ASME PTB-9-2014

ASME Pipeline Standards Compendium

SETTING THE STANDARD

PTB-9-2014

ASME PIPELINE STANDARDS COMPENDIUM

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FOREWORD

Established in 1880, The American Society of Mechanical Engineers (ASME) is a professional not-for-profit organization with more than 135,000 members and volunteers promoting the art, science and practice of mechanical and multidisciplinary engineering and allied sciences. ASME develops codes and standards that enhance public safety, and provides lifelong learning and technical exchange opportunities benefiting the engineering and technology community. Visit www.asme.org for more information.

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ASME
Director, Pressure Technology
Two Park Avenue
New York, NY 10016-5990

1 INTRODUCTION

This compendium describes each ASME standard referenced in 49 of the Code of Federal Regulations (CFR) Part 192, 49 CFR Part 193, and 49 CFR Part 195. For each 49 CFR Part the referenced ASME standard will be identified and, in the case of ASME B31.8S and certain other ASME standards, the relevant text will be included in this compendium.

It is intended that the reader of this compendium document will be initially reviewing the federal pipeline safety regulations and then reviewing the referenced ASME standard. This compendium document has been structured to facilitate this usage pattern.

ASME pressure technology codes and standards are used in numerous applications across various industrial sectors. This compendium is intended to aggregate those pressure-related requirements applicable to United States federal pipeline safety regulations where ASME standards are referenced, i.e., 49 CFR Part 192, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards;" 49 CFR Part 193, "Liquefied Natural Gas Facilities: Federal Safety Standards;" and 49 CFR Part 195, "Transportation of Hazardous Liquids by Pipeline."

This compendium is not intended to be a complete standard covering all aspects of piping safety, including design, fabrication, installation, inspection and maintenance and should not be considered a substitution for the application of sound engineering judgment. Readers are encouraged to refer to the current version of the applicable ASME standard.

References for ASME Standards and Codes within this compendium use the versions listed in Figure 1-1.

Figure 1-1: Summary of Referenced Standards

Designator	Title	Year
ASME B16.1	Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)	2010
ASME B16.5	Pipe Flanges and Flanged Fittings	2013
ASME B16.9	Factory-Made Wrought Buttwelding Fittings	2012
ASME B31G	Manual for Determining the Remaining Strength of Corroded Pipelines.	2012
ASME B31.4	Pipeline Transportation Systems for Liquids and Slurries	2012
ASME B31.8	Gas Transmission and Distribution Piping Systems	2012
ASME B31.8S	Supplement to B31.8 on Managing System Integrity of Gas Pipelines.	2012
ASME BPVC	Boiler & Pressure Vessel Code, Section I, Rules for Construction of Power Boilers	2013
ASME BPVC	Boiler & Pressure Vessel Code, Section VIII, Division 1, Rules for Construction of Pressure Vessels	2013
ASME BPVC	Boiler & Pressure Vessel Code, Section VIII, Division 2, Alternative Rules, Rules for Construction of Pressure Vessels	2013
ASME BPVC	Boiler & Pressure Vessel Code, Section IX, Welding, Brazing, and Fusing Qualifications	2013

2 49 CFR 192 – TRANSPORATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

2.1 Design of Pipeline Components

2.1.1 CFR Reference: 192.147 Flanges and Flange Accessories

2.1.1.1 CFR Language: 192.147(a)

Each flange or flange accessory (other than cast iron) must meet the minimum requirements of ASME/ANSI B16.5, MSS SP-44, or the equivalent.

2.1.1.2 ASME Standard Reference

The CFR references ASME B16.5 "Pipe Flanges and Flanged Fittings: NPS ½ through NPS 24 Metric/Inch Standard", in its entirety.

2.1.1.3 CFR Language: 192.147(c)

Each flange on a flanged joint in cast iron pipe must conform in dimensions, drilling, face and gasket design to ASME/ANSI B16.1 and be cast integrally with the pipe, valve, or fitting.

2.1.1.4 ASME Standard Reference

The CFR references ASME B16.1 "Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)" in its entirety.

2.1.2 CFR Reference: 192.153 Components Fabricated by Welding

2.1.2.1 CFR Language: 192.153(a)

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

2.1.2.2 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section VIII, Division I, "Rules for Construction of Pressure Vessels", paragraph UG-101.

2.1.2.3 CFR Language: 192.153(b)

(b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with Section I, Section VIII, Division 1, or Section VIII, Division 2 of the ASME Boiler and Pressure Vessel Code, except for the following:
   - *(1)* Regularly manufactured buttwelding fittings.
   - *(2)* Pipe that has been produced and tested under a specification listed in appendix B to this part.
   - *(3)* Partial assemblies such as split rings or collars.
   - *(4)* Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions.

2.1.2.4 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section VIII, Division I, "Rules for Construction of Pressure Vessels" in its entirety and ASME Boiler & Pressure Vessel Code, Section VIII, Division 2, "Alternative Rules, Rules for Construction of Pressure Vessels" in its entirety.

2.1.2.5 CFR Language: 192.153(d)

(d) Except for flat closures designed in accordance with Section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails may not be used on pipe that either operates at 100 psi (689 kPa) gage, or more, or is more than 3 inches (76 millimeters) nominal diameter.

2.1.2.6 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section VIII, Division I, "Rules for Construction of Pressure Vessels" in its entirety and ASME Boiler & Pressure Vessel Code, Section VIII, Division 2, "Alternative Rules, Rules for Construction of Pressure Vessels" in its entirety.

2.1.3 CFR Reference: 192.165 Compressor Stations: Liquid Removal

2.1.3.1 CFR Language: 192.165(b)(3)

(b) Each liquid separator used to remove entrained liquids at a compressor station must:
   (3) Be manufactured in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code, except that liquid separators constructed of pipe and fittings without internal welding must be fabricated with a design factor of 0.4, or less.

2.1.3.2 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section VIII, Division I, "Rules for Construction of Pressure Vessels" in its entirety and ASME Boiler & Pressure Vessel Code, Section VIII, Division 2, "Alternative Rules, Rules for Construction of Pressure Vessels" in its entirety.

2.2 Welding of Steel in Pipelines

2.2.1 CFR Reference: 192.227 Qualification of Welders

2.2.1.1 CFR Language: 192.227(a)

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

2.2.1.2 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section IX, "Welding and Brazing Procedures, Welders, Brazers, and Welding and Brazing Operators" in its entirety.

2.3 Joining of Materials Other Than by Welding

2.3.1 CFR Reference: 192.279 Copper Pipe

2.3.1.1 CFR Language: 192.279

Copper pipe may not be threaded except that copper pipe used for joining screw fittings or valves may be threaded if the wall thickness is equivalent to the comparable size of Schedule 40 or heavier wall pipe listed in Table C1of ASME/ANSI B16.5.

2.3.1.2 ASME Standard Language

The CFR references ASME B16.5 “Pipe Flanges and Flanged Fittings: NPS ½ through NPS 24 Metric/Inch Standard”. For user convenience, Table C1 of ASME B16.5 has been included as Figure 2-1.

Figure 2-1: Flange Bolting Dimensional Recommendations (B16.5 – Table C1)

Product	Carbon Steel [Note (1)]	Alloy Steel
Stud bolts	ASME B18.2.1	ASME B18.2.1
Bolts smaller than ¾ in.	ASME B18.2.1, square or heavy hex head	ASME B18.2.1, heavy hex head
Bolts equal to or larger than ¾ in.	ASME B18.2.1, square or heavy hex head	ASME B18.2.1, heavy hex head
Nuts smaller than ¾ in.	ASME B18.2.2, heavy hex	ASME B18.2.2, heavy hex
Nuts equal to or larger than ¾ in.	ASME B18.2.2, hex or heavy hex	ASME B18.2.2, heavy hex
External threads	ASME B1.1, Cl. 2A coarse series	ASME B1.1, Cl. 2A coarse series up through 1 in.; eight thread series or larger bolts
Internal threads	ASME B1.1, Cl. 2B coarse series	ASME B1.1, Cl. 2B coarse series up through 1 in.; eight thread series for larger bolts

NOTE:
(1) When B18.2.1 bolting is used, it should be threaded as close to the head as applicable to continuous and double-end stud bolts.

2.4 Requirements for Corrosion Control

2.4.1 CFR Reference: 192.485 Remedial Measures: Transmission Lines

2.4.1.1 CFR Language: 192.485(c)

Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3-805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

2.4.1.2 ASME Standard Reference

The CFR references ASME B31G “Manual for Determining the Remaining Strength of Corroded Pipelines” in its entirety.

2.5 Operations

2.5.1 CFR Reference: 192.619 What is the Maximum Allowable Operating Pressure for Steel or Plastic Pipelines?

2.5.1.1 CFR Language: 192.619(a)(1)(i)

(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 pipeline 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 pressure 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, se 192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

2.5.1.2 ASME Standard Language

The CFR references ASME B31.8 "Gas Transmission and Distribution Piping Systems", Appendix N. For user convenience, Appendix N of B31.8 has been included below.

