September 20, 2017

Dear Guide Purchaser,


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

Sincerely,

Secretary
GPTC Z380
The changes in this addendum are marked by wide vertical lines inserted to the left of modified text, overwriting the left border of most tables, or a block symbol (▌) where needed. There were no Federal Regulation updates for this period. Six GPTC transactions affected 11 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 5 sections of the Guide (plus other sections impacted by page adjustments, etc.).

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

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Guide for Gas Transmission, Distribution, and Gathering Piping Systems

2015 Edition
Addendum 8, August 2017
An American National Standard

Author:
Gas Piping Technology Committee (GPTC) Z380
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American National Standards Institute (ANSI)
August 24, 2017

Secretariat:
American Gas Association

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

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Parashar Sheth, National Grid

Committee Scope

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

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

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Addendum 8, August 2017
# GAS PIPING TECHNOLOGY COMMITTEE: Listed by Member Participation (Continued)

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**Addendum 8, August 2017**
## Abbreviations:
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First Vice Chairperson: 1st V Chair  
Second Vice Chairperson: 2nd V Chair  
Secretary: Sec  
Damage Prevention - Emergency Response: DP/ER  
Operations and Maintenance - Operator Qualification: O&M/OQ

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

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- Damage Prevention - Emergency Response: DP/ER
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Addendum 8, August 2017
## Abbreviations:
- Chairperson: Chair
- First Vice Chairperson: 1st V Chair
- Second Vice Chairperson: 2nd V Chair
- Secretary: Sec
- Damage Prevention - Emergency Response: DP/ER
- Operations and Maintenance - Operator Qualification: O&M/Q

## 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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| Pioli, Christopher A. | X | X | X | | | | | |
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| Quezada, Leticia | Chair | | | | | | | | | |
| Southern Company Gas, Naperville, IL | | | | |

| Ratcliffe, Alice | X | X | X | X | X | | | | Chair | |
| Crestwood Midstream, Fort Worth, TX | | | | |

| Rayot, Charles | X | X | X | | | | | |
| Ameren, IL, Pawnee, IL | | | | |

| Reynolds, Donald Lee | 1st V Chair | | | | | | | | Chair |
| NiSource Gas Distribution, Columbus, OH | | | | |

| Schmidt, Robert A. | X | X | X | | | | | |
| Canadoil Forge, Russellville, AR | | | | |
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EDITORIAL NOTES FOR THE HISTORICAL RECONSTRUCTION OF PARTS 191 AND 192

Part 191 became effective on February 9, 1970. Part 192 became effective on November 12, 1970. Subsequent amendments have been issued with some adding new sections and some amending pre-existing sections.

To aid the user in reconstructing the history of a particular section, the user is advised that the complete text of Parts 191 and 192 as originally issued, plus all amendments through Amdts. 191-15 and 192-93, are contained in AGA X69804, "Historical Collection of Natural Gas Pipeline Safety Regulations." Otherwise, refer to the Federal Register website for amendments.

Additionally, to aid the user, the following tabulations of amendments are provided.

HISTORICAL RECONSTRUCTION OF PART 191

(Complete through Amdt. 191-25)

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Reserved
moisture absorption and high electrical resistance.

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

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

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

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

GUIDE MATERIAL

1 REFERENCES

References are contained in Table 192.461i.

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1 For document titles, see Guide Material Appendix G-192-1, Section 1.9.

TABLE 192.461i

2 BORING OR DRIVING (§192.461(e))

See 2 of the guide material under §192.361.

§192.463
External corrosion control: Cathodic protection.

[Effective Date: 08/01/71]

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

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

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

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.
(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe.

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

GUIDE MATERIAL

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

§192.465 External corrosion control: Monitoring.

[Effective Date: 10/01/10]

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

(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2½ months, to ensure that it is operating.

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

(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.

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

3 DETECTION METHODS

The following may be used to detect internal corrosion.
(a) Visual inspection of piping and components.
   (1) Access ports.
   (2) Selective cut-outs.
(b) Corrosion monitoring devices.
   (1) Corrosion coupons and spools.
   (2) Resistance probes.
   (3) Polarization probes.
   (4) Hydrogen probes and patches.
   (5) Electrochemical probes.
(c) Sampling.
   (1) Liquids analysis.
      (i) Chemical composition.
      (ii) Microbiological composition.
   (2) Gas composition analysis.
   (3) Solids analysis.
      (i) Chemical composition.
      (ii) Microbiological composition.
(d) Trending of analytical data.
(e) Internal inspection tools.
(f) Ultrasonic inspection.
(g) Radiography.
(h) Failure analysis.
(i) Internal corrosion direct assessment.

4 FREQUENCY

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

5 MITIGATIVE MEASURES

The following measures can be used to mitigate internal corrosion.
(a) Control of moisture level (e.g., by dehydration, separation, or temperature control).
(b) Reduction of corrosive constituents (chemical or biological) in the gas.
(c) Internal coating.
(d) Liquids or solids removal.
   (1) Pigging - frequency of pigging will depend on both the volume and the analysis of materials received during pigging operations.
   (2) Drips - frequency of operation will depend on both the volume and analysis of materials removed.
   (3) Separators - frequency of maintenance will depend on changes in results from liquids analyses.
(e) Chemical or biological treatments.
   (1) Treatments should not cause deterioration of piping system components.
   (2) Treatments should be compatible with the following.
      (i) Gas being transported.
      (ii) Downstream gas utilization and processing equipment.
      (iii) Any other treatments.

