe with a longitudinal joint factor less than 1 (see §192.113).
(h) Pipeline segments that cannot accommodate internal inspection devices.
(i) Pipelines constructed with used or reconditioned pipe.
(j) Non-steel pipelines.
(k) Pipelines not monitored and controlled by supervisory control and data acquisition (SCADA) systems.
(l) Pipelines that have mechanical couplings in lieu of girth welds.
(m) Pipelines transporting gas with a carbon dioxide content of more than 3 percent (see §192.620(d)). Blending should not be used to lower the carbon dioxide content.
(n) Existing pipelines that do not meet the additional design requirements of §192.112, or the additional construction requirements of §192.328.
(o) Existing pipelines that do not have at least 95 percent of the girth welds non-destructively tested.

3 ESTABLISHING AN ALTERNATIVE MAOP

(a) Notification.
   (1) Section 192.620(c)(1) requires that notification for in-service pipelines be provided to PHMSA and each applicable state pipeline safety agency at least 180 days before operating at the alternative MAOP. This section also requires notification of planned alternative MAOP design and operation for new pipelines at least 60 days prior to the start date of either pipe manufacturing or construction activities, whichever occurs first. Regulatory agencies may use this time for inspection of the facility, records, plans, and procedures.

   (2) Notification should include the following.
      (i) Operator name and ID number.
      (ii) Pipeline name.
      (iii) Location and simple map of the facility.
(iv) Proposed MAOP of the facility.
(v) Existing MAOP, if the facility is already in use, and reason for changing MAOP.
(vi) Other involved facilities, such as compressor stations or regulator stations.

(3) Early notification might help avoid delays by allowing PHMSA time to review the procedural manual, specifications, pipe manufacturing records, external coating, field construction activities, Operator Qualification (OQ) program, and other documentation.

(4) The advance notification might not be considered complete until all required documentation has been received by PHMSA. Notification should be considered complete when confirmation is received by the operator.

(5) Section 192.620(c) requires that additional certification be submitted at least 30 days before the pipeline can operate at the higher MAOP. The 30-day notification requires certification by a senior executive officer that the pipeline meets the requirements for alternative MAOP operation, which include the following.

(i) Changes to operating and maintenance (O&M) procedures for the more rigorous and additional O&M requirements.
   (A) Right-of-way (ROW) management plans.
   (B) Depth-of-cover maintenance program.
   (C) Site-specific external and internal corrosion plans.
   (D) Integrity assessment plans.
   (E) Repair criteria.

(ii) Changes to the damage prevention program, which includes ensuring that the program meets or exceeds Common Ground Alliance (CGA) or equivalent best practices.

(iii) Changes to the OQ program to ensure that construction tasks are covered.

(iv) Identification and assessment of threats.

(v) Changes to the public awareness program.

(vi) Changes to emergency plans to address the additional needs of responding to emergencies at higher operating stress levels.

(vii) Required SCADA monitoring and control is in place.

(b) Calculating MAOP.

(1) Alternative MAOP is established based upon design and test factors prescribed in §192.620(a), which are listed below.

<table>
<thead>
<tr>
<th>Class Location</th>
<th>Alternative Design Factor</th>
<th>Stress level</th>
<th>Alternative Test Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.80</td>
<td>80%</td>
<td>1.25</td>
</tr>
<tr>
<td>2</td>
<td>0.67</td>
<td>67%</td>
<td>1.50</td>
</tr>
<tr>
<td>3</td>
<td>0.56</td>
<td>56%</td>
<td>1.50</td>
</tr>
<tr>
<td>4</td>
<td>NA</td>
<td>NA</td>
<td>NA</td>
</tr>
</tbody>
</table>


Table 192.620i

(2) Alternative design factors for road crossings, fabrications, headers, mainline valve assemblies, separators, meter stations, and compressor stations are available for existing facilities, and can only be used on existing facilities for confirmation at the higher MAOP.

(3) If operators design road/railroad crossings, fabrications, headers, mainline valve assemblies, separators, meter stations, and compressor stations on new pipelines operating under an alternative MAOP in accordance with the design factors in 49 CFR §192.111(b), (c), or (d), then these short segments of pipelines or facilities will not be operating at an alternative MAOP and are not subject to the alternative MAOP regulation.
4 ADDITIONAL OPERATION AND MAINTENANCE REQUIREMENTS

(a) General. There are additional operating and maintenance requirements that are intended to address certain risks for gas pipelines, such as excavation damage and corrosion. These include requirements for an operator to evaluate and address the issues associated with operating at higher pressures. Section 192.620(c)(2)(ii) requires that the operator make the necessary changes to their O&M procedures to include the requirements in §192.620(d) before commencing operation at an alternative MAOP.

(b) Identifying and evaluating threats. Some provisions of §192.620(d) are more restrictive than Subpart O. The Regulations address many known threats, however, other threats may exist or develop that affect the pipeline integrity. It is up to the operator to identify and evaluate possible pipeline threats in accordance with ASME B31.8S (see §192.7 for IBR). To address the comparison of conventional MAOP to the risk of an alternative MAOP pipeline, the operator should develop a risk ranking that identifies and compares the increased risk.

(c) Notifying the public (§192.620(d)(2)). Additional public information is necessary to inform any stakeholders living along the ROW. At a minimum, the public notification includes either the 220-yard corridor required for class location, or the calculated potential impact radius (PIR) for the segment, whichever is the greater distance. An operator should consider adding additional footage to these distances.

Some activities performed as requirements for public awareness may also be used to satisfy similar program requirements under §§192.614, 192.615, 192.616, and 192.935.

1. An operator may want to review the messages sent to stakeholders along an alternative MAOP pipeline to ensure the special nature of the pipeline is addressed. The messages should include the MAOP and product type, additional O&M activities and inspections, and the additional integrity requirements. This may require different types of communication, including social media.

2. Where the alternative MAOP pipeline is in a High Consequence Area (HCA) already identified per Subpart O, then no additional notification may be necessary beyond that required under Subpart O.