2.5.1.2.1 Recommended Practice for Hydrostatic Testing of Pipelines in Place (B31.8 - Nonmandatory Appendix N)

2.5.1.2.1.1 Introduction (B31.8 - N-1)

The purpose of the recommended practice is to cite some of the important steps that should be taken in hydrostatic testing of in-place pipelines. It is intended to provide basic guidelines only. The portions of this recommended practice, which covers the determination of the pressure at which the pipe specified minimum yield strength is reached, are only used when such determination is needed.

2.5.1.2.1.2 Planning (B31.8 - N-2)

(a) All pressure tests shall be conducted with due regard for the safety of people and property. When the test pressure is above 400 psig (2,760 kPa), appropriate precautions shall be taken to keep people not engaged in the testing operations out of the testing area while conducting the hydrostatic test.

(b) Selection of Test Sections and Test Sites. The pipeline may need to be divided into sections for testing to isolate areas with different test pressure requirements, or to obtain desired maximum and minimum test pressures due to hydrostatic head differential. The elevation at the test site, the high point and low point of the isolated area, must be known to maintain the specified pressure at the maximum and the minimum elevations.

(c) Water Source and Water Disposal. A water source, as well as location(s) for water disposal, should be selected well in advance of the testing. Federal, state, and local regulations should be checked to ensure compliance with respect to usage and/or disposal of the water. In disposing of the water after testing, care should be taken to prevent damage to crops and excessive erosion or contamination of streams, rivers, or other waterbodies including groundwater.

(d) *Ambient Conditions* - Hydrostatic testing in low temperature conditions may require
- *(1)* heating of test medium.

(2) the addition of freeze point depressants. Caution should be exercised in the handling of freeze point depressants during tests. Disposal of freeze point depressants must be carefully planned and executed.

2.5.1.2.1.3 Filling (B31.8 - N-3)

Filling is normally done with a high-volume centrifugal pump or pumps. Filling should be continuous and be done behind one or more squeegees or spheres to minimize the amount of air in the line. The progress of filling should be monitored by metering the water pump into the pipeline and calculating the volume of line filled. If necessary, a period of temperature stabilization between the ground and fill water should be provided.

2.5.1.2.1.4 Testing (B31.8 - N-4)

(a) *Pressure Pump* - Normally, a positive displacement reciprocating pump is used for pressurizing the pipeline during test. The flow capacity of the pump should be adequate to provide a reasonable pressurizing rate. The pressure rating of the pump must be higher than the anticipated maximum test pressure.

(b) *Test Heads, Piping, and Valves* - The design pressure of the test heads and piping and the rated pressure of hoses and valves in the test manifold shall be no less than the anticipated test pressure. All equipment should be inspected prior to the test to determine that it is in satisfactory condition.

(c) *Pressurization* - Following is a sequence for pressurization.

- *(1)* Raise the pressure in the section to no more than 80% of anticipated test pressure and hold for a time period to determine that no major leaks exist.
- *(2)* During this time period, monitor the pressure and check the test section for leakage. Repair any major leaks that are found.
- *(3)* After the hold time period, pressurize at a uniform rate to the test pressure. Monitor for deviation from a straight line by use of pressure-volume plots (logs or automatic plotter).
- *(4)* When the test pressure is reached and stabilized from pressuring operations, a hold period may commence. During this period, test medium may be added as required to maintain the minimum test pressure.

2.5.1.2.1.5 Determination of Pressure Required to Produce Yielding (B31.8 - N-5)

(a) *Pressure-Volume Plot Methods* - If monitoring deviation from a straight line with graphical plots, an accurate plot of pressure versus the volume of water pumped into the line may be made either by hand or automatic plotter. To make a hand plot, the pump strokes are counted to determine volume and plotted against pressure readings. The plot should be started at a pressure low enough to establish accurately the straight-line portion of the pressure-volume plot. The points should be plotted frequently enough so that deviation from the straight-line portion can be detected readily. The deviation from the straight line is the start of the nonlinear portion of the pressure-volume plot and indicates that the elastic limit of some of the pipe within the section has been reached.

(b) Yield for unidentified or used pipe [as limited by ASME B31.8 para. 841.1.4(a) and allowed under paras. 811.1(f) and 817.1.3(h)] is determined by using the pressure at the highest elevation within a test section, at which the number of pump strokes (measured volume) per increment of pressure rise becomes twice the number of pump strokes (measured volume) per increment of pressure rise that was required during the straight-line part of the pressure-volume plot before any deviation occurs.

(c) For control of maximum test pressure when hoop stress levels exceed 100% SMYS within a test section, one of the following measures may be used:

- *(1)* The pressure at which the number of pump strokes (measured volume) per increment of pressure rise becomes twice the number of pump strokes (measured volume) per increment of pressure rise that was required during the straight-line part of the pressure-volume plot before any deviation occurs.

(2) The pressure shall not exceed the pressure occurring when the number of pump strokes (measured volume) taken after deviation from the straight-line part of the pressure-volume plot, times the volume per stroke, is equal to 0.002 times the test section fill volume at atmospheric pressure. This represents the average behavior of the test section. Individual pipe lengths may experience greater or smaller expansion based on their respective mechanical properties.

2.5.1.2.1.6 Leak Testing (B31.8 - N-6)

If, during the hold period, leakage is indicated, the pressure may be reduced while locating the leak. After the leak is repaired, a new hold period must be started at full test pressure.

2.5.1.2.1.7 Records (B31.8 - N-7)

The operating company shall maintain in its file for the useful life of each pipeline and main, records showing the following:

(a) test medium
(b) test pressure
(c) test duration
(d) test date
(e) pressure recording chart and pressure log
(f) pressure versus volume plot (if applicable)
(g) pressure at high and low elevations
(h) elevation at point test pressure measured
(i) person(s) conducting test, operator, and testing contractor, if utilized
(j) environmental factors (ambient temperature, raining, snowing, windy, etc.)
(k) manufacturer (pipe, valves, etc.)
(l) pipe specifications (SMYS, diameter, wall thickness, etc.)
(m) clear identification of what is included in each test section
(n) description of any leaks or failures and their disposition

The above records shall be reviewed to ensure that the requirements of this Code [ASME B31.8] have been met.

Note: Many sections of ASME B31.8S are incorporated by reference, but not all. For user convenience, each CFR reference text will be included as well as the complete text of the Code corresponding reference.

2.6 Gas Transmission Pipeline Integrity Management

2.6.1 CFR Reference: 192.903 What Definitions Apply to this Subpart?

2.6.1.1 CFR Language: 192.903(c)

(c) A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula R = 0.69* (square root of (p*d2)), where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

***Note*:** 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use Section 3.2 of ASME/ANSI B31.8S-2001 (Supplement to ASME B31.8; incorporated by reference, see 192.7) to calculate the impact radius formula.
Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

2.6.1.2 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines", Section 3.2. For user convenience, Section 3 of B31.8S has been included below.

2.6.1.2.1 Consequences (B31.8S - 3)

2.6.1.2.1.1 General (B31.8S - 3.1)

Risk is the mathematical product of the likelihood (probability) and the consequences of events that result where from a failure. Risk may be decreased by reducing either the likelihood or the consequences of a failure, or both. This section specifically addresses the consequence portion of the risk equation. The operator shall consider consequences of a potential failure when prioritizing inspections and mitigation activities.

The B31.8 Code manages risk to pipeline integrity by adjusting design and safety factors, and inspection and maintenance frequencies, as the potential consequences of a failure increase. This has been done on an empirical basis without quantifying the consequences of a failure.

Subsection 2.6.1.2.1.2 describes how to determine the area that is affected by a pipeline failure (potential impact area) in order to evaluate the potential consequences of such an event. The area impacted is a function of the pipeline diameter and pressure.

2.6.1.2.1.2 Potential Impact Area (B31.8S - 3.2)

The refined radius of impact for natural gas is calculated using the formula

$$r = 0.69 \cdot d\sqrt{p} \qquad (r = 0.00315 \cdot d\sqrt{p}) \qquad (1)$$

where
$d = o \quad de\ diame \quad r\ of\ the\ pipeline, in. (mm)$
$p =$ pipeline segment's maximum allowable operating pressure (MAOP), psig (kPa)
$r =$ radius of the impact circle, ft (m)

EXAMPLE 1: A 30 in. diameter pipe with a maximum allowable operating pressure of 1,000 psig has a potential impact radius of approximately 660 ft.

$$\begin{aligned} r &= 0.69 \cdot d\sqrt{p} \\ &= 0.69 \cdot (30\text{ in.})\left(1{,}000\,\frac{\text{lb}}{\text{in}^2}\right)^{\frac{1}{2}} \\ &= 654.6\text{ ft} \approx 660\text{ ft} \end{aligned}$$

EXAMPLE 2: A 762 mm diameter pipe with a maximum allowable operating pressure of 6,900 kPa has a potential impact radius of approximately 200 m.

$$r = 0.00315 \cdot d\sqrt{p}$$
$$= 0.00315 \cdot 762\ \text{mm}\ (6{,}900\ \text{kPa})^{\frac{1}{2}}$$
$$= 199.4\ \text{m} \approx 200\ \text{m}$$

Use of this equation shows that failure of a smaller diameter, lower pressure pipeline will affect a smaller area than a larger diameter, higher pressure pipeline. (See GRI-00/0189.)