6 REFERENCES

(a) See 2 of the guide material under §192.53.
(b) GRI-02/0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology."
(c) NACE MR0175, "Materials for Use in H₂S-Containing Environments in Oil and Gas Production."
(d) NACE RP0175, "Control of Internal Corrosion in Steel Pipelines and Piping Systems" (Revised 1975; Discontinued).
(e) NACE SP0192, "Monitoring Corrosion in Oil and Gas Production with Iron Counts."
(f) NACE SP0775, "Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations."
(g) NACE TM0194, "Field Monitoring of Bacterial Growth in Oilfield Systems."
(h) NACE 3D170, Technical Committee Report, "Electrical and Electrochemical Methods for Determining Corrosion Rates" (Revised 1984; Withdrawn 1994).
(i) "Evaluation of Chemical Treatments in Natural Gas System vs. MIC and Other Forms of Internal Corrosion Using Carbon Steel Coupons," Timothy Zintel, Derek Kostuck, and Bruce Cookingham, Paper # 03574 presented at CORROSION/03 San Diego, CA.
(k) "Field Use Proves Program for Managing Internal Corrosion in Wet-Gas Systems," Richard Eckert and Bruce Cookingham, Oil & Gas Journal, January 21, 2002.
(l) "Internal Corrosion Direct Assessment," Oliver Moghissi, Bruce Cookingham, Lee Norris, and Phil Dusek, Paper # 02087 presented at CORROSION/02 Denver, CO.
(m) "Internal Corrosion Direct Assessment of Gas Transmission Pipeline - Application," Oliver Moghissi, Laurie Perry, Bruce Cookingham, and Narasi Sridhar, Paper # 03204 presented at CORROSION/03 San Diego, CA.
7 OTHER CONSIDERATIONS

7.1 "Work authorization" programs.
Operators should consider including written procedures in their procedural manual for operations, maintenance, and emergencies to protect maintenance workers from the unexpected movement or release of energy when working on electrical, pressurized fluid, or mechanical systems where the inadvertent actuation or release of energy could be dangerous. The procedures commonly used to protect maintenance personnel include "lockout," "tagout," "blocking," and "work authorization" programs. Equipment that should be considered includes compressors, filters, scrubbers, launchers, heat exchangers, and powered valve actuators.

7.2 Operator's use of powered equipment.
Before using powered equipment for making an excavation, the operator should consider the following.
(a) The use of pertinent maps, other records, or other means to locate the operator's facilities.
(b) Verifying that all other operators of underground facilities in the area have been notified of the pending excavation and have responded by marking their facilities.
(c) Determining safe distances to be maintained between the digging end of the powered equipment and underground facilities.

7.3 Verification of established MAOP
(a) Operators should consider including written procedures in their manual for operations, maintenance, and emergencies that address the actions to be taken after records or materials are discovered that may call into question a pipeline's established MAOP. These written procedures should address the following, as applicable.
   (1) Date the pipeline segment became regulated as outlined in §192.13, and how to address unknown or newly discovered records, or record discrepancies.
   (2) Review of maintenance and construction activities subsequent to the original pressure test to verify that any repairs, relocations, or replacements meet the MAOP requirements and have the proper test and material documentation.
   (3) Discovery of a pressure test record used to establish the pipeline's current MAOP that has a lower test value, a shorter test duration, or other test record that does not meet the requirements for a valid pressure test as outlined in Subpart J.
   (4) Review of §§192.619, 192.621, 192.623 and 192.611 to determine if MAOP calculations are still valid.
   (5) Options to use field verification for a record indicating an unknown strength or rating, or a pressure rating less than the pipeline's established MAOP.
   (6) Consideration of an appropriate operating pressure reduction or restriction.
   (7) Coordination with operator's gas control personnel for planning potential operating pressure changes that could affect control room operations.
(b) If the MAOP verification indicates changes to MAOP are necessary, the operator should consider the following actions.
   (1) Assessing the impact to the pipeline system.
   (2) Identifying a remediation strategy for addressing deficiencies.
   (3) Revising the operator's pipeline records, which may include:
      (i) manual for operations, maintenance, and emergencies.
      (ii) gas control records.
      (iii) gas control alarms.
      (iv) GIS.
      (v) electronic databases.
      (vi) other records and documents where the operator may record pipeline MAOP data.
   (4) Communicating the change to the appropriate operator personnel.
   (5) Reviewing and revising overpressure protection requirements.
   (6) Identifying potential reporting requirements.
§192.607
(Removed and reserved.)
[Effective Date: 07/08/96]

§192.609
Change in class location: Required study.
[Effective Date: 11/12/70]

Whenever an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at hoop stress that is more than 40 percent of SMYS, or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine:

(a) The present class location for the segment involved.
(b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provisions of this part.
(c) The physical condition of the segment to the extent it can be ascertained from available records;
(d) The operating and maintenance history of the segment;
(e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and
(f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

GUIDE MATERIAL

No guide material necessary.
RESERVED
§192.611
Change in class location: Confirmation or revision of maximum allowable operating pressure.

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

1. If the segment involved has been previously tested in place for a period of not less than 8 hours:
   (i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.
   (ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

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

3. The segment involved must be tested in accordance with the applicable requirements of Subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:
   (i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.
   (ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.
   (iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

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

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

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a)(1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of
(c) SCC susceptibility.