3. An operator may want to consider more frequent evaluations for effectiveness on alternative MAOP pipelines.

(d) Responding to an emergency in HCAs. While additional response measures are required for HCAs, the operator may choose to incorporate these additional requirements beyond the HCA limits. The operator should maintain a list of response times based on actual driving of the route. The operator may want to consider the following.

1. Reviewing response time from the normal daytime crew departure location.

2. Reviewing response time during non-working hours for first responders.

3. Altering the responding location if drive times are not within required limits.

4. Periodically reviewing response time to determine if any significant changes to roads or driving conditions might alter response times.

(e) Protecting the right-of-way (§192.620(d)(4)). The operator must have a written plan to address ROW protection. Operators may already address ROW protection and soil monitoring issues in their damage prevention, continuing surveillance, patrolling, or other O&M procedures, such that an additional plan may not be required. To protect from outside force damage, the operator must maintain the pipeline depth of cover. If observed conditions indicate a loss of cover, the operator is required to perform a depth-of-cover study and replace the cover or remediate by alternative methods (§192.620(d)(4)(iii)). Alternative protection must provide equivalent protection and the operator must demonstrate this equivalence.

1. Transmission pipelines are often located in areas such as hills and mountainous terrain, which can exhibit unstable soils, (e.g., clay). It is important to ensure that stresses caused by soil movement do not damage pipelines in these areas with reduced design safety factors.
5 INTEGRITY MANAGEMENT REQUIREMENTS

(a) Direct assessment methods (e.g., close interval survey (CIS), DCVG) must be used for periodic assessment (§192.620(d)(7)(iv)). An operator may want to modify pipe inspection reports required by §192.459 to provide additional data for analysis.

(b) An operator must consider tool tolerances and accuracy when scheduling remediation response (§192.620(d)(11)(i)(B)). An operator should retain the documentation and justification for the values used, which may include unity plots. Under-calling defects may necessitate regrading of the tool run.

(c) The operator should apply additional restrictions for direct assessment pipe examinations for internal or external corrosion, or SCC, including detailed measurements, nondestructive examination (NDE), and characterization of the defect or anomaly.

(d) The operator should adjust reporting thresholds to ensure that small defects are identified for analysis.

(e) Existing repair criteria should account for smaller-type defects and faster repair times.

(f) The operator should have a method to communicate the results of dig inspections back to the ILI vendor for confirming and improving accuracy of the ILI data and improving vendor algorithms for data analysis.

(g) The operator must integrate all results, including ILI data, external corrosion data and surveys, internal corrosion data, depth-of-cover data, and other data as appropriate for analyzing threats and risks (§192.620(d)(7)(iii)).

(h) The operator must define action thresholds, such as immediate or one-year, based on design criteria and calculated failure pressures (§192.620(d)(11)).

6 HIGH YIELD PIPELINES (GENERALLY GRADE X-70 OR ABOVE)

(a) Operators should perform ILI that will identify threats to the pipeline.
   (1) The operator should use a high-resolution deformation tool in lieu of a geometry tool.
   (2) The deformation tool is to include multi-finger sensors and have an accuracy of +/- 1 percent to identify expanded pipe and dents.

(b) The results of the initial ILI must be integrated with the initial CIS and any DCVG or ACVG surveys required by §192.620, as well as other data, such as patrolling and depth-of-cover surveys (§192.620(d)(7)(iii)).

(c) The operator must evaluate and remediate anomalies (e.g., expanded pipe, dents) prior to increasing the pressure above 72 percent SMYS for Class 1 locations (see §192.620(c)(2)(ii) and (c)(5))
   (1) The results of deformation and geometry tool runs for expanded pipe and dents should be analyzed and submitted to the PHMSA Regional Director.
   (2) All pipe exhibiting an indicated diameter greater than 1 percent above the nominal pipe diameter should be noted on the report of potential deformations.
   (3) Analysis should consider pipe properties and property distributions, hydrostatic test pressures and reported test behavior, and pipe end-to-center variations. Based on local pressure and expected behavior, any expansion exceeding anticipated expansion by more than 1.5 percent should be investigated by excavation to determine actual expansion.
   (4) An operator should take appropriate action in accordance with OPS Advisory Bulletin ADB-10-03 for examination of potential problems with misalignment, improper transitioning, improper back welds, cut factory bends, improper support of pipe and appurtenances, and other construction issues.

7 DENT REPAIRS

Certain pipeline dents must be repaired in order to operate pipelines at stress levels allowed under the alternative MAOP rule as follows.

(a) The repair criteria in §192.620(d)(11)(ii) require that dents in existing lines implementing alternative MAOP must be repaired if they meet criteria in either §192.309(b) or §192.933(d)(1) or (2). This is
intended to ensure that existing pipelines operated at stress levels allowed by the alternative MAOP rule are in "like new" condition with respect to dent defects.

(b) The operator should review the deformation/geometry tool reports and consider the following information.
   (1) Pipe properties and property distributions from tests.
   (2) Test pressures and reported test behavior from hydrostatic tests.
   (3) Pipe end-to-center diameter variations.

(c) Inspections for low-strength pipe and any pipe repair/removal must be completed prior to operating the pipeline to an alternative MAOP (§192.620(c)(8)).

8 REFERENCES

(c) OPS Advisory Bulletin ADB-10-03 (75 FR 14243, Mar. 24, 2010; see Guide Material Appendix G-192-1, Section 2).

§192.621
Maximum allowable operating pressure: High-pressure distribution systems.
[Effective Date: 07/13/98]

(a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:
   (1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part.
   (2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i.g., unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of §192.197(c).
   (3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.
   (4) The pressure limits to which a joint could be subjected without the possibility of its parting.
   (5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.

(b) No person may operate a segment of pipeline to which paragraph (a) (5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

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

GUIDE MATERIAL

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

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 roles and responsibilities of the controller during normal, abnormal, and emergency operating conditions. This section also requires operators to define
the roles, responsibilities, and qualifications of others authorized to direct or supersede the actions of the controller.