NOTE: 0.69 is the factor for natural gas using U.S. Customary units and 0.00315 is the factor using metric units. Other gases or rich natural gas shall use different factors.

Equation (1) is derived from

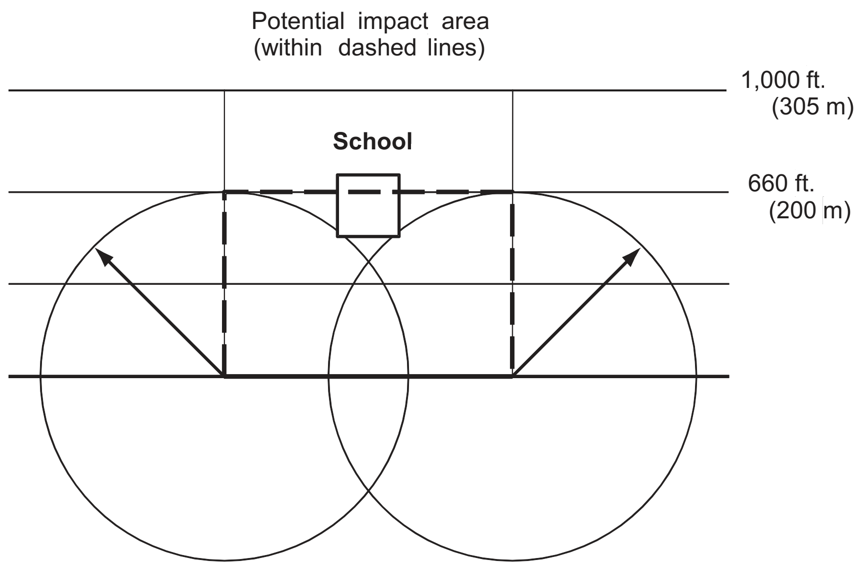
$$r = \sqrt{\frac{115{,}920}{8} \cdot \mu \cdot \chi_g \cdot \gamma \cdot C_d \cdot H_C \cdot \frac{Q}{a_o} \cdot \frac{p^{\ 2}}{I_t}}$$

where

a_o = sonic velocity of gas = $\sqrt{\frac{\gamma RT}{m}}$

C_d = discharge coefficient
d = line diameter
H_C = heat of combustion
I_t = threshold heat flux
m = gas molecular weight
p = live pressure
Q = flow factor = $\gamma \left(\frac{2}{\gamma + 1}\right)^{\frac{\gamma}{2(\gamma\quad)}}$
R = gas constant
r = refined radius of impact
T = gas temperature
γ = specific heat ratio of gas
λ = release rate decay factor
μ = combustion efficiency factor
χ_g = emissivity factor

Figure 2-2: Potential Impact Area (B31.8S - Fig 3.2-1)



GENERAL NOTE: This diagram represents the results for a 30 in. (762 mm) pipe with an MAOP of 1,000 psig (6,900 kPa).

In a performance-based program, the operator may consider alternate models that calculate impact areas and consider additional factors, such as depth of burial that may reduce impact areas. The operator shall count the number of houses and individual units in buildings within the potential impact area. The potential impact area extends from the center of the first affected circle to the center of the last affected circle (see Figure 2-2). This housing unit count can then be used to help determine the relative consequences of a rupture of the pipeline segment.

The ranking of these areas is an important element of risk assessment. Determining the likelihood of failure is the other important element of risk assessment (see Subsections 2.6.5.4.1 and 2.6.5.6.1).

2.6.1.2.1.3 Consequence Factors to Consider (B31.8S - 3.3)

When evaluating the consequences of a failure within the impact zone, the operator shall consider at least the following:
(a) population density
(b) proximity of the population to the pipeline (including consideration of manmade or natural barriers that may provide some level of protection)
(c) proximity of populations with limited or impaired mobility (e.g., hospitals, schools, childcare centers, retirement communities, prisons, recreation areas), particularly in unprotected outside areas
(d) property damage
(e) environmental damage
(f) effects of unignited gas releases
(g) security of gas supply (e.g., impacts resulting from interruption of service)
(h) public convenience and necessity
(i) potential for secondary failures

Note that the consequences may vary based on the richness of the gas transported and as a result of how the gas decompresses. The richer the gas, the more important defects and material properties are in modeling the characteristics of the failure.

2.6.2 CFR Reference: 192.907 What Must an Operator Do to Implement this Subpart?

2.6.2.1 CFR Language: 192.907(b)

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, see 192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

2.6.2.2 ASME Standard Language

49 CFR 192.907(b) does not contain direct reference to ASME B31.8S. However, B31.8S Section 1.1, Scope, best illustrates the intent of 192.907(b) and is included below for convenience.

2.6.2.2.1 Scope (B31.8S – 1.1)

This Code [ASME B31.8S] applies to onshore pipeline systems constructed with ferrous materials and that transport gas. The principles and processes embodied in integrity management are applicable to all pipeline systems.

This Code [ASME B31.8S] is specifically designed to provide the operator (see definition below) with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes. The processes and approaches within this Code [ASME B31.8S] are applicable to the entire pipeline system.

Definition: *operator or operating company*: individual, partnership, corporation, public agency, owner, agent, or other entity currently responsible for the design, construction, inspection, testing, operation, and maintenance of the pipeline facilities.

Note: 192.911 references four (4) ASME B31.8S sections in their entirety. For ease of use, the 49 CFR 192.911 reference language is included immediately below with the respective ASME B31.8S language for each section following.

2.6.3 CFR Reference: 192.911 What Are the Elements of an Integrity Management Program?

2.6.3.1 CFR Language: 192.911, 192.911(i), 192.911(k), 192.911(l), 192.911(m)

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.)

2.6.3.2 ASME Standard Language

The CFR references ASME B31.8S “Supplement to B31.8 on Managing System Integrity of Gas Pipelines”, Sections 9, 10 11, and 12. For user convenience, Section 9, 10, 11 and 12 of B31.83 has been included below.

2.6.3.2.1 Performance Plan (B31.8S – 9)

2.6.3.2.1.1 Introduction (B31.8S - 9.1)

This section provides the performance plan requirements that apply to both prescriptive- and performance-based integrity management programs. Integrity management plan evaluations shall be performed at least annually to provide a continuing measure of integrity management program effectiveness over time. Such evaluations should consider both threat-specific and aggregate improvements. Threat-specific evaluations may apply to a particular area of concern, while overall measures apply to all pipelines under the integrity management program.

Program evaluation will help an operator answer the following questions:
(a) Were all integrity management program objectives accomplished?
(b) Were pipeline integrity and safety effectively improved through the integrity management program?

2.6.3.2.1.2 Performance Measures Characteristics (B31.8S - 9.2)

Performance measures focus attention on the integrity management program results that demonstrate improved safety has been attained. The measures provide an indication of effectiveness, but are not absolute. Performance measure evaluation and trending can also lead to recognition of unexpected results that may include the recognition of threats not previously identified. All performance measures shall be simple, measurable, attainable, relevant, and permit timely evaluations. Proper selection and evaluation of performance measures is an essential activity in determining integrity management program effectiveness.

Performance measures should be selected carefully to ensure that they are reasonable program effectiveness indicators. Change shall be monitored so the measures will remain effective over time as the plan matures. The time required to obtain sufficient data for analysis shall also be considered when selecting performance measures. Methods shall be implemented to permit both short- and long-term performance measure evaluations. Integrity management program performance measures can generally be categorized into groups.

Process or Activity Measures. (B31.8S - 9.2.1)

Process or activity measures can be used to evaluate prevention or mitigation activities. These measures determine how well an operator is implementing various elements of the integrity management program. Measures relating to process or activity shall be selected carefully to permit performance evaluation within a realistic time frame.

Operational Measures. (B31.8S - 9.2.2)

Operational measures include operational and maintenance trends that measure how well the system is responding to the integrity management program. An example of such a measure might be the changes in corrosion rates due to the implementation of a more effective cathodic protection (CP) program. The number of third-party pipeline hits after the implementation of prevention activities, such as improving the excavation notification process within the system, is another example.

Direct Integrity Measures. (B31.8S - 9.2.3)

Direct integrity measures include leaks, ruptures, injuries, and fatalities. In addition to the above categories, performance measures can also be categorized as leading measures or lagging measures. Lagging measures are reactive in that they provide an indication of past integrity management program performance. Leading measures are proactive; they provide an indication of how the plan may be expected to perform. Several examples of performance measures classified as described are illustrated in Figure 2-3.

2.6.3.2.1.3 Performance Measurement Methodology (B31.8S - 9.3)

An operator can evaluate a system's integrity management program performance within their own system and also by comparison with other systems on an industry-wide basis.

2.6.3.2.1.4 Performance Measurement: Intrasystem (B31.8S - 9.4)

(a) Performance metrics shall be selected and applied on a periodic basis for the evaluation of both prescriptive- and performance-based integrity management programs. Such metrics shall be suitable for evaluation of local and threat-specific conditions, and for evaluation of overall integrity management program performance.