There are a number of approaches for assessing and prioritizing pipeline susceptibility to SCC, and no single method is recommended over another. What is important is that a consistent approach be used that includes both technical and environmental factors that contribute to reducing the overall risk of a potential SCC occurrence. The following characterizations should be used to evaluate SCC susceptibility.

(1) Failure history - Identify past SCC failures.
(2) Coating type (e.g., coal-tar, tape) — Address condition and type of coating, including the type of surface preparation on the pipe prior to coating application.
(3) Pipe material (e.g., API grades, pipe mill).
(4) Operations (e.g., pressure, temperature).
(5) Location - Correlate the environmental conditions near the pipeline with the occurrence of SCC.
   (i) Use of soil models to correlate with potential coating disbondment segments.
   (ii) Drainage, local topography, soil disposition, and similar aspects of soil models, tied with time in service, are seen as predictors of potential coating failures.
(6) Age.
(7) Bellhole - Trending analysis of buried pipe inspection reports to identify common characteristics in pipe with SCC compared with pipe having no SCC.
(8) Magnetic flux leakage in-line inspection (ILI) results.
(9) Other ILI results.
(10) Cathodic protection level — Monitor CP voltage levels at locations with and without active SCC.
(11) Hydrostatic retest program – Testing pipe to determine presence of SCC.

*Note:* If critical size cracks are present, a rupture of the line will likely occur.

(d) Follow-up actions for positive indications of SCC susceptibility.

A written inspection, examination, and evaluation plan should be prepared when pipelines are determined to be susceptible to SCC.

(1) **Inspection.**

The inspection objectives are to conduct aboveground or other types of measurements to supplement, if needed, the data collected and analyzed to determine SCC susceptibility. This data should then be used to prioritize susceptible segments and to select the specific sites for direct examination. Inspection examples include the following.

   (i) Close-interval survey.
   (ii) Coating-fault survey.
   (iii) ILI geometry tool.
   (iv) ILI electromagnetic acoustical transducer (EMAT) tool.
   (v) Hydrostatic test.

(2) **Examination.**

Examination should include procedures to field-verify sites selected for direct examination. Any SCC detected should be followed by an assessment of its severity, extent, and type at the individual dig-site.

(3) **Evaluation.**

An operator's evaluation plan should address the following.

   (i) Method used to determine whether general SCC mitigation is required.
   (ii) Prioritize remedial action for defects that are not removed immediately.
   (iii) Evaluate the effectiveness of the SCC approach.

(e) **Mitigation.**

The necessity for and type of mitigation activity are typically dependent on the type of cracking present. Primary guidance for SCC mitigation is provided in ASME B31.8S, Appendix A3 and NACE SP0204, Section 6, “Post Assessment.” In addition, ASME B31.8S, Table 4 and PRCI LS2047, “Pipeline Repair Manual,” list industry-recognized mitigation methods for SCC. These methods are included in Table 192.613ii, below and more than one may be applied.
(2) Other mitigation methods for SCC that are not shown in the table should be performed with materials and processes suitable for the pipeline’s operating conditions and meeting applicable codes and standards.

(3) Additional guidance on mitigation methods may be found in ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas," which documents a joint industry project.

4.2 References.

(a) ASME B31.8S, Appendix A3 and Table 4 (see §192.7).
(b) ASME STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas."
(c) NACE Publication 35103, "External Stress Corrosion Cracking of Underground Pipelines."
(d) NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."
(f) OPS Advisory Bulletin ADB-03-05 (68 FR 58166, Oct. 8, 2003; see Guide Material Appendix G-192-1, Section 2).
(g) OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study," Michael Baker, Jr., Inc., January 2005.
(h) PRCI L52047, "Pipeline Repair Manual."
## INDUSTRY-RECOGNIZED MITIGATION METHODS

<table>
<thead>
<tr>
<th>Mitigation Method</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure Reduction</td>
<td>Used to decrease the likelihood of an immediate or near-term SCC failure. The pressure reduction provides time for the operator to assess the pipeline integrity and determine a long-term mitigation and management strategy.</td>
</tr>
<tr>
<td>Replacement</td>
<td>Replacement of selected pipe segments can be used to eliminate stress corrosion colonies.</td>
</tr>
<tr>
<td>Grinding</td>
<td>Removal of cracks by grinding to sound metal. Assess remaining strength, using a method such as RSTRENG, and then recoat.</td>
</tr>
<tr>
<td>Repair Sleeves, Bolt-on Clamps, or Composite Reinforcement</td>
<td>In conjunction with grinding, repair sleeves, bolt-on clamps, or composite reinforcements are able to permanently restore the serviceability of the pipe. These repair items may be installed if grinding of an excavated section of pipeline results in a wall thickness less than the minimum required for the MAOP. To mitigate SCC, the ground-out area should be filled with incompressible filler when a repair sleeve is used. The operator should follow the manufacturer’s instructions and the operator’s repair procedures.</td>
</tr>
<tr>
<td>Recoating</td>
<td>Recoating a pipeline can improve the resistance of the pipe to SCC. If disbonded, dielectric coatings (e.g., tapes, shrink sleeves) are frequent contributors to SCC. In addition, mill scale remaining on the pipe surface after preparation for coating has also been linked to SCC. Any remaining mill scale can be removed during surface preparation prior to recoating. Grit blasting conducted during the surface preparation process increases resistance to SCC by imparting a compressive residual stress on the pipe surface.</td>
</tr>
</tbody>
</table>
| Hydrostatic Testing                                     | • Hydrostatic testing and repair can be used to reduce the likelihood of a stress corrosion failure. Hydrostatic testing will cause critical cracks (at the test pressure) to fail. By repairing these failures, critical cracks are eliminated, although near-critical cracks at the test pressure could remain undetected.  
  • Using hydrostatic testing alone requires retest on a regular basis to find stress corrosion cracks that may have become critical since the previous test.  
  • Recommended hydrostatic test criteria are found in ASME B31.8S, Appendix A3.4.2. |
| In-Line Inspection                                      | In-line inspection suitable for crack detection, and subsequent repairs, can be used to reduce the likelihood of a stress corrosion failure. Examples include eddy current and electromagnetic acoustic transducer (EMAT) tools. |
| Engineering Critical Assessment                         | A written document that evaluates the risks of SCC and provides a technically defensible plan to demonstrate satisfactory pipeline safety performance. The document considers the defect growth mechanisms of the SCC process. |