(a) Normal operating conditions.
   (1) Types of normal operating conditions might include the following.
      (i) Gas flow control and monitoring.
      (ii) Gas pressure control and monitoring.
      (iii) Equipment operation and monitoring.
      (iv) System requirements and monitoring.
      (v) Start/stop of compressor stations to meet system requirements.
      (vi) Gas delivery schedule adjustments.
      (vii) Gas storage monitoring.
      (viii) Interconnects and delivery nominations.
      (ix) Pressure set-point adjustments.
      (x) Activation or deactivation of pipelines for routine operations.
      (xi) Pigging operations.
      (xii) Notifications to field personnel.
   (2) Procedures should contain the following.
      (i) A description of normal operating conditions.
      (ii) A clear definition of the controller’s authority over normal system operations. Consideration should be given to the responsibilities that could be within a controller’s range of authority, without requiring any supervisory oversight or approval.
      (iii) A communication protocol should designate who a controller should notify and what information the controller should provide during normal operational changes. This could be as simple as a log, or could rely on computerized records to note the changes. The communication protocol should define the required communications between the control room and field operations personnel.
      (iv) Recordkeeping requirements for controller shift changes.

(b) Abnormal operating conditions.
   (1) Types of abnormal operating conditions might include the following.
      (i) Loss of communication between the SCADA display and a field device.
      (ii) An operable field device that does not respond to a SCADA command.
      (iii) An unexpected shutdown of field equipment, such as a compressor engine.
      (iv) An unexpected closure of a valve.
      (v) Pressure exceeding MAOP or pressure limits.
      (vi) Pressure falling below delivery requirements.
      (vii) False or abnormal readings.
      (viii) High-high alarms.
      (ix) Activation of a safety device, such as a relief valve.
      (x) Emergencies on connecting pipelines.
      (xi) Any other malfunction of a component, deviation from normal operation, or personnel error which may result in a hazard to persons or property as defined by the operator.
      (xii) For transmission operators, events defined by the requirements of §192.605(c).
   (2) Procedures should contain the following.
      (i) A description of operations that would constitute an abnormal operating condition or situation.
      (ii) Actions that should be taken by a controller upon becoming aware of an abnormal operating condition.
      (iii) A definition of roles, responsibilities, and actions that a controller may take without supervisory approval. All actions should be to protect people first and then property.
      (iv) A communications protocol that designates, upon a controller becoming aware of an abnormal situation, who that controller should notify and what information should be provided. The protocol should include communication requirements for an abnormal situation discovered by the controller or by field personnel. Information regarding the
situation should be recorded and include the persons notified and the information provided.

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

(c) Emergency operating conditions.

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

(i) Overpressurization.

(ii) Low pressure.

(iii) Sudden pressure drop.

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

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

(vi) Weather-related events, such as flooding, tornado, or hurricane causing damage to a pipeline facility.

(vii) Hazardous leak.


(2) Procedures should contain the following.

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

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

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

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

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

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

3.3 Communications.

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

(a) Communication protocols.

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

(b) Control room shift change communication.

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

(c) Procedures should contain the following.

(1) A process to record shift changes between controllers, including names and times of changes. This can be a paper or electronic logbook, a SCADA system login, a checklist, or some other process.
(b) Post-emergency reviews, as required by §192.615(b)(3), should examine whether controller actions contributed to the emergency. In addition to emergencies and reportable incidents, an operator should review abnormal operations (§192.605(c)), accidents, failure investigations (§192.617), root-cause investigations, or near misses as these might also provide valuable information. Any deficiencies or improvements noted during the review should be documented, and changes to the procedures should be implemented, if appropriate.

(c) The review procedure should specify the records needed to provide documentation of the incident reviews.

6 MANAGEMENT OF CHANGE (§192.631(f))

(a) Changes are regular occurrences during the course of pipeline operations requiring effective management through established processes and procedures. Operators should identify and document any changes that might impact a controller’s ability to monitor or control the pipeline facilities. Communications between the control room, management, and field personnel are a vital part of the control room MOC process. Operators should consider controller involvement when implementing any of the following changes to pipeline facilities.

(1) Temporary interruption or limitation of gas flow (e.g., valve closure, pipeline shutdown).
(2) Restoration of gas flow capability (e.g., valve opening, completion of maintenance outage).
(3) Temporary limitation or restoration of control (e.g., compressor maintenance outage, regulator or city-gate station maintenance).
(4) Temporary or permanent change in pipeline flow patterns (e.g., placing new pipeline facility in service, removing a pipeline from service).
(5) Change in established MAOP due to regulatory oversight or integrity management limitation.
(6) Purchase or sale of assets.
(7) Change to existing equipment (e.g., valves, piping) or new equipment coming online.
(8) Newly constructed facility (e.g., pipeline, compressor station, measurement or regulator station) being turned on line.
(9) Procedural change affecting operations, maintenance, or safety.
(10) Change to operating agreement.
(11) Pigging or other maintenance activity.
(12) Change to control systems or SCADA.
(13) Emergency or abnormal situation.
(14) Implementation of change resulting from the required reviews in 5 above.

(b) Information about planned changes (e.g., temporary flow patterns, new facilities, blow-down activities) to a controlled pipeline facility should be brought to the attention of the controller through direct planning involvement.

(c) An MOC plan for a control room may be a separate document, or an existing MOC process may be modified to address the requirements of a control room. An operator is encouraged to consolidate procedures, where possible, to reduce the number of potential conflicts between multiple documents.

7 TRAINING (§192.631(h))

The controller training program may include the following.

(a) Appropriate training for activities that would be considered covered tasks in the operator qualification (OQ) program.

(1) An operator should continue to implement the OQ regulations (Subpart N) through the application of the four-part test for covered tasks. The operator should also determine whether any new tasks will be added to the OQ program when implementing control room management procedures. The operator should define both generic and specific covered tasks for controllers.
(2) Certain control room procedures that are developed should be incorporated into the OQ program, as appropriate.

b) Training content that is specific to controller roles and responsibilities.

(1) A working knowledge of the pipeline system, including the following.
   (i) Practical knowledge of how fluid dynamics, electrical power, and communications could impact operations (for communications, see 3.3 above).
   (ii) Information about how pressure and flow in all pipeline segments are impacted by control actions.
   (iii) Information about flexibility and limitations at inlet points, mainline valves, stations, and delivery points.
   (iv) MAOP and any imposed lower pressures on all pipeline segments within the controller’s area of responsibilities.