(b) For operators implementing prescriptive programs, performance measurement shall include all of the threat-specific metrics for each threat in Subsection 2.6.5.4.2 (see Figure 2-4). Additionally, the following overall program measurements shall be determined and documented:

  (1) number of miles (kilometers) of pipeline inspected versus program requirements [the total miles (kilometers) of pipeline inspected during the reporting period including pipeline miles (kilometers) that were inspected as part of the integrity management plan but were not required to be inspected.]

  (2) number of immediate repairs completed as a result of the integrity management inspection program. (The total number of immediate actionable anomaly repairs made to a pipeline as a consequence of the integrity management plan inspections, anywhere on the pipeline. Only repairs physically made to the pipe are considered repairs. For this metric, coating repairs are not considered repairs. Each

actionable anomaly repaired shall be counted when a repair method is used that repairs multiple anomalies in a single repair area.)

(3) number of scheduled repairs completed as a result of the integrity management inspection program. [The total number of scheduled actionable anomaly repairs. See explanation for (2).]

(4) number of leaks, failures, and incidents (classified by cause)

(c) For operators implementing performance-based programs, the threat-specific metrics shown in Subsection 2.6.5.4.2 shall be considered, although others may be used that are more appropriate to the specific performance-based program. In addition to the four metrics above, the operator should choose three or four metrics that measure the effectiveness of the performance-based program. Figure 2-5 provides a suggested list; however, the operator may develop their own set of metrics. It may be appropriate and useful for operators to normalize the findings, events, and occurrences listed in Figure 2-5 utilizing normalization factors meaningful to the operator for that event and their system, and that would help them evaluate trends. Such normalization factors may include covered pipeline length, number of customers, time, or a combination of these or others. Since performance-based inspection intervals will be utilized in a performance-based integrity management program, it is essential that sufficient metric data be collected to support those inspection intervals. Program evaluation shall be performed on at least an annual basis.

(d) In addition to performance metric data collected directly from segments covered by the integrity management program, internal benchmarking can be conducted that may compare a segment against another adjacent segment or those from a different area of the same pipeline system. The information obtained may be used to evaluate the effectiveness of prevention activities, mitigation techniques, or performance validation. Such comparisons can provide a basis to substantiate metric analyses and identify areas for improvements in the integrity management program.

(e) A third technique that will provide effective information is internal auditing. Operators shall conduct periodic audits to validate the effectiveness of their integrity management programs and ensure that they have been conducted in accordance with the written plan. An audit frequency shall be established, considering the established performance metrics and their particular time base in addition to changes or modifications made to the integrity management program as it evolves. Audits may be performed by internal staff, preferably by personnel not directly involved in the administration of the integrity management program, or other resources. A list of essential audit items is provided below as a starting point in developing a company audit program.

(1) A written integrity management policy and program for all the elements in Figure 2-7 shall be in place.

(2) Written integrity management plan procedures and task descriptions are up to date and readily available.

(3) Activities are performed in accordance with the plan.

(4) A responsible individual has been assigned for each element.

(5) Appropriate references are available to responsible individuals.

(6) Individuals have received proper qualification, which has been documented.

(7) The integrity management program meets the requirements of this document.

(8) Required activities are documented.

(9) Action items or nonconformances are closed in a timely manner.

(10) The risk criteria used have been reviewed and documented.

(11) Prevention, mitigation, and repair criteria have been established, met, and documented.

(f) Data developed from program specific performance metrics, results of internal benchmarking, and audits shall be used to provide an effective basis for evaluation of the integrity management program.

Figure 2-3: Performance Measures (B31.8S - Table 9.2.3-1)

Measurement Category	Lagging Measures	Leading Measures
Process/activity measures	Pipe damage found per location excavated	Number of excavation notification requests, number of patrol detects
Operational measures	Number of significant ILI corrosion anomalies	New rectifiers and ground beds installed, CP current demand change, reduced CIS fault detects
Direct integrity measures	Leaks per mile (km) in an integrity management program	Change in leaks per mile (km)

Figure 2-4: Performance Metrics (B31.8S - Table 9.4(b)-1)

Threats	Performance Metrics for Prescriptive Programs
External corrosion	Number of hydrostatic test failures caused by external corrosion Number of repair actions taken due to in-line inspection results Number of repair actions taken due to direct assessment results Number of external corrosion leaks
Internal corrosion	Number of hydrostatic test failures caused by internal corrosion Number of repair actions taken due to in-line inspection results Number of repair actions taken due to direct assessment results Number of internal corrosion leaks
Stress corrosion cracking	Number of in-service leaks or failures due to SCC Number of repair replacements due to SCC Number of hydrostatic test failures due to SCC
Manufacturing	Number of hydrostatic test failures caused by manufacturing defects Number of leaks due to manufacturing defects
Construction	Number of leaks or failures due to construction defects Number of girth welds/couplings reinforced/removed Number of wrinkle bends removed Number of wrinkle bends inspected Number of fabrication welds repaired/removed
Equipment	Number of regulator valve failures Number of relief valve failures Number of gasket or O-ring failures Number of leaks due to equipment failures Number of block valve failures
Third-party damage	Number of leaks or failures caused by third-party damage Number of leaks or failures caused by previously damaged pipe Number of leaks or failures caused by vandalism Number of repairs implemented as a result of third-party damage prior to a leak or failure
Incorrect operations	Number of leaks or failures caused by incorrect operations Number of audits/reviews conducted Number of findings per audit/review, classified by severity
Weather related and outside forces	Number of leaks that are weather related or due to outside force Number of repair, replacement, or relocation actions due to weather-related or outside-force threats

Figure 2-5: Overall Performance Measures (B31.8S - Table 9.4(c)-1)

Miles (km) inspected vs. integrity management program requirement
Jurisdictional reportable incidents/safety-related conditions per unit of time
Fraction of system included in the integrity management program

Number of anomalies found requiring repair or mitigation
Number of leaks repaired
Number of pressure test failures and test pressures [psi (kPa) and % SMYS]

Number of third-party damage events, near misses, damage detected
Risk or probability of failure reduction achieved by integrity management program
Number of unauthorized crossings

Number of right-of-way encroachments:
- Number of pipeline hits by third parties due to lack of notification as locate request through the one-call process
- Number of aerial/ground patrol incursion detections
- Number of excavation notifications received and their disposition

Integrity management program costs

2.6.3.2.1.5 Performance Measurement: Industry Based (B31.8S - 9.5)

In addition to intrasystem comparisons, external comparisons can provide a basis for performance measurement of the integrity management program. This can include comparisons with other pipeline operators, industry data sources, and jurisdictional data sources. Benchmarking with other gas pipeline operators can be useful; however, any performance measure or evaluation derived from such sources shall be carefully evaluated to ensure that all comparisons made are valid. Audits conducted by outside entities can also provide useful evaluation data.

2.6.3.2.1.6 Performance Improvement (B31.8S - 9.6)

The results of the performance measurements and audits shall be utilized to modify the integrity management program as part of a continuous improvement process. Internal and external audit results are performance measures that should be used to evaluate effectiveness in addition to other measures stipulated in the integrity management program. Recommendations for changes and/or improvements to the integrity management program shall be based on analysis of the performance measures and audits. The results, recommendations, and resultant changes made to the integrity management program shall be documented.

2.6.3.2.2 Communication Plan (B31.8S - 10)

2.6.3.2.2.1 General (B31.8S - 10.1)

The operator shall develop and implement a communications plan in order to keep appropriate company personnel, jurisdictional authorities, and the public informed about their integrity management efforts and the results of their integrity management activities. The information may be communicated as part of other required communications.

Some of the information should be communicated routinely. Other information may be communicated upon request. Use of industry, jurisdictional, and company websites may be an effective way to conduct these communication efforts.

Communications should be conducted as often as necessary to ensure that appropriate individual s and authorities have current information about the operator's system and their integrity management efforts. It is recommended that communications take place periodically and as often as necessary to communicate significant changes to the integrity management plan. API Recommended Practice 1162, Public Awareness Programs for Pipeline Operators, provides additional guidance.

2.6.3.2.2.2 External Communications (B31.8S - 10.2)

The following items should be considered for communication to the various interested parties, as outlined below:

(a) Landowners and Tenants Along the Rights-of-Way
- *(1)* company name, location, and contact information
- *(2)* general location information and where more specific location information or maps can be obtained
- *(3)* commodity transported
- *(4)* how to recognize, report, and respond to a leak
- *(5)* contact phone numbers, both routine and emergency
- *(6)* general information about the pipeline operator's prevention, integrity measures, and emergency preparedness, and how to obtain a summary of the integrity management plan
- *(7)* damage prevention information, including excavation notification numbers, excavation notification center requirements, and who to contact if there is any damage

(b) Public Officials Other Than Emergency Responders
- *(1)* periodic distribution to each municipality of maps and company contact information
- *(2)* summary of emergency preparedness and integrity management program

(c) Local and Regional Emergency Responders
- *(1)* operator should maintain continuing liaison with all emergency responders, including local emergency planning commissions, regional and area planning committees, jurisdictional emergency planning offices, etc.
- *(2)* company name and contact numbers, both routine and emergency
- *(3)* local maps
- *(4)* facility description and commodity transported
- *(5)* how to recognize, report, and respond to a leak
- *(6)* general information about the operator's prevention and integrity measures, and how to obtain a summary of the integrity management plan
- *(7)* station locations and descriptions
- *(8)* summary of operator's emergency capabilities
- *(9)* coordination of operator's emergency preparedness with local officials

(d) General Public
- *(1)* information regarding operator's efforts to support excavation notification and other damage prevention initiatives
- *(2)* company name, contact, and emergency reporting information, including general business contact

It is expected that some dialogue may be necessary between the operator and the public in order to convey the operator's confidence in the integrity of the pipeline, as well as to convey the operator's expectations of the public as to where they can help maintain integrity. Such opportunities should be welcomed in order to help protect assets, people, and the environment.