**TABLE 192.613ii**
5 THREADED JOINTS

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

6 SEVERE FLOODING

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

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

(b) For buried pipelines, consider the following.

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

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

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

   (4) Determining the maximum flow or flooding conditions at river or water crossings where pipeline integrity is at risk due to flooding or scouring and having contingency plans to shut down and isolate those pipelines when such conditions occur.

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

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

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

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

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

(f) For additional information, see OPS Advisory Bulletin ADB-2016-01 (81 FR 2943, Jan 19, 2016; see Guide Material Appendix G-192-1, Section 2).

7 SERVICE LINES UNDER BUILDINGS

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

8 INTEGRITY MANAGEMENT CONSIDERATIONS

Conditions or information discovered that could affect the integrity of a pipeline should be reported to the appropriate integrity management and operating personnel.
RESERVED
§192.614  
Damage prevention program.  

(a) Except as provided in paragraphs (d) and (e) of this section, each operator of a buried pipeline shall carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation activities. For the purpose of this section, the term "excavation activities" includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earthmoving operations.

(b) An operator may comply with any of the requirements of paragraph (c) of this section through participation in a public service program, such as a one-call system, but such participation does not relieve the operator of responsibility for compliance with this section. However, an operator must perform the duties of paragraph (c)(3) of this section through participation in a one-call system, if that one-call system is a qualified one-call system. In areas that are covered by more than one qualified one-call system, an operator need only join one of the qualified one-call systems if there is a central telephone number for excavators to call for excavation activities, or if the one-call systems in those areas communicate with one another. An operator's pipeline system must be covered by a qualified one-call system where there is one in place. For the purpose of this section, a one-call system is considered a "qualified one-call system" if it meets the requirements of section (b)(1) or (b)(2) of this section.

(1) The state has adopted a one-call damage prevention program under §198.37 of this chapter; or

(2) The one-call system:
   (i) Is operated in accordance with §198.39 of this chapter;
   (ii) Provides a pipeline operator an opportunity similar to a voluntary participant to have a part in management responsibilities; and
   (iii) Assesses a participating pipeline operator a fee that is proportionate to the costs of the one-call system's coverage of the operator's pipeline.

(c) The damage prevention program required by paragraph (a) of this section must, at a minimum:

(1) Include the identity, on a current basis, of persons who normally engage in excavation activities in the area in which the pipeline is located.

(2) Provides for notification of the public in the vicinity of the pipeline and actual notification of the persons identified in paragraph (c)(1) of this section of the following as often as needed to make them aware of the damage prevention program:
   (i) The program's existence and purpose; and
   (ii) How to learn the location of underground pipelines before excavation activities are begun.

(3) Provide a means of receiving and recording notification of planned excavation activities.

(4) If the operator has buried pipelines in the area of excavation activity, provide for actual notification of persons who give notice of their intent to excavate of the type of temporary marking to be provided and how to identify the markings.

(5) Provide for temporary marking of buried pipelines in the area of excavation activity before, as far as practical, the activity begins.

(6) Provide as follows for inspection of pipelines that an operator has reason to believe could be damaged by excavation activities:
   (i) The inspection must be done as frequently as necessary during and after the activities to verify the integrity of the pipeline; and
§192.909
How can an operator change its integrity management program?

[Effective Date: 04/06/04]

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

(b) Notification. An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program’s implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.


GUIDE MATERIAL

1 CHANGES TO BE DOCUMENTED

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

(a) Information obtained from the integrity assessments.
(b) Operating experience.
(c) The operator’s understanding about the specific integrity threats and the relative importance of those threats may change.
(d) The operator’s understanding about a specific integrity assessment tool changes, and the operator chooses to use another type.
(e) Risks are different than previously understood and an operator needs to reprioritize assessments.
(f) Identification of a new HCA, which adjusts the baseline assessment plan.
(g) Development of additional program elements.

2 NOTIFICATION

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

2.1 Changes requiring notification.

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

(a) An incident on a lower-risk pipeline that would cause a reprioritization of the assessment schedule.
(b) Changes that affect the way an operator is conducting its IMP, e.g., a change to grading criteria for integrity assessment methods that subsequently affects the inspection, remediation, or prevention and mitigation activities.
(c) A merger of two companies that causes reprioritization of the assessment schedule under the merged IMP.
(d) Circumstances that would keep an operator from achieving the 2007 or 2012 assessment deadlines (e.g., weather or permit delays).