(2) All reasonably foreseeable operational configurations (setups) in its training program, including those setups that are repeated on an infrequent basis (possibly quarterly or greater intervals). Examples of infrequent operations include the following.
   (i) Seasonal operating parameters.
   (ii) Start-up and shutdown.
   (iii) Line reversals.
   (iv) Combining pipelines (through valve operation) to operate in common rather than separately.
   (v) Bleed valve operations.
   (vi) Power-loss failure modes.
   (vii) Slack line conditions.
   (viii) Purging.
   (ix) Running in-line inspection tools.

(3) A list of foreseeable operating scenarios that is more likely to cause an AOC, simultaneous AOCs, or multiple AOCs in sequence for training controllers on how to recognize and handle them. Section 192.631(h)(2) requires that the training program for AOCs include either tabletop exercises or computerized simulation methods.

(4) A review of historical alarm logs to identify appropriate scenarios for training.

(5) Accidents, incidents, near misses, non-reportable events (e.g., small leaks, audit findings), and circumstances that could better inform and better train controllers to safely control the pipeline and recognize and correctly respond to abnormal, unusual, or emergency conditions as defined in 5 above. Events in which controllers contributed to the event are important to avoid recurrence of controller mistakes. Also, proper controller reaction is an important aspect in avoiding recurrence of other types of incidents.

(6) Lessons learned from field equipment deficiencies that could affect control room operations. The following are some examples.
   (i) Instrumentation that is out of calibration, resulting in a false alarm or inaccurate display of operational parameters (e.g., pressure, flow).
   (ii) Valve limit switches that provide incorrect information on valve status.
   (iii) Inappropriate setting for relief equipment compared to alarm set points.
   (iv) Discovery of a mainline valve previously unknown to the controller.

(7) The responsibilities for communication, including the operator’s communications plan and emergency plan requirements.

(c) Provisions for recordkeeping to demonstrate that each controller has successfully completed the controller operator qualification and training program, including requalification (§192.631(jj)(1)). Records should include the following.

(1) Controller name and training date.

(2) Course materials, including descriptions of exercises and simulations employed during the training.

(3) Tests and results.
(d) Training and exercises that include controllers and other individuals, defined by the operator, who would operationally collaborate with control room personnel during normal, abnormal, or emergency situations (§192.631(h)(6)).
(e) An operator’s control room management procedures must include provisions for training program review each calendar year, but at intervals not exceeding 15 months between reviews (§192.631(h)).

8 SHIFT WORK AND FATIGUE (§192.631(d))

Many control rooms are 24-hour operations, staffed by controllers that work in shifts. Shift work or long hours can result in controller fatigue. Control room management procedures should address staffing requirements to maintain the safe operation of the pipeline. Written procedures must establish a maximum controller service-hour limit and should take into consideration the unique factors of the operator’s system. Deviation from the limits may occur during emergencies, but should only be permitted as necessary for the safe operation of the pipeline. Deviations from service-hour limits must be documented (§192.631(j)(2)). Operators are required to provide education and training to controllers and appropriate supervisory personnel on fatigue awareness and fatigue mitigation.

8.1 Shift scheduling.
(a) Shift length and schedule rotations must allow controllers opportunity for eight hours of continuous sleep (§192.631(d)(1)). In addition, operators are also required to establish the maximum hours of service for controllers. Considerations in developing and managing shift schedules should include the following.
   (1) Number of available controllers.
   (2) Length of each shift.
   (3) Minimizing the disruption of normal sleep patterns.
   (4) Overlap time, if any, between shifts.
   (5) Time off between shifts (e.g., 8-hour shifts have 16 hours of “off” time, 10-hour shifts have 14 hours of “off” time, 12-hour shifts have 12 hours of “off” time).
   (6) Controller travel time between home and control room.
   (7) Rotation and time off between shift changes (e.g., day shift to night shift and night shift to day shift).
   (8) Coverage in the event of unexpected controller absence.
   (9) Single controller shifts.
   (10) Overtime scheduling and limitations on “double” shifts.
   (11) Controllers that also perform other non-control room functions.
(b) Operators should develop procedures to provide and document control room coverage during an emergency situation that would result in a controller’s maximum hours of service being exceeded. Deviations from normal shifts must be documented (§192.631(j)(2)).
(c) Operators are required to demonstrate compliance with their established shift lengths and schedule rotations (§192.631(d)(1) and (j)(1)). An operator should also consider the time controllers spend performing non-controller activities and commuting. Methods of accurately recording hours of service might include the following.
   (1) Time cards.
   (2) Shift-change records.
   (3) Keycards.
   (4) Any other method that can reasonably demonstrate controller hours of service.

8.2 Fatigue awareness.
Fatigue awareness training may be included in the OQ plan or in a separate plan. Fatigue awareness and mitigation training should include educating controllers and their supervisors on the following subjects.
(a) Fatigue.
   (1) Definition.
(2) Signs and symptoms.
(3) Causes.
(4) Effects on the human body.
(5) Use of stimulants, such as caffeine.
(6) Relation to physical activity and nutrition.
(7) Accumulation.
(8) Driving.
(9) Countermeasures.
(10) Relation to off-duty activities.

(b) Sleep.
(1) Circadian rhythms (i.e., body clock)
(2) Importance of sufficient sleep.
(3) Physiological effects of inadequate sleep.
(4) Psychological effects of inadequate sleep.
(5) Sleep environment.
(6) Causes of sleep deprivation.
(7) Sleep disorders.
(8) Medication effects.