2.6.3.2.2.3 Internal Communications (B31.8S - 10.3)

Operator management and other appropriate operator personnel must understand and support the integrity management program. This should be accomplished through the development and implementation of an internal communications aspect of the plan. Performance measures reviewed on a periodic basis and resulting adjustments to the integrity management program should also be part of the internal communications plan.

2.6.3.2.3 Management of Change Plan (B31.8S - 11)

(a) Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural, and organizational changes to the system, whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

A management of change process includes the following:

(1) reason for change
(2) authority for approving changes
(3) analysis of implications
(4) acquisition of required work permits
(5) documentation
(6) communication of change to affected parties
(7) time limitations
(8) qualification of staff

(b) The operator shall recognize that system changes can require changes in the integrity management program and, conversely, results from the program can cause system changes. The following are examples that are gas-pipeline specific, but are by no means all-inclusive.

(1) If a change in land use would affect either the consequence of an incident, such as increases in population near the pipeline, or a change in likelihood of an incident, such as subsidence due to underground mining, the change must be reflected in the integrity management plan and the threats reevaluated accordingly.

(2) If the results of an integrity management program inspection indicate the need for a change to the system, such as changes to the CP program or, other than temporary, reductions in operating pressure, these shall be communicated to operators and reflected in an updated integrity management program.

(3) If an operator decides to increase pressure in the system from its historical operating pressure to, or closer to, the allowable MAOP, that change shall be reflected in the integrity plan and the threats shall be reevaluated accordingly.

(4) If a line has been operating in a steady-state mode and a new load on the line changes the mode of operation to a more cyclical load (e.g., daily changes in operating pressure), fatigue shall be considered in each of the threats where it applies as an additional stress factor.

(c) Along with management, the review procedure should require involvement of staff that can assess safety impact and, if necessary, suggest controls or modifications. The operator shall have the flexibility to maintain continuity of operation within established safe operating limits.

(d) Management of change ensures that the integrity management process remains viable and effective as changes to the system occur and/or new, revised, or corrected data becomes available. Any change to equipment or procedures has the potential to affect pipeline integrity. Most changes, however small, will have a consequent effect on another aspect of the system. For example, many equipment changes will require a corresponding technical or procedural change. All changes shall be identified and reviewed before implementation. Management of change procedures provides a means of maintaining order during periods of change in the system and helps to preserve confidence in the integrity of the pipeline.

(e) In order to ensure the integrity of a system, a documented record of changes should be developed and maintained. This information will provide a better understanding of the system and possible threats to its integrity. It should include the process and design information both before and after the changes were put into place.

(f) Communication of the changes carried out in the pipeline system to any affected parties is imperative to the safety of the system. As provided in Section 10, communications regarding the integrity of the pipeline should be conducted periodically. Any changes to the system should be included in the information provided in communication from the pipeline operator to affected parties.

(g) System changes, particularly in equipment, may require qualification of personnel for the correct operation of the new equipment. In addition, refresher training should be provided to ensure that facility personnel understand and adhere to the facility's current operating procedures.

(h) The application of new technologies in the integrity management program and the results of such applications should be documented and communicated to appropriate staff and stakeholders.

2.6.3.2.4 Quality Control Plan (B31.8S - 12)

This section describes the quality control activities that shall be part of an acceptable integrity management program.

2.6.3.2.4.1 General (B31.8S - 12.1)

Quality control as defined for this Code [ASME B31.8S] is the "documented proof that the operator meets all the requirements of their integrity management program." Pipeline operators that have a quality control program that meets or exceeds the requirements in this section can incorporate the integrity management program activities within their existing plan. For those operators who do not have a quality program, this section outlines the basic requirements of such a program.

2.6.3.2.4.2 Quality Management Control (B31.8S - 12.2)

(a) Requirements of a quality control program include documentation, implementation, and maintenance. The following six activities are usually required:
- *(1)* identify the processes that will be included in the quality program
- *(2)* determine the sequence and interaction of these processes
- *(3)* determine the criteria and methods needed to ensure that both the operation and control of these processes are effective
- *(4)* provide the resources and information necessary to support the operation and monitoring of these processes
- *(5)* monitor, measure, and analyze these processes
- *(6)* implement actions necessary to achieve planned results and continued improvement of these processes

(b) Specifically, activities to be included in the quality control program are as follows:
- *(1)* the operator shall determine the documentation required and include it in the quality program. These documents shall be controlled and maintained at appropriate locations for the duration of the program. Examples of documented activities include risk assessments, the integrity management plan, integrity management reports, and data documents.
- *(2)* the responsibilities and authorities under this program shall be clearly and formally defined.
- *(3)* results of the integrity management program and the quality control program shall be reviewed at predetermined intervals, making recommendations for improvement.
- *(4)* the personnel involved in the integrity management program shall be competent, aware of the program and all of its activities, and be qualified to execute the activities within the program. Documentation of such competence, awareness, and qualification, and the processes for their achievement, shall be part of the quality control plan.
- *(5)* the operator shall determine how to monitor the integrity management program to show that it is being implemented according to plan and document these steps. These control points, criteria, and/or performance metrics shall be defined.

- *(6)* Periodic internal audits or independent third-party reviews of the integrity management program and its quality plan are required.
- *(7)* corrective actions to improve the integrity management program or quality plan shall be documented and the effectiveness of their implementation monitored.

(c) When an operator chooses to use outside resources to conduct any process (for example, pigging) that affects the quality of the integrity management program, the operator shall ensure control of such processes and document them within the quality program.

2.6.4 CFR Reference: 192.913 When May an Operator Deviate its Program from Certain Requirements of this Subpart?

2.6.4.1 CFR Language: 192.913(a), 192.913(b)(1)

(a) *General* - ASME/ANSI B31.8S (incorporated by reference, see § 192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

(b) *Exceptional performance* - An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

- *(1)* To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements—
  - *(i)* A comprehensive process for risk analysis;
  - *(ii)* All risk factor data used to support the program;
  - *(iii)* A comprehensive data integration process;
  - *(iv)* A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;
  - *(v)* A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;
  - *(vi)* A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;
  - *(vii)* Semi-annual performance measures beyond those required in § 192.945 that are part of the operator's performance plan (see § 192.911(i)). An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with § 192.951; and
  - *(viii)* An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.
- *(2)* In addition to the requirements for the performance-based plan, an operator must—
  - *(i)* Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.
  - *(ii)* Remediate all anomalies identified in the more recent assessment according to the requirements in § 192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

(c) *Deviation* - Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances.

(1) The time frame for reassessment as provided in § 192.939 except that reassessment by some method allowed under this subpart (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in § 192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.
[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004]

2.6.4.2 ASME Standard Language

49 CFR 192.913(a) and 49 CFR 192.913(b)(1) do not contain direct references to ASME B31.8S; however, segments of ASME B31.8S Sections 5, 6, and 9 are applicable. For user convenience: ASME B31.8S Section 5 language may be found in Subsection 2.6.5.6.1; ASME B31.8S Section 6 language may be found in Subsection 2.6.5.2.2; and ASME B31.8S Section 9 language may be found in Subsection 2.6.3.2.1.

2.6.5 CFR Reference: 192.917 How Does an Operator Identify Potential Threats to Pipeline Integrity and Use the Threat Identification in its Integrity Program?

2.6.5.1 CFR Language 192.917(a)

(a) *Threat identification*. An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

2.6.5.2 ASME Standard Language

The CFR references ASME B31.8S “Supplement to B31.8 on Managing System Integrity of Gas Pipelines” Section 2. For user convenience, Section 2 of B31.8S has been included below.

2.6.5.2.1 Integrity Management Program Overview (B31.8S - 2)

2.6.5.2.1.1 General (B31.8S - 2.1)

This section describes the required elements of an integrity management program. These program elements collectively provide the basis for a comprehensive, systematic, and integrated integrity management program. The program elements depicted in Figure 2-6 are required for all integrity management programs.

This Code [ASME B31.8S] requires that the operator document how its integrity management program will address the key program elements. This Code [ASME B31.8S] utilizes recognized industry practices for developing an integrity management program.

The process shown in Figure 2-7 provides a common basis to develop (and periodically reevaluate) an operator-specific program. In developing the program, pipeline operators shall consider their companies' specific integrity management goals and objectives, and then apply the processes to ensure that these goals are achieved. This Code [ASME B31.8S] details two approaches to integrity management: a prescriptive method and a performance-based method.

The prescriptive integrity management method requires the least amount of data and analysis, and can be successfully implemented by following the steps provided in this Code [B31.8S] and Nonmandatory Appendix A. The prescriptive method incorporates expected worst-case indication growth to establish intervals between successive integrity assessments in exchange for reduced data requirements and less-extensive analysis.