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

2.2 Changes not requiring notification.

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

(a) Editorial revisions.
(b) Schedule changes due to weather or permit delays that have no impact on meeting deadlines.
(c) Priority changes due to updated risk assessment information.

§192.911

What are the elements of an integrity management program?

[Effective Date: 07/10/06]

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

(a) An identification of all high consequence areas, in accordance with §192.905.
(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.
(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.
(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§192.925, 192.927, or 192.929.
(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment.
(f) A process for continual evaluation and assessment meeting the requirements of §192.937.
(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.
(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.
(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.
(j) Record keeping provisions meeting the requirements of §192.947.
(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.
(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.
(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by —
(1) OPS; and
(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.
(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator’s risk analysis or integrity management program to —
(1) OPS; and
(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks.

(p) A process for identification and assessment of newly-identified high consequence areas. (See §§192.905 and 192.921.)


GUIDE MATERIAL

**Note:** References to ASME throughout this section of guide material are specific to the edition of ASME B31.8S as incorporated by reference (IBR) in §192.7. Abbreviated references are used in guide material below. Example: "ASME 12.2(a)(2)" means ASME B31.8S, Paragraph 12.2(a)(2) of the IBR edition. See 3.2 of the guide material under §192.907.

1 GENERAL

The Integrity Management Program (IMP) consists of program elements encompassing the plans, processes, and procedures required for integrity management. The IMP will vary from one operator to the next, but must at least address the 16 program elements as specified in this regulation. The operator is further required to include other program elements as necessary to effectively manage pipeline integrity within the operator’s management system. In addition, the program is required to document how the processes and associated procedures will be managed and implemented.

2 FRAMEWORK

In the early stages, the IMP may not be fully developed. If the program is not fully developed, the framework describes the process for developing a complete program. The framework should identify who is responsible for individual process development and provide a timeline for the completion of the program elements. It is required that program elements be fully developed before implementation.

3 MANAGEMENT OF CHANGE (MOC) (§192.911(k))

There are two sections of Part 192 Subpart O that require operators to manage changes. First, §192.909 requires operators to document changes to the written IMP. Second, §192.911(k) requires operators to develop a written MOC process to track changes to the integrity of the pipeline. Operators may combine these requirements into a single MOC process or use separate processes. For guidance regarding IMP changes, including PHMSA-OPS notification, see guide material §192.909.

An operator may be able to manage changes that impact the integrity of the pipeline through current practices as long as the operator can demonstrate that current practices meet the requirements of ASME 11. Examples of current practices that manage change include the following.

(a) Budgeting and mapping processes that record physical pipeline changes.
(b) Work management systems that document permit requirements and acquisitions.
(c) O&M procedures or IMP manual revision logs that track written procedure changes.
(d) Organizational charts and job descriptions that establish individual responsibilities.
(e) Maps, aerial photos, or logs that document the annual HCA review.

The following guide material is based on the requirements of ASME 11.
3.1 **Objective.**

ASME 11(a) requires that MOC procedures be developed to identify and consider the impact of changes to a pipeline system and its integrity. MOC is a process for recognizing, evaluating, implementing, communicating, and documenting these changes. Both major and minor changes that impact the integrity of the pipeline, whether permanent or temporary, must be addressed.

3.2 **Types of changes.**

The operator must address changes that fall into four categories: technical, physical, procedural, and organizational. Any single change may affect more than one of these categories. Examples of changes that could impact pipeline integrity are as follows.

(a) Increase or decrease of MAOP.
(b) Increase or decrease of maximum operating pressure (see §192.917(e)).
(c) Changes to cathodic protection systems.
(d) Changes to criteria, such as grading criteria for ILI, ECDA, or ICDA.
(e) Discovery or elimination of threat.
(f) Corrections to pipeline attributes (e.g., diameter, wall thickness).
(g) New, remediated, replaced, or re-routed piping or appurtenances.
(h) Modification of gas quality or composition, such as the following.
   (1) Propane-air mixture.
   (2) Vaporized LNG.
   (3) Bio-fuels.
   (4) New production gas.
(i) Cyclic loading.
(j) Significant change in operating temperature.
(k) Flow velocity or direction.
(l) Documentation from pipe inspections.
(m) Discovering threats from continuing surveillance (e.g., encroachments, unmonitored activity on ROW).
(n) Geological events (e.g., subsidence, slips, earthquakes).

3.3 **MOC process components.**

An MOC process includes several components as outlined below. These components ensure that changes that affect the integrity of the pipeline are identified, analyzed, documented, and communicated. **Note:** These components are not required to be completed in the order shown and may be combined with others or may not be applicable.

(a) **Reason for change.**

Reason for change begins with the identification of a problem or needed improvement that affects pipeline integrity. Some examples are as follows.

(1) To comply with new or revised regulations (e.g., PHMSA, state).
(2) To incorporate process improvements or best practices.
(3) To improve reliability of pipe or equipment.
(4) System optimization.
(5) Safety improvements.
(6) Changes in technology.

(b) **Authority for approving changes.**

The operator should identify the level of authority necessary to approve various types of changes. When approving the change, consideration should be given to seeking input from other affected stakeholders. Some changes may be pre-approved in accordance with an operator’s procedure. For example, when a criterion is met for a certain defect, the procedure may authorize repair or replacement of the pipe.