8.3 Fatigue mitigation.
(a) An operator should implement means designed to mitigate on-duty controller fatigue and procedures for addressing when a controller has been identified as fatigued. Operators that use a single controller should develop a method to allow controllers to reduce fatigue and still be aware of changes or alarms that might occur while away from their console or desk.
(1) Methods to reduce fatigue in a controller’s work environment may include the following.
   (i) Adjusting control room environmental factors (e.g., lighting, temperature, sound).
   (ii) Strategic use of break periods.
   (iii) Varying tasks during shifts.
   (iv) Making exercise time or equipment available.
(2) An adequate recovery period in the form of “off” time should be provided to controllers when changing shift cycles from night-to-day or day-to-night.
(3) Fatigue identification procedures should include the following.
   (i) A method to notify appropriate supervision.
   (ii) A means or plan to replace or substitute a controller that has been identified as fatigued.
(b) An operator might consider providing a sleep area or transporting a fatigued controller home to prevent that controller from driving.

9 COMPLIANCE AND DEVIATION

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

10 REFERENCES

(a) API RP 1165, “Recommended Practice for Pipeline SCADA Displays” (see §192.7 for IBR).
(b) API RP 1168, “Pipeline Control Room Management.”
SUBPART M
MAINTENANCE

§192.701
Scope.

[Effective Date: 11/12/70]

This subpart prescribes minimum requirements for maintenance of pipeline facilities.

GUIDE MATERIAL
No guide material necessary.

§192.703
General.

[Effective Date: 11/12/70]

(a) No person may operate a segment of pipeline, unless it is maintained in accordance with this subpart.
(b) Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.
(c) Hazardous leaks must be repaired promptly.

GUIDE MATERIAL

1 GENERAL

Any time a pipeline is found to be damaged or deteriorated to the extent that its serviceability is impaired or leakage constituting a hazard is evident, immediate temporary measures should be employed to protect the public and property. If it is not feasible to make a permanent repair at the time of discovery, permanent repairs should be made as soon as feasible.

2 REPAIR OF PIPE

2.1 General.
Prior to repairing a pipeline, the operator should consider the operating conditions, design, and maintenance history, as necessary, to ensure that repair actions do not further damage the pipe. Where warranted, the operating pressure should be lowered, pipe exposure should be limited, access to the area should be limited, personnel protection should be provided, and fire extinguishing equipment should be available.

2.2 Repairs to distribution lines.
Methods of permanent repair to non-thermoplastic distribution lines include the following.
(a) Cutting out as a cylinder and replacing the piece of damaged pipe.
(b) Applying a full-encirclement welded split sleeve of appropriate design.
(c) Applying a properly designed bolt-on type of leak clamp or sleeve.
(d) For steel pipe, applying a fillet-welded steel plate patch of similar material of equal or greater thickness, of appropriate grade, and with rounded corners.

2.3 Repairs to transmission lines.
For repairs to steel transmission lines, see §§192.711, 192.713, 192.715, 192.717, and 192.751. Section 192.485 allows the alternative of lowering the MAOP on corroded transmission pipe where a safe operating pressure can be calculated based on the remaining strength of the corroded pipe. See guide material under §192.485.

2.4 Permanent repairs to thermoplastic piping.
Repair methods for thermoplastic piping include the following.
(a) Cutting out as a cylinder and replacing the piece of damaged pipe.
(b) Applying a properly designed bolt-on type saddle, leak clamp, or sleeve.
(c) Installing a repair sleeve meeting the requirements of ASTM D2513 (see §192.7).
(d) See guide material under §192.311.
(e) For gas flow control during repair (e.g., squeeze-off and re-opening), see 5 of the guide material under §192.321.

2.5 Repair procedures.
The repair should be made in accordance with a qualified repair procedure.

2.6 Compression couplings in pipelines.
Repairs using compression couplings and repairs to pipelines that may contain compression couplings should consider the following.
(a) Coupled pipe is subject to pullout near bends, near the end of the pipeline, at temporary end closures, while performing stoppering or stopping procedures, when the pipeline is severed, and while long sections of pipeline are exposed.
(b) Some factors that can contribute to pullout potential are the pipe diameter, material, and surface; operating pressure; temperature changes; buoyancy; and soil moisture, compaction, and type.
(c) The procedure for safely repairing the pipeline should include consideration of the following precautionary, preventive, and mitigating actions.
(1) Reviewing maps and records to determine if couplings exist.
(2) Reviewing and following manufacturer's recommendation for installing and maintaining compression couplings.
(3) Analyzing each project for the potential of coupling pullout, including pullouts on adjacent line sections.
(4) Performing an electrical continuity test to check for indications of unknown insulating couplings.
(5) Reviewing contingency procedures to be used in the event of a pullout.
(6) Reducing pressure prior to excavation.
(7) Installing anchors sufficient to resist anticipated pullout forces caused by movement of the pipeline in any direction.
(8) Reinforcing known couplings.
(9) Minimizing the length of exposed pipe during the repair work.
(10) Backfilling offset replacement piping before severing the pipeline.
(11) Providing a separate excavation for pressure control operations to prevent injury from pullout of an unknown coupling.
(12) Designing and installing protective sleeves or bridging when making mechanical joints that either connect plastic piping or plastic piping to steel piping. This is especially true for PE pipe manufactured prior to 1982, since some is known to be susceptible to premature brittle-like failures. Also, attention should be given to any recommendations by the pipe manufacturer. For protective sleeves, see guide material under §192.367.
§192.711
Transmission lines: General requirements for repair procedures.
[Effective Date: 10/01/10]

(a) **Temporary repairs.** Each operator must take immediate temporary measures to protect the public whenever:
   (1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and
   (2) It is not feasible to make a permanent repair at the time of discovery.

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

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


GUIDE MATERIAL

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

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

§192.713
Transmission lines: Permanent field repair of imperfections and damages.
[Effective Date: 01/13/00]

(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be —
   (1) Removed by cutting out and replacing a cylindrical piece of pipe; or
   (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

(b) Operating pressure must be at a safe level during repair operations.

1 GENERAL

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

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

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

2 REPLACEMENT (§192.713(a)(1))

   (a) The operator should consider the possibility that some degree of impairment may have occurred beyond the area of immediate concern. The impairment may be due to a defect in the longitudinal weld, external or internal corrosion, or damage by excavating equipment at another location when excavation work covers a large area. The pipe on each side of the known impairment should be examined to determine the extent of the replacement.
   (b) Operators should consider the following potential concerns when repairing a segment of transmission line by replacing pipe.
      (1) Passage of internal inspection devices (see §192.150) when replacing a segment of transmission line with pipe of a heavier wall thickness.
      (2) Welding when replacing a segment of transmission line with pipe of a heavier wall thickness or of a greater strength steel.