Figure 2-6: Integrity Management Program Elements (B31.8S Fig. 2.1-1)

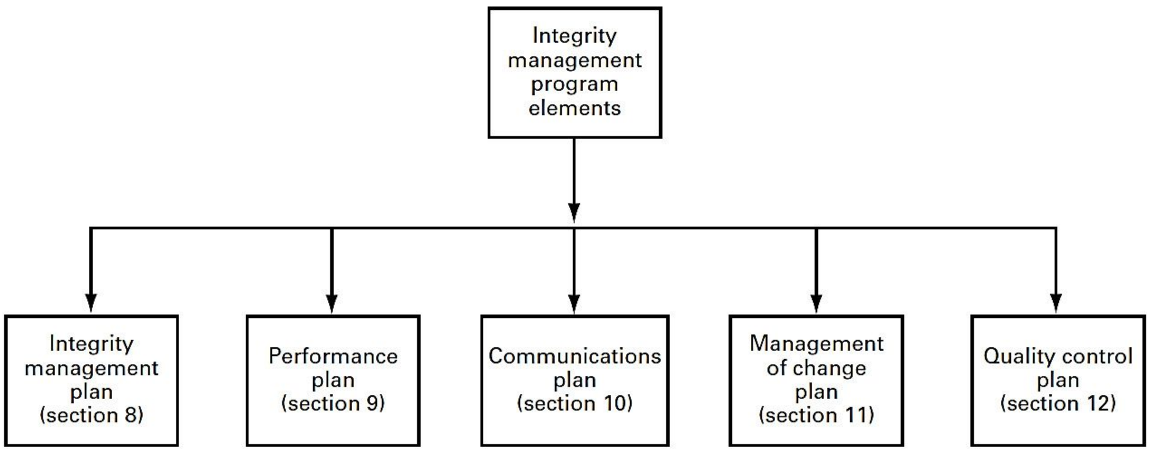
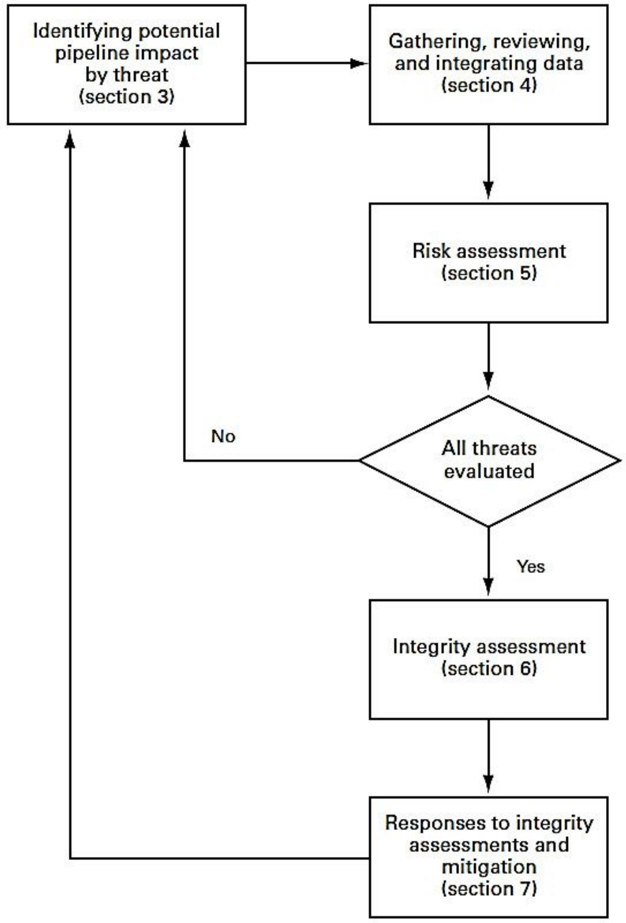


Figure 2-7: Integrity Management Plan Process Flow Diagram (B31.8S - Fig. 2.1-2)



The performance-based integrity management method requires more knowledge of the pipeline, and consequently more data-intensive risk assessments and analyses can be completed. The resulting performance-based integrity management program can contain more options for inspection intervals, inspection tools, mitigation, and prevention methods. The results of the performance-based method must meet or exceed the results of the prescriptive method. A performance-based program cannot be implemented until the operator has performed adequate integrity assessments that provide the data for a performance-based program. A performance-based integrity management program shall include the following in the integrity management plan:

(a) a description of the risk analysis method employed
(b) documentation of all of the applicable data for each segment and where it was obtained
(c) a documented analysis for determining integrity assessment intervals and mitigation (repair and prevention) methods
(d) a documented performance matrix that, in time, will confirm the performance-based options chosen by the operator

The processes for developing and implementing a performance-based integrity management program are included in this Code [B31.8S].

There is no single "best" approach that is applicable to all pipeline systems for all situations. This Code [B31.8S] recognizes the importance of flexibility in designing integrity management programs and provides alternatives commensurate with this need. Operators may choose either a prescriptive- or a performance-based approach for their entire system, individual lines, segments, or individual threats. The program elements shown in Figure 2-6 are required for all integrity management programs.

The process of managing integrity is an integrated and iterative process. Although the steps depicted in Figure 2-7 are shown sequentially for ease of illustration, there is a significant amount of information flow and interaction among the different steps. For example, the selection of a risk assessment approach depends in part on what integrity-related data and information is available. While performing a risk assessment, additional data needs may be identified to more accurately evaluate potential threats. Thus, the data gathering and risk assessment steps are tightly coupled and may require several iterations until an operator has confidence that a satisfactory assessment has been achieved.

A brief overview of the individual process steps is provided in Subsection 2.6.5.2.1 as well as instructions to the more specific and detailed description of the individual elements that compose the remainder of this Code [B31.8S]. References to the specific detailed sections in this Code [B31.8S] are shown in Figure 2-6 and Figure 2-7.

2.6.5.2.1.2 Integrity Threat Classification (B31.8S - 2.2)

The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered. Gas pipeline incident data has been analyzed and classified by the Pipeline Research Committee International (PRCI) into 22 root causes. Each of the 22 causes represents a threat to pipeline integrity that shall be managed. One of the causes reported by operators is “unknown”; that is, no root cause or causes were identified. The remaining 21 threats have been grouped into nine categories of related failure types according to their nature and growth characteristics, and further delineated by three time-related defect types. The nine categories are useful in identifying potential threats. Risk assessment, integrity assessment, and mitigation activities shall be correctly addressed according to the time factors and failure mode grouping.

(a) Time-Dependent
- *(1)* external corrosion
- *(2)* internal corrosion
- *(3)* stress corrosion cracking

(b) Stable
- *(1)* Manufacturing-related defects
  - *(i)* defective pipe seam
  - *(ii)* defective pipe
- *(2)* Welding/fabrication related
  - *(i)* defective pipe girth weld (circumferential) including branch and T joints
  - *(ii)* defective fabrication weld
  - *(iii)* wrinkle bend or buckle
  - *(iv)* stripped threads/broken pipe/coupling failure
- *(3)* Equipment
  - *(i)* gasket O-ring failure
  - *(ii)* control/relief equipment malfunction
  - *(iii)* seal/pump packing failure
  - *(iv)* miscellaneous

(c) Time-Independent
- *(1)* Third party/mechanical damage
  - *(i)* damage inflicted by first, second, or third parties (instantaneous/immediate failure)
  - *(ii)* previously damaged pipe (such as dents and/or gouges) (delayed failure mode)
  - *(iii)* vandalism
- *(2)* Incorrect operational procedure

(3) Weather-related and outside force
  (i) cold weather
  (ii) lightning
  (iii) heavy rains or floods
  (iv) earth movements

The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered. An example of such an interaction is corrosion at a location that also has third-party damage.

The operator shall consider each threat individually or in the nine categories when following the process selected for each pipeline system or segment. The prescriptive approach delineated in Subsection 2.6.5.4.2 enables the operator to conduct the threat analysis in the context of the nine categories. All 21 threats shall be considered when applying the performance-based approach.

If the operational mode changes and pipeline segments are subjected to significant pressure cycles, pressure differential, and rates of change of pressure fluctuations, fatigue shall be considered by the operator, including any combined effect from other failure mechanisms that are considered to be present, such as corrosion. A useful reference to help the operator with this consideration is GRI 04-0178, "Effect of Pressure Cycles on Gas Pipelines."

2.6.5.2.1.3 The Integrity Management Process (B31.8S - 2.3)

The integrity management process depicted in Figure 2-7 is described below.

Identify Potential Pipeline Impact by Threat (B31.8S - 2.3.1)

This program element involves the identification of potential threats to the pipeline, especially in areas of concern. Each identified pipeline segment shall have the threats considered individually or by the nine categories. See Subsection 2.6.5.2.1.2.