(c) **Analysis of implications.**

The operator must evaluate the change and determine the impact to the integrity of the pipeline. The analysis should determine if the change increases or decreases threats to the pipeline.
4.6 Prior assessments.
Evaluating the findings from prior assessments (e.g., in-line inspection, pressure tests, internal corrosion direct assessment) and resulting remedial actions can provide useful data in determining the threat of internal corrosion.

The risk of internal corrosion could increase after hydrostatic testing due to the following.
(a) Water or debris left in the pipeline after hydrostatic testing.
(b) The test water contains bacteria that promote MIC.

4.7 Gas, liquid, and solid sampling analysis.
Analysis of gas, liquid, and solid samples can be used to help determine the probability of internal corrosion and help identify the cause of corrosion. Data should be trended to determine if values are increasing or decreasing.
(a) Gas. When analyzing for internal corrosion, partial pressures (see 4.10 below) and gas chemistry are important considerations. Typical gas analysis should include the determination of the following constituents.
   (1) Carbon dioxide (CO₂). CO₂ in the gas can mix with water in the gas stream to form carbonic acid, which is corrosive to steel. The percentage of CO₂ in the gas stream can be determined by using a stain tube or analyzing the sample by gas chromatography. CO₂ partial pressure below 3 psia is generally considered non-corrosive. See 15.1.4 and 15.1.5 below. The table below identifies typical concern levels for CO₂ partial pressures.

<table>
<thead>
<tr>
<th>CO₂ Partial Pressure (psia)</th>
<th>Level of Concern</th>
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<tbody>
<tr>
<td>&lt; 3</td>
<td>Low Risk</td>
</tr>
<tr>
<td>3 – 30</td>
<td>Moderate Risk</td>
</tr>
<tr>
<td>&gt; 30</td>
<td>High Risk</td>
</tr>
</tbody>
</table>

   (2) Hydrogen sulfide (H₂S).
      (i) H₂S may be a normal constituent in natural gas, and can also be formed due to MIC. H₂S will combine with water to form a weak sulfuric acid which is corrosive to steel. The presence of H₂S may also cause hydrogen blistering and sulfide stress cracking.
      (ii) The amount of H₂S in the gas stream may be determined by using a stain tube or an electronic meter. The stain tube typically provides a read out in ppm which, if necessary, is then converted to percentage. Electronic meters give a direct reading of the percent of H₂S in the gas.
      (iii) A typical operator-set tariff range for H₂S is between 4 and 16 ppm. Gas maintained at tariff quality is considered a low concern for internal corrosion caused by H₂S.
   (3) Oxygen (O₂). O₂ is often present in small amounts in natural gas and, when present in a gas stream containing water, can act as a catalyst to speed up general and pitting corrosion. O₂ can be measured with a stain tube or by gas chromatography. If O₂ is indicated, the dissolved O₂ concentration in water should be calculated. A dissolved O₂ concentration above 10 to 50 ppm is considered corrosive to steel pipelines.
Water content or dew point. For corrosion to occur there must be an electrolyte, such as water, present to react with the gas constituents. High dew points may allow water to condense at certain locations and activate corrosion mechanisms. Water content in the gas stream can be measured with either a stain tube or an electronic meter. Both devices determine the amount of water in pounds per million cubic feet (lbs/MMSCF) of the gas. A value of less than 7 lbs/MMSCF is generally considered non-corrosive. At higher concentrations and certain pressure and temperature conditions, it is possible for water vapor to condense.

(b) Liquid. For evaluating internal corrosion, only liquids containing electrolytes need to be analyzed. Non-electrolytes, such as drip gas and other hydrocarbons, may not need to be analyzed because they do not contribute to corrosion. Water indicators are available to determine if the sample contains electrolytes. When analyzing for internal corrosion, a typical liquid analysis includes the following.

1. pH. The pH measures the acidity or alkalinity. A pH of 7 is neutral. A reading of less than 7 is acidic, with lower numbers indicating a stronger acid. Readings above 7 are alkaline, with higher numbers indicating a stronger base. Readings near neutral represent less corrosive liquids. Low pH levels, such as 5.0 or less, may result in increased corrosion.

2. Iron or manganese.
   (i) Iron might exist naturally in liquids in small amounts. Manganese is not normally present in liquids produced from natural gas sources, but is present in steel.
   (ii) Iron concentrations above 2500 ppm or manganese concentrations above 25 ppm may indicate corrosion of steel. A manganese to iron ratio between 1:50 and 1:200 may indicate the source of iron is from corrosion. Deviations from this ratio range could indicate the presence of other material or other chemical mechanisms. See 15.1.6 below.
   (iii) Due to precipitation of iron from the liquid sample, a lower iron concentration in solution may not indicate a reduced rate of corrosion. Proper handling of samples should be ensured to prevent precipitation.
   (iv) When analyzing iron and manganese counts, the system parameters (e.g., flow rate, amount of water, temperature) should be reviewed and scaling tendency should be determined.

3. Salt or chlorides. Salt, or more specifically chloride, is not in itself corrosive. Water containing chlorides or other salts tend to be more corrosive than fresh water. The type and concentration of anions in the sample can be used to predict acceleration of corrosion activity (e.g., when chloride ions are present) or inhibition of corrosion activity.

(c) Solids. Solids should be sampled whenever they are found inside the pipe. Bacteria cultures (see 4.8 below) and pH need to be taken immediately upon exposing the solids, because the values may change when exposed to air. A typical solid analysis includes the following.