3 REPAIR (§192.713(a)(2))

3.1 General.
   (a) The use of an appropriately designed full-encirclement split sleeve is recognized as an acceptable repair method. Other methods, including the use of composite-reinforced sleeve material, may also be available. However, operators are cautioned that not all repair methods are suitable for permanent repair of leaking or through-wall defects. Review the manufacturer's installation requirements before deciding to use a composite sleeve to make permanent repair. The repair method selected should:
      (1) Have or achieve a strength at least equal to that required for the MAOP of the pipe being repaired, and
      (2) Be capable of withstanding the anticipated circumferential and longitudinal stresses, including additional stress due to external loading.
   (b) In determining the length of the repair, the operator should consider that:
      (1) Some degree of impairment might have occurred beyond the area of immediate concern (see 2 above), and
      (2) Full-encirclement sleeves should not be less than 4 inches in length.
   (c) A wide variety of repair methods has been used successfully in the natural gas pipeline industry. Sleeves may be used to reduce the stress in, or reinforce, a pipe defect that is not leaking, or to repair a leaking defect. It is important that any repair method or sleeve be carefully designed and tested to ensure its reliability for the conditions of installation.
§192.740
Pressure regulating, limiting and overpressure protection – Individual service lines directly connected to production, gathering, or transmission pipelines.

(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.

[Amtd. 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.

(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.
### 1.5 FITTINGS: THREADED & SOCKET-WELD (Continued)

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### 1.7 MATERIALS & FITTINGS: MISCELLANEOUS

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<td>Forged or Rolled Alloy and Stainless Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service</td>
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<td>ASTM A234</td>
<td>Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and High Temperature Service</td>
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<td>ASTM A350</td>
<td>Carbon and Low-Alloy Steel Forgings, Requiring Notch Toughness Testing for Piping Components</td>
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<td>Wrought Austenitic Stainless Steel Piping Fittings</td>
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<td>ASTM A420</td>
<td>Piping Fittings of Wrought Carbon Steel and Alloy Steel for Low-Temperature Service</td>
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<td>AWWA C111 / ANSI 21.11</td>
<td>Rubber-Gasket Joints for Ductile-Iron Pressure Pipe and Fittings</td>
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<td>AWWA Manual M41</td>
<td>Ductile-Iron Pipe and Fittings</td>
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<tr>
<td>MSS SP-6</td>
<td>Standard Finishes for Contact Faces of Pipe Flanges and Connecting-End Flanges of Valves and Fittings</td>
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<td>AGA CPR-83-4-1</td>
<td>Threaded Fasteners Torquing (Available on GPTC website under Reports and Position Papers)</td>
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<td>Unified Inch Screw Threads (UN and UNR Thread Form)</td>
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<td>Non-metallic Flat Gaskets for Pipe Flanges</td>
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<td>Square, Hex, Heavy Hex, and Askew Head Bolts and Hex, Heavy Hex, Hex Flange, Lobed Head, and Lag Screws (Inch Series)</td>
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<td>Nuts for General Applications: Machine Screw Nuts, Hex, Square, Hex Flange, and Coupling Nuts (Inch Series)</td>
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<td>ASTM A193</td>
<td>Alloy-Steel and Stainless Steel Bolting for High-Temperature or High Pressure Service and Other Special Purpose Applications</td>
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<td>ASTM A194</td>
<td>Carbon, Alloy Steel, and Stainless Steel Nuts for Bolts for High-Pressure or High-Temperature Service, or Both</td>
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<td>ASTM A307</td>
<td>Carbon Steel Bolts, Studs, and Threaded Rod 60,000 PSI Tensile Strength</td>
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<td>Alloy-Steel and Stainless Steel Bolting for Low-Temperature Service</td>
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<td>Quenched and Tempered Alloy Steel Bolts, Studs, and Other Externally Threaded Fasteners</td>
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<td>Hex Cap Screws, Bolts and Studs, Steel, Heat Treated, 120/105/90 ksi Minimum Tensile Strength, General Use</td>
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### 1.9 CORROSION RELATED