Gathering, Reviewing, and Integrating Data (B31.8S - 2.3.2)

The first step in evaluating the potential threats for a pipeline system or segment is to define and gather the necessary data and information that characterize the segments and the potential threats to that segment. In this step, the operator performs the initial collection, review, and integration of relevant data and information that is needed to understand the condition of the pipe; identify the location-specific threats to its integrity; and understand the public, environmental, and operational consequences of an incident. The types of data to support a risk assessment will vary depending on the threat being assessed. Information on the operation, maintenance, patrolling, design, operating history, and specific failures and concerns that are unique to each system and segment will be needed. Relevant data and information also include those conditions or actions that affect defect growth (e.g., deficiencies in cathodic protection), reduce pipe properties (e.g., field welding), or relate to the introduction of new defects (e.g., excavation work near a pipeline). Subsection 2.6.1.2.1 provides information on consequences. Subsection 2.6.5.4.1 provides details for data gathering, review, and integration of pipeline data.

Risk Assessment (B31.8S - 2.3.3)

In this step, the data assembled from the previous step are used to conduct a risk assessment of the pipeline system or segments. Through the integrated evaluation of the information and data collected in the previous step, the risk assessment process identifies the location-specific events and/or conditions that could lead to a pipeline failure, and provides an understanding of the likelihood and consequences (see Subsection 2.6.1.2.1) of an event. The output of a risk assessment should include the nature and location of the most significant risks to the pipeline.

Under the prescriptive approach, available data are compared to prescribed criteria (see Subsection 2.6.5.4.2). Risk assessments are required in order to rank the segments for integrity assessments. The performance-based approach relies on detailed risk assessments. There are a variety of risk assessment methods that can be applied based on the available data and the nature of the threats. The operator should tailor the method to meet the needs of the system. An initial screening risk assessment can be beneficial in terms of focusing resources on the most important areas to be addressed and where additional data may be of value. Subsection 2.6.5.6.1 provides details on the criteria selection for the prescriptive approach and risk assessment for the performance-based approach. The results of this step enable the operator to prioritize the pipeline segments for appropriate actions that will be defined in the integrity management plan. Subsection 2.6.5.4.2 provides the steps to be followed for a prescriptive program.

Integrity Assessment (B31.8S - 2.3.4)

Based on the risk assessment made in the previous step, the appropriate integrity assessments are selected and conducted. The integrity assessment methods are in-line inspection, pressure testing, direct assessment, or other integrity assessment methods, as defined in Subsection 2.6.5.2.2.5. Integrity assessment method selection is based on the threats that have been identified. More than one integrity assessment method may be required to address all the threats to a pipeline segment.

A performance-based program may be able, through appropriate evaluation and analysis, to determine alternative courses of action and time frames for performing integrity assessments. It is the operators' responsibility to document the analyses justifying the alternative courses of action or time frames. Subsection 2.6.5.2.2 provides details on tool selection and inspection.

Data and information from integrity assessments for a specific threat may be of value when considering the presence of other threats and performing risk assessment for those threats. For example, a dent may be identified when running a magnetic flux leakage (MFL) tool while checking for corrosion. This data element should be integrated with other data elements for other threats, such as third-party or construction damage.

Indications that are discovered during inspections shall be examined and evaluated to determine if they are actual defects or not. Indications may be evaluated using an appropriate examination and evaluation tool. For local internal or external metal loss, ASME B31G or similar analytical methods may be used.

Responses to Integrity Assessment, Mitigation (Repair and Prevention), and Setting Inspection Intervals (B31.8S - 2.3.5)

In this step, schedules to respond to indications from inspections are developed. Repair activities for the anomalies discovered during inspection are identified and initiated. Repairs are performed in accordance with accepted industry standards and practices.

Prevention practices are also implemented in this step. For third-party damage prevention and low-stress pipelines, mitigation may be an appropriate alternative to inspection. For example, if damage from excavation was identified as a significant risk to a particular system or segment, the operator may elect to conduct damage-prevention activities such as increased public communication, more effective excavation notification systems, or increased excavator awareness in conjunction with inspection.

The mitigation alternatives and implementation timeframes for performance-based integrity management programs may vary from the prescriptive requirements. In such instances, the performance-based analyses that lead to these conclusions shall be documented as part of the integrity management program. Subsection 2.6.11.6.1 provides details on repair and prevention techniques.

Update, Integrate, and Review Data (B31.8S - 2.3.6)

After the initial integrity assessments have been performed, the operator has improved and updated information about the condition of the pipeline system or segment. This information shall be retained and added to the database of information used to support future risk assessments and integrity assessments. Furthermore, as the system continues to operate, additional operating, maintenance, and other information is collected, thus expanding and improving the historical database of operating experience.

Reassess Risk (B31.8S - 2.3.7)

Risk assessment shall be performed periodically within regular intervals, and when substantial changes occur to the pipeline. The operator shall consider recent operating data, consider changes to the pipeline system design and operation, analyze the impact of any external changes that may have occurred since the last risk assessment, and incorporate data from risk assessment activities for other threats. The results of integrity assessment, such as internal inspection, shall also be factored into future risk assessments, to ensure that the analytical process reflects the latest understanding of pipe condition.

2.6.5.2.1.4 Integrity Management Program (B31.8S - 2.4)

The essential elements of an integrity management program are depicted in Figure 2-6 and are described below.

Integrity Management Plan (B31.8S - 2.4.1)

The integrity management plan is the outcome of applying the process depicted in Figure 2-6 and discussed in Subsection 2.6.5.2.3. The plan is the documentation of the execution of each of the steps and the supporting analyses that are conducted. The plan shall include prevention, detection, and mitigation practices. The plan shall also have a schedule established that considers the timing of the practices deployed. Those systems or segments with the highest risk should be addressed first. Also, the plan shall consider those practices that may address more than one threat. For instance, a hydrostatic test may demonstrate a pipeline's integrity for both time-dependent threats like internal and external corrosion as well as static threats such as seam weld defects and defective fabrication welds.

A performance-based integrity management plan contains the same basic elements as a prescriptive plan. A performance-based plan requires more detailed information and analyses based on more extensive knowledge about the pipeline. This Code [ASME B31.8S] does not require a specific risk analysis model, only that the risk model used can be shown to be effective. The detailed risk analyses will provide a better understanding of integrity, which will enable an operator to have a greater degree of flexibility in the timing and methods for the implementation of a performance-based integrity management plan. Section 2.6.5.2.3 provides details on plan development.

The plan shall be periodically updated to reflect new information and the current understanding of integrity threat s. As new risks or new manifest at ions of previously known risks are identified, additional mitigative actions to address these risks shall be performed, as appropriate. Furthermore, the updated risk assessment results shall also be used to support scheduling of future integrity assessments.

Performance Plan (B31.8S - 2.4.2)

The operator shall collect performance information and periodically evaluate the success of its integrity assessment techniques, pipeline repair activities, and the mitigative risk control activities. The operator shall also evaluate the effectiveness of its management systems and processes in supporting sound integrity management decisions. Subsection 2.6.3.2.1 provides the information required for developing performance measures to evaluate program effectiveness. The application of new technologies into the integrity management program shall be evaluated for further use in the program.

Communications Plan (B31.8S - 2.4.3)

The operator shall develop and implement a plan for effective communications with employees, the public, emergency responders, local officials, and jurisdictional authorities in order to keep the public informed about their integrity management efforts. This plan shall provide information to be communicated to each stakeholder about the integrity plan and the results achieved. Subsection 2.6.3.2.2 provides further information about communications plans.

Management of Change Plan (B31.8S - 2.4.4)

Pipeline systems and the environment in which they operate are seldom static. A systematic process shall be used to ensure that, prior to implementation, changes to the pipeline system design, operation, or maintenance are evaluated for their potential risk impacts, and to ensure that changes to the environment in which the pipeline operates are evaluated. After these changes are made, they shall be incorporated, as appropriate, into future risk assessments to ensure that the risk assessment process addresses the systems as currently configured, operated, and maintained. The results of the plan's mitigative activities should be used as a feedback for systems and facilities design and operation. Subsection 2.6.3.2.3 discusses the important aspects of managing changes as they relate to integrity management.

Quality Control Plan (B31.8S - 2.4.5)

Subsection 2.6.3.2.4 discusses the evaluation of the integrity management program for quality control purposes. That section outlines the necessary documentation for the integrity management program. The section also discusses auditing of the program, including the processes, inspections, mitigation activities, and prevention activities.

2.6.5.2.2 Integrity Assessment (B31.8S - 6)

2.6.5.2.2.1 General (B31.8S – 6.1)

Based on the priorities determined by risk assessment, the operator shall conduct integrity assessments using the appropriate integrity assessment methods. The integrity assessment methods that can be used are inline inspection, pressure testing, direct assessment, or other methodologies provided in Subsection 2.6.5.2.2.5. The integrity assessment method is based on the threats to which the segment is susceptible. More than one method and/or tool may be required to address all the threats in a pipeline segment. Conversely, inspection using any of the integrity assessment methods may not be the appropriate action for the operator to take for certain threats. Other actions, such as prevention, may provide better integrity management results.

Subsection 2.6.5.2.1 provides a listing of threats by three groups: time-dependent, stable, and time-independent. Time-dependent threats can typically be addressed by utilizing any one of the integrity assessment methods discussed in this section. Stable threats, such as defects that occurred during manufacturing, can typically be addressed by pressure testing, while construction and equipment threats can typically be addressed by examination and evaluation of the specific piece of equipment, component, or pipe joint. Random threats typically cannot be addressed through use of any of the integrity assessment methods discussed in this section, but are subject to the prevention measures discussed in Subsection 2.6.11.6.1.