1. Iron sulfide (FeS$_2$). Iron sulfide is a byproduct of the reaction of H$_2$S and steel, and is also produced by sulfate reducing bacteria. It may be identified as the mineral pyrite or marcasite. Iron sulfide often coats the internal surface of pipe, but because iron sulfide is cathodic to steel, breaks in the scale may often cause acceleration of pitting.

2. Mineral scale. Mineral scale may contain a variety of components and compounds, depending on the contaminants and environment. Scale should be examined to determine actual composition, which may suggest corrosion mechanisms. Mineral scale might include salt, calcium and other carbonates, sulfide minerals, as well as a variety of iron minerals. Iron found in a solid sample that has accumulated in vessels, loosened during cleaning pig runs, or debris found when a cutout is made on the line typically represents corrosion product. When evaluating for iron, manganese should also be evaluated.

3. Erosive material. Material and other debris, such as sand, quartz, and black powder, might be present in pipeline solids and may create erosion corrosion issues.
14.7 Validation.
Validation of the risk assessment results is an ongoing process ensuring that the methods used have produced results consistent across the pipeline system and with other industry experience. The validation is a review to determine whether the integrity assessment results are as expected. Additionally, spot inspections in the field and evaluations of low-risk and high-risk pipeline segments may be performed to validate that the model is correctly characterizing the risks. When an operator obtains additional data that may affect the outcome and corresponding rankings, the risk assessment process and associated schedules and procedures should be modified using the operator's management of change process (see guide material under §192.911). Additional data can include information from pipeline maintenance or other activities that identify inaccuracies in the characterization of risk for the pipeline segment or other similar segments. Validation may be performed by one or more of the following.
(a) An analysis by SMEs.
(b) Modeling known failures to determine if the results produce high risk.
(c) Comparison to another model.
(d) Comparison of results with expectations.

If there are discrepancies in the validation, it does not necessarily mean that the risk ranking is wrong. What it does indicate is that there is a difference that needs to be understood. It could be that the risk model failed to incorporate some important factors, or it may be that there are factors important to risk that SMEs and operations personnel did not recognize because they have never faced them. It is important that the operator understands the reasons for the difference, makes necessary adjustments to its risk assessment, and has confidence that the final results accurately represent its system.

14.8 Records.
An operator is required to document the risk assessment (§192.947(b)). See guide material under §192.947.

15 REFERENCES

15.1 Steel pipe.

15.1.4 GRI-02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology" (see §192.7).
15.1.5 NACE SP0106, "Control of Internal Corrosion in Steel Pipelines and Piping Systems."
15.1.6 Section 4.3.2 of NACE SP0192-12, "Monitoring Corrosion in Oil and Gas Production with Iron Counts."
15.1.7 NACE SP0204, "Stress Corrosion Cracking (SCC) Direct Assessment Methodology."
15.1.8 OPS Technical Task Order Number 8, "Stress Corrosion Cracking Study", Michael Baker Jr., Inc., January 2005, at:
15.1.9 ASME 100396, "History of Line Pipe Manufacturing in North America.
15.1.10 "Integrity Characteristics of Vintage Pipelines," INGAA.

15.1.13 OPS Alert Notices and Advisory Bulletin:

| ALN-88-01       | Operational failures of pipelines constructed with ERW prior to 1970 (Jan 28, 1988) |
| ALN-89-01       | Update to ALN-88-01 (Mar 8, 1989) |
| ADB-09-01       | Potential Low and Variable Yield and Tensile Strength and Chemical Composition Properties in High Strength Line Pipe. (74 FR 23930, May 21, 2009) |


15.1.15 Section 841.231 of ASME B31.8, "Gas Transmission and Distribution Piping Systems" (see §192.7).


15.2 Plastic pipe.

15.2.1 OPS Advisory Bulletins:

| ADB-86-02       | Plastic Piping, Mechanical Coupling (Feb. 26, 1986) |
| ADB-99-01       | Susceptibility of Certain Polyethylene Pipe Manufactured by Century Utility Products, Inc. to Premature Failure Due to Brittle-Like Cracking (64 FR 12211, Mar. 11, 1999) |
| ADB-99-02       | Potential Susceptibility of Plastic Pipe Installed Between the [Years] 1960 and the Early 1980s to Premature Failure Due to Brittle-Like Cracking (64 FR 12212 Mar. 11, 1999) |
| ADB-02-07       | Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe (67 FR 70806, Nov. 26, 2002) |
| ADB-07-02       | Updated Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe (72 FR 51301, Sept. 6, 2007) |
| ADB-12-03       | Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation (77 FR 13387, Mar. 6, 2012) |

15.2.2 Plastic Pipe Database Committee (PPDC) reports at: www.aga.org/Kc/OperationsEngineering/ ppdc/Status%20Reports/Pages/default.aspx
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<td>SSPC Painting Manual Good Painting Practice - Volume 1; and Systems and Specifications - Volume 2</td>
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<td>ASTM D696 Test Method for Coefficient of Linear Thermal Expansion of Plastics Between -30 °C and 30 °C With a Vitreous Silica Dilatometer</td>
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(See guide material under §§192.503, 192.505, 192.507, 192.513, 192.619, 192.921, and Guide Material Appendix G-192-9)

PRESSURE TESTING GUIDELINES FOR TRANSMISSION INTEGRITY ASSESSMENTS

1 GENERAL

(a) Pressure testing new and existing steel and plastic (e.g., polyethylene) transmission pipelines is an assessment method that may be used by operators to confirm the integrity of pipelines from time-dependent threats (e.g., internal corrosion, external corrosion, stress corrosion cracking) and time-independent threats (e.g., manufacturing defects, excavation damage, construction damage).