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<tr>
<td>ASME STP-PT-011</td>
<td>Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas</td>
<td>§192.613  §192.929</td>
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<td>CEPA</td>
<td>Stress Corrosion Cracking Recommended Practices, 2nd Ed</td>
<td>§192.929</td>
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<tr>
<td>GTI-04/0071</td>
<td>External Corrosion Direct Assessment (ECDA) Implementation Protocol</td>
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<td>NACE MR0175</td>
<td>Materials for Use in H₂S-Containing Environments in Oil and Gas Production</td>
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<td>ASTM D2657</td>
<td>Heat Fusion Joining of Polyolefin Pipe and Fittings</td>
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<tr>
<td>ASTM D2837</td>
<td>Standard Test Method for Obtaining Hydrostatic Design Basis for Thermoplastic Pipe Materials or Pressure Design Basis for Thermoplastic Pipe Products</td>
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<td>Two-Step (Primer and Solvent Cement) Method of Joining Poly (Vinyl Chloride) (PVC) or Chlorinated Poly (Vinyl Chloride) (CPVC) Pipe and Piping Components with Tapered Sockets</td>
<td>§192.281</td>
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<td>ASTM F689</td>
<td>Determination of the Temperature of Above-Ground Plastic Gas Pressure Pipe Within Metallic Casings (Withdrawn 2017)</td>
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<td>ASTM F1041</td>
<td>Guide for Squeeze-Off of Polyolefin Gas Pressure Pipe and Tubing</td>
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<td>ASTM F1290</td>
<td>Electrofusion Joining Polyolefin Pipe and Fittings</td>
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<td>ASTM F1563</td>
<td>Tools to Squeeze-Off Polyethylene (PE) Gas Pipe or Tubing</td>
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<tr>
<td>ASTM F1804</td>
<td>Standard Practice for Determining Allowable Tensile Load for Polyethylene (PE) Gas Pipe During Pull-in Installation</td>
<td>GMA G-192-15B</td>
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<tr>
<td>ASTM F1924</td>
<td>Plastic Mechanical Fittings for Use on Outside Diameter Controlled Polyethylene Gas Distribution Pipe and Tubing</td>
<td>§192.123</td>
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<td>ASTM F1948</td>
<td>Metallic Mechanical Fittings for Use on Outside Diameter Controlled Thermoplastic Gas Distribution Pipe and Tubing</td>
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<tr>
<td>ASTM F1973</td>
<td>Factory Assembled Anodeless Risers and Transition Fittings in Polyethylene (PE) and Polyamide 11 (PA11) and Polyamide 12 (PA12) Fuel Gas Distribution Systems</td>
<td>§192.123</td>
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<td>GRI-92/0147.1</td>
<td>Users’ Guide on Squeeze-Off of Polyethylene Gas Pipes</td>
<td>§192.321</td>
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<td>GRI-96/0194</td>
<td>Service Effects of Hydrocarbons on Fusion and Mechanical Performance of Polyethylene Gas Distribution Piping</td>
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<tr>
<td>PPI - Handbook of PE Pipe</td>
<td><strong>Note:</strong> The following are available as individual chapters of the PPI Handbook of Polyethylene Pipe:</td>
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<td></td>
<td>Chapter 8 – Above-Ground Applications for Polyethylene Pipe</td>
<td>§192.321</td>
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<td>PPI TN-13</td>
<td>General Guidelines for Butt, Saddle and Socket Fusion of Unlike Polyethylene Pipes and Fittings</td>
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<td>Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe</td>
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<td>API RP 520 P2</td>
<td>Sizing, Selection and Installation of Pressure-Relieving Devices in Refineries, Part 2 Installation</td>
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<td>API RP 525</td>
<td>Testing Procedure for Pressure-Relieving Devices Discharging Against Variable Back Pressure (Revised 1960; Discontinued)</td>
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<td>Test Method for Performance Testing of Excess Flow Valves</td>
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<td>Excess Flow Valves, NPS 1 1/4 and smaller, for Fuel Gas Service</td>
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<td>NBBI</td>
<td>Relieving Capacities of Safety Valves and Relief Valves Approved by the National Board (Discontinued)</td>
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<td>Pipe Hangers and Supports - Materials, Design, Manufacture, Selection, Application, and Installation</td>
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<td>OPS ADB-12-02</td>
<td>Advisory Bulletin – Post-Accident Drug and Alcohol Testing (77 FR 10666, Feb. 23, 2012)</td>
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<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>
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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>
<td>§192.615</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>
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<td>OPS ALN-89-01</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>
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<td>Technical Task Order – Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation, Michael Baker Jr., Inc., et al</td>
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<td>Technical Task Order – Stress Corrosion Cracking Study, Michael Baker, Jr., Inc., January 2005</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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<tr>
<td>&quot;Evaluation of Chemical Treatments in Natural Gas System vs. MIC and Other Forms of Internal Corrosion Using Carbon Steel Coupons,&quot; Timothy Zintel, Derek Kostuck, and Bruce Cookingham, Paper # 03574 presented at CORROSION/03 San Diego, CA</td>
<td>§192.475</td>
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<tr>
<td>&quot;Field Use Proves Program for Managing Internal Corrosion in Wet-Gas Systems,&quot; Richard Eckert and Bruce Cookingham, Oil &amp; Gas Journal, January 21, 2002</td>
<td>§192.475</td>
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<tr>
<td>&quot;Internal Corrosion Direct Assessment,&quot; Oliver Moghissi, Bruce Cookingham, Lee Norris, and Phil Dusek, Paper # 02087 presented at CORROSION/02 Denver, CO</td>
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<tr>
<td>&quot;Internal Corrosion Direct Assessment of Gas Transmission Pipeline – Application,&quot; Oliver Moghissi, Laurie Perry, Bruce Cookingham, and Narasi Sridhar, Paper # 03204 presented at CORROSION/03 San Diego, CA</td>
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<tr>
<td>Plastic Pipe Database Committee (PPDC) reports, <a href="http://www.aga.org/Kc/OperationsEngineering/ppdc%3EStatus%20Reports/Pages/default.aspx">www.aga.org/Kc/OperationsEngineering/ppdc&gt;Status%20Reports/Pages/default.aspx</a></td>
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### 3.4 UNCASED PIPE AND DIRECTIONAL DRILLING RELATED

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<tr>
<td>&quot;Considerations for the Installation of Polyethylene Water Pipe by ‘Horizontal Directional Drilling,’ Larry Petroff, Performance Pipe, presented at Annual Conference and Exposition of AWWA, 2006</td>
<td>GMA G-192-15B</td>
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<tr>
<td>&quot;Guidelines For A Successful Directional Crossing Bid Package,&quot; Directional Crossing Contractors Association, 1995</td>
<td>GMA G-192-15A</td>
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### 3.5 SAFETY AND INTEGRITY MANAGEMENT RELATED

<table>
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<th>Citation</th>
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<tbody>
<tr>
<td>&quot;Guideline for Assessing the Performance of Oil and Natural Gas Pipeline Systems in Natural Hazard and Human Threat Events,&quot; American Lifelines Alliance.</td>
<td>§192.917</td>
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</table>
1 INTRODUCTION