(b) Pressure testing identifies, through failure, major defects that might threaten a pipeline's integrity or shows that no major flaws were revealed at the time of testing.

(c) Retesting should be considered for existing steel and plastic transmission pipelines when the following conditions exist.
   (1) For steel pipelines, direct assessment is not an appropriate assessment method.
   (2) In-line inspection tools are not appropriate or available.
   (3) The pipe segment cannot accommodate the passage of in-line inspection tools due to restrictions in components, such as elbows or valves.
   (4) Operator can maintain service to affected customers by having bi-directional system flow, an alternative supply source, or flexibility to take the pipe segment out of service.
   (5) The gas flow or other pipeline conditions are not sufficient for running in-line inspection tools.

(d) See Guide Material Appendix G-192-9 for guidelines in selecting an appropriate pressure testing medium for steel and plastic transmission pipe segments.

(e) Consideration should be given to the qualifications required for personnel involved in pressure testing.

2 PRESSURE TESTING ADVANTAGES AND DISADVANTAGES

See guide material under §192.921 for the advantages and disadvantages of pressure testing new and existing steel and plastic pipelines.

3 PRESSURE TESTING OF STEEL TRANSMISSION PIPELINES

To optimize pressure testing as an integrity assessment tool, pressure testing of new and existing steel transmission pipelines should be conducted in accordance with Subpart J. Operators should consider testing at a higher pressure to detect the greatest number of flaws in the pipe segment.

3.1 Pressure testing new steel transmission pipelines.

(a) The test pressure may be above 100% SMYS at the lowest elevation to provide an adequate test pressure at the highest elevation to ensure fitness for service.

(b) When any portion is tested above 100% SMYS, a pressure-volume plot should be used to identify yielding. The test should be stopped if yielding occurs. For additional information on testing to yield, see ASME B31.8, Appendix N (see §192.7).

(c) A pressure test of a new steel transmission pipeline is one of the factors used to establish the MAOP of the test section as a result of the pressure achieved for the proper duration of time (see §192.619(a)(2)).
3.2 Pressure testing existing steel transmission pipelines. 
When considering pressure testing an existing transmission pipeline, the method of determining MAOP should be reviewed. For pipelines with an MAOP established by grandfathering or maximum safe pressure (§192.619(a)(3) or (4), and §192.619(c)), existing data, such as materials, and the operating and maintenance history should be examined to determine if testing is a suitable assessment method.
An operator may review information, if available, from prior pressure testing of the existing pipeline segment. If pressure testing is performed to the highest level attainable for an existing steel transmission pipeline based on its design (i.e., grade, wall thickness, seam type, component ratings, and other factors), then the integrity of the pipeline will be subject to the following conditions.
(a) Few longitudinally oriented flaws will remain in the test section provided that a sufficiently high ratio of test pressure to MAOP is achieved.
(b) Pipe integrity is validated if the differential increases between the size of the surviving flaws and the flaw size required to produce a future pipe failure.
(c) Pressure testing reflects the condition of the test section at a specific point in time. Minor defects, if present, will remain in an undetected state and may continue to grow over time.
(d) Failure resulting from "pressure reversal" is a potential hazard that can occur after testing has been completed. Pressure reversal occurs when a sub-critical defect survives a higher test pressure, but then fails at a lower pressure in a subsequent repressurization due to continued growth of the defect over time.
(e) Testing does not provide a measure of corrosion-caused metal loss, or information about the presence, extent, and severity of dents and gouges from excavation or construction damages. In addition, the test pressure at the time may not be high enough to cause failure of these defects.
(f) The threat of internal corrosion exists for a pipe segment that is not properly dewatered and dried after being hydrostatically tested.

3.3 General pressure testing considerations for steel transmission pipelines.
(a) Pressure tests used for integrity assessments on new or existing steel pipelines must be performed in accordance with the requirements of Subpart J and §192.921.
(b) The following factors may be considered when selecting a test pressure for an existing pipeline.
(1) Mill test certificates to ascertain the pressure test levels in the manufacturing process and pipe data pertaining to specified minimum yield strength along with seam and joint data. If not available, check the specification (e.g., API 5L - see §192.7 for IBR) applicable to the pipe’s manufacturing date to obtain industry specifications for mill testing and pipe data.
(2) Previous pressure test results from time of construction or MAOP upgrades.
(3) Prior integrity assessments and operating history.
(4) Number of test failures that will be acceptable to the operator when testing. The probability of pressure reversal failure occurring after completing the test increases with the number of failures permitted during testing. In determining the level of acceptable failures, operators may consider the following factors.
   (i) Likelihood and consequence of a failure.
      (A) Pipe location.
      (B) Age and condition of pipe.
      (C) Pipe welds.
      (D) Maintenance history of pipe.
   (ii) Safety of testing personnel.
(5) Identification of potential safety issues during testing, such as the presence of existing mechanical couplings.
(6) Integrity assessment intervals based on test pressure attained (see Table 3.3 below which is excerpted from ASME B31.8S-2004, Table 3 - see §192.7 for IBR). If the maximum permitted time interval for a pressure test exceeds 7 years, a confirmatory direct assessment or other assessment must be conducted at intervals not exceeding 7 years (see §192.939).
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