1.1 Scope.
(a) This guide material is intended to assist operators with development of a Distribution Integrity Management Program (DIMP), including the written plan, and compliance with Federal Regulations §§192.1001, 192.1003, 192.1005, 192.1007, 192.1009, 192.1011, and 192.1015 on DIMP. It provides operators with practices that may be considered as they develop and maintain a DIMP specific to their gas distribution systems.
(b) Distribution pipeline systems and associated operating practices can vary widely. Examples of system differences include: materials used, age, manner of construction, operation and maintenance practices, and operating environments (natural and man-made). This guidance recognizes that there is wide diversity among distribution systems and is therefore flexible, allowing operators to identify considerations dealing with their unique threats and to select actions suited to their specific needs.
(c) The options in this guidance are intended to provide the operator with a selection of possible choices to use in improving the integrity of its distribution system. Operators may not need to consider or perform every step presented. It is not intended that an operator evaluate every option or provide justification or reasons why options were not implemented.
(d) Section 192.1003 exempts individual service lines directly connected to a transmission, gathering, or production pipeline. Most of these types of service lines are commonly known as “farm taps”. Such service lines are excluded from the DIMP requirements.
(e) Section 192.1015 imposes different requirements for small liquefied petroleum gas (LPG) operators (i.e., those serving fewer than 100 customers from a single source) and master meter operators. Since these pipeline systems are less complex, the integrity management requirements are simplified. The appropriate portions of this guide material are valid for those operators. PHMSA-OPS has published “Guidance for Master Meter and Small Liquefied Petroleum Gas Pipeline Operators” to assist operators of these systems to implement requirements of the DIMP rule, which can be found at: primis.phmsa.dot.gov/dimp/docs/GuidanceForMasterMeterAndSmallLiquefiedPetroleumGasPipelineOperators_11_09.pdf.

1.2 Glossary of Abbreviations.

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<th>Abbreviation</th>
<th>Meaning</th>
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<td>A/A</td>
<td>additional or accelerated (actions)</td>
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<td>CP</td>
<td>cathodic protection</td>
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<tr>
<td>DIMP</td>
<td>Distribution Integrity Management Program</td>
</tr>
<tr>
<td>LPG</td>
<td>liquefied petroleum gas</td>
</tr>
<tr>
<td>PE</td>
<td>polyethylene</td>
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<tr>
<td>SCADA</td>
<td>supervisory control and data acquisition</td>
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<td>SDR</td>
<td>standard dimension ratio</td>
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<td>SME</td>
<td>subject matter expert</td>
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1.3 How to use this guide material.
The guide material is organized to coincide with the seven required elements of a DIMP. The order in which the guidance is presented does not imply the order in which it should be applied. However, the operator needs to address each element in some way. Once an operator determines how it can best accomplish distribution system integrity, the guide material may be used to support or direct the operator’s approach. The operator is cautioned that the guide material may not anticipate all conditions that may be encountered, and the operator is not restricted from using other methods to comply with the Regulations.

Two sample DIMP approaches are given in Section 11.
1.4 **Overview.**

(a) The objective of a DIMP is to manage the integrity of a gas distribution system. As discussed in detail in Section 5, an essential part of a DIMP is a risk evaluation of the distribution system. One approach to risk evaluation is to group facilities by common traits or problems, and then perform a risk ranking. This process allows the grouping of facilities that experience similar threats to be risk-ranked together. Then, if necessary, attention can be focused on developing measures that address the greatest risks.

(b) After identifying the problems, the operator should consider the concept of grouping facilities when first developing its DIMP. Such groupings could significantly affect how the operator assembles data about its system (see Section 3) and how it approaches its threat analysis (see Section 4).

(c) The operator should also recognize that the development of the DIMP may be an iterative (or repeating) process. That means each time a cycle (e.g., gather knowledge, identify threats, rank risks, take action to reduce risk, measure performance) is completed, areas needing additional data, analyses, or actions may become apparent. For example, the initial general knowledge of the system may be used to group facilities, identify the applicable threats, and begin the risk analysis. In attempting to complete the risk analysis, the operator may determine the need for additional information. The operator may also determine that the facility groupings need to be redefined, such as by subdividing groups or combining groups.

2 **ELEMENTS OF A DISTRIBUTION INTEGRITY MANAGEMENT PLAN**

2.1 **General.**

Seven elements have been identified as the essential components of a DIMP, except as modified for those operators identified in §192.1015(a). Collectively, these elements establish a program that should reasonably manage the integrity of distribution pipeline systems on a going-forward basis. These elements are as follows.

(a) Knowledge (see Section 3).

(b) Identify threats (see Section 4).

(c) Evaluate and rank risk (see Section 5).

(d) Identify and implement measures to address risks (see Section 6).

(e) Measure performance, monitor results, and evaluate effectiveness (see Section 7).

(f) Periodic evaluation and improvement (see Section 8).

(g) Report results, except for master meter and small LPG operators (see Section 9).

2.2 **Develop and implement a written plan.**

Federal Regulations require that each distribution operator prepare and implement a written plan as a primary component of its DIMP. The function of the plan is to document how each of the applicable seven elements will be addressed and implemented. The plan should be complete and address required elements by the implementation dates in §§192.1005 and 192.1015. The plan should be concise, but still be sufficient for operator personnel to understand and implement the program on a consistent basis, and is not intended to include extensive technical justifications or detailed process descriptions.

3 **KNOWLEDGE**

3.1 **General.**

(a) Information, such as the materials and type of construction, the operating conditions of the pipe or facility, and other relevant factors within the surroundings in which the system operates, is referred to as the "knowledge of the distribution system."
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FORM FOR PROPOSALS ON ANSI GPTC Z380.1
(Revised July 2019)

Name ____________________________________________________________

Company _________________________________________________________

Address __________________________________________________________

Tel. No. _____________________________ Email: ________________________

Organization represented (if any) _______________________________________

1. Section/Paragraph ________________________________________________

2. Proposal recommends: □ new text
   (Check all that apply) □ revised text
   □ deleted text

3. Proposal (include proposed new or revised wording, or identification of wording to be deleted, use separate sheet if needed):
   [Proposed text should be in legislative format; i.e., use underscore to denote wording to be inserted (inserted wording) and strike-through to denote wording to be deleted (deleted wording)].

4. Statement of problem and substantiation for proposal (use separate sheet if needed): (State the problem that will be resolved by your recommendation; give the specific reason for your proposal including relevant support, such as copies of tests, research papers.)

5. □ This proposal is original material. (Note: Original material is considered to be the submitter’s own idea based on or as a result of his/her own experience, thought or research and, to the best of his/her knowledge, is not copied from another source.)
   □ This proposal is not original material; its source (if known) is as follows:

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