Use of a particular integrity assessment method may find indications of threats other than those that the assessment was intended to address. For example, the third-party damage threat is usually best addressed by implementation of prevention activities; however, an in-line inspection tool may indicate a dent in the top half of the pipe. Examination of the dent may be an appropriate action in order to determine if the pipe was damaged due to third-party activity.

It is important to note that some of the integrity assessment methods discussed in Subsection 2.6.5.2.2 only provide indications of defects. Examination using visual inspection and a variety of nondestructive examination (NDE) techniques are required, followed by evaluation of these inspection results in order to characterize the defect. The operator may choose to go directly to examination and evaluation for the entire length of the pipeline segment being assessed, in lieu of conducting inspections. For example, the operator may wish to conduct visual examination of aboveground piping for the external corrosion threat. Since the pipe is accessible for this technique and external corrosion can be readily evaluated, performing in-line inspection is not necessary.

2.6.5.2.2.2 Pipeline In-Line Inspection (B31.8S – 6.2)

In-line inspection (ILI) is an integrity assessment method used to locate and preliminarily characterize indications, such as metal loss or deformation, in a pipeline. The effectiveness of the ILI tool used depends on the condition of the specific pipeline section to be inspected and how well the tool matches the requirements set by the inspection objectives. API Standard 1163, In-Line Inspection Systems Qualification, provides additional guidance on pipeline in-line inspection. The following paragraphs discuss the use of ILI tools for certain threats.

Metal Loss Tools for the Internal and External Corrosion Threat (B31.8S – 6.2.1)

For these threats, the following tools can be used. Their effectiveness is limited by the technology the tool employs.

(a) Magnetic Flux Leakage, Standard Resolution Tool - This is better suited for detection of metal loss than for sizing. Sizing accuracy is limited by sensor size. It is sensitive to certain metallurgical defects, such as scabs and slivers. It is not reliable for detection or sizing of most defects other than metal loss, and not reliable for detection or sizing of axially aligned metal-loss defects. High inspection speeds degrade sizing accuracy.

(b) Magnetic Flux Leakage, High Resolution Tool - This provides better sizing accuracy than standard resolution tools. Sizing accuracy is best for geometrically simple defect shapes. Sizing accuracy degrades where pits are present or defect geometry becomes complex. There is some ability to detect defects other than metal loss, but ability varies with defect geometries and characteristics. It is not generally reliable for axially aligned defects. High inspection speeds degrade sizing accuracy.

(c) Ultrasonic Compression Wave Tool - This usually requires a liquid couplant. It provides no detection or sizing capability where return signals are lost, which can occur in defects with rapidly changing profiles, some bends, and when a defect is shielded by a lamination. It is sensitive to debris and deposits on the inside pipe wall. High speeds degrade axial sizing resolution.

(d) Ultrasonic Shear Wave Tool - This requires a liquid couplant or a wheel-coupled system. Sizing accuracy is limited by the number of sensors and the complexity of the defect. Sizing accuracy is degraded by the presence of inclusions and impurities in the pipe wall. High speeds degrade sizing resolution.

(e) Transverse Flux Tool - This is more sensitive to axially aligned metal-loss defects than standard and high resolution MFL tools. It may also be sensitive to other axially aligned defects. It is less sensitive than standard and high resolution MFL tools to circumferentially aligned defects. It generally provides less sizing accuracy than high resolution MFL tools for most defect geometries. High speeds can degrade sizing accuracy.

Crack Detection Tools for the Stress Corrosion Cracking Threat (B31.8S – 6.2.2)

For this threat, the following tools can be used. Their effectiveness is limited by the technology the tool employs.

(a) Ultrasonic Shear Wave Tool - This requires a liquid couplant or a wheel-coupled system. Sizing accuracy is limited by the number of sensors and the complexity of the crack colony. Sizing accuracy is degraded by the presence of inclusions and impurities in the pipe wall. High inspection speeds degrade sizing accuracy and resolution.

(b) *Transverse Flux Tool* - This is able to detect some axially aligned cracks, not including stress corrosion cracking (SCC), but is not considered accurate for sizing. High inspection speeds can degrade sizing accuracy.

Metal Loss and Caliper Tools for Third-Party Damage and Mechanical Damage Threat (B31.8S – 6.2.3)

Dents and areas of metal loss are the only aspect of these threats for which ILI tools can be effectively used for detection and sizing.

Deformation or geometry tools are most often used for detecting damage to the line involving deformation of the pipe cross section, which can be caused by construction damage, dents caused by the pipe settling onto rocks, third-party damage, and wrinkles or buckles caused by compressive loading or uneven settlement of the pipeline.

The lowest-resolution geometry tool is the gaging pig or single-channel caliper-type tool. This type of tool is adequate for identifying and locating severe deformation of the pipe cross section. A higher resolution is provided by standard caliper tools that record a channel of data for each caliper arm, typically 10 or 12 spaced around the circumference. This type of tool can be used to discern deformation severity and overall shape aspects of the deformation. With some effort, it is possible to identify sharpness or estimate strains associated with the deformation using the standard caliper tool output. High-resolution tools provide the most detailed information about the deformation. Some also indicate slope or change in slope, which can be useful for identifying bending or settlement of the pipeline. Third-party damage that has rerounded under the influence of internal pressure in the pipe may challenge the lower limits of reliable detection of both the standard and high-resolution tools. There has been limited success identifying third-party damage using magnetic-flux leakage tools. MFL tools are not useful for sizing deformations.

All Other Threats (B31.8S – 6.2.4)

In-line inspection is typically not the appropriate inspection method to use for all other threats listed in Subsection 2.6.5.2.1.

Special Considerations for the Use of In-Line Inspection Tools (B31.8S – 6.2.5)

(a) The following shall also be considered when selecting the appropriate tool:
   (1) *Detection Sensitivity* - Minimum defect size specified for the ILI tool should be smaller than the size of the defect sought to be detected.
   (2) *Classification* - Classification allows differentiation among types of anomalies.
   (3) *Sizing Accuracy* - Sizing accuracy enables prioritization and is a key to a successful integrity management plan.
   (4) *Location Accuracy* - Location accuracy enables location of anomalies by excavation.
   (5) *Requirements for Defect Assessment* - Results of ILI have to be adequate for the specific operator's defect assessment program.

(b) Typically, pipeline operators provide answers to a questionnaire provided by the ILI vendor that should list all the significant parameters and characteristics of the pipeline section to be inspected. Some of the more import ant issues that should be considered are as follows:
   (1) *Pipeline Questionnaire* - The questionnaire pro- vides a review of pipe characteristics, such as steel grade, type of welds, length, diameter, wall thickness, elevation profiles, etc. Also, the questionnaire identifies any restrictions, bends, known ovalities, valves, unbarred tees, couplings, and chill rings the ILI tool may need to negotiate.
   (2) *Launchers and Receivers* - These items should be reviewed for suitability, since ILI tools vary in overall length, complexity, geometry, and maneuverability.
   (3) *Pipe Cleanliness* - The cleanliness can significantly affect data collection.
   (4) *Type of Fluid* - The type of phase — gas or liquid — affects the possible choice of technologies.
   (5) *Flow Rate, Pressure, and Temperature* - Flow rate of the gas will influence the speed of the ILI tool inspection. If speeds are outside of the normal ranges, resolution can be compromised. Total

time of inspection is dictated by inspection speed, but is limited by the total capacity of batteries and data storage available on the tool. High temperatures can affect tool operation quality and should be considered.

(6) *Product Bypass/Supplement* - Reduction of gas flow and speed reduction capability on the ILI tool may be a consideration in higher velocity lines. Conversely, the availability of supplementary gas where the flow rate is too low shall be considered.

(c) The operator shall assess the general reliability of the ILI method by looking at the following:

- *(1)* confidence level of the ILI method (e.g., probability of detecting, classifying, and sizing the anomalies)
- *(2)* history of the ILI method/tool
- *(3)* success rate/failed surveys
- *(4)* ability of the tool to inspect the full length and full circumference of the section
- *(5)* ability to indicate the presence of multiple cause anomalies

Generally, representatives from the pipeline operator and the ILI service vendor should analyze the goal and objective of the inspection, and match significant factors known about the pipeline and expected anomalies with the capabilities and performance of the tool. Choice of tool will depend on the specifics of the pipeline section and the goal set for the inspection. The operator shall outline the process used in the integrity management plan for the selection and implementation of the ILI inspections.

Examination and Evaluation (B31.8S – 6.2.6)

Results of in-line inspection only provide indications of defects, with some characterization of the defect. Screening of this information is required in order to determine the time frame for examination and evaluation. The time frame is discussed in Subsection 2.6.11.6.1.

Examination consists of a variety of direct inspection techniques, including visual inspection, inspections using NDE equipment, and taking measurements, in order to characterize the defect in confirmatory excavations where anomalies are detected. Once the defect is characterized, the operator must evaluate the defect in order to determine the appropriate mitigation actions. Mitigation is discussed in Subsection 2.6.11.6.1.

2.6.5.2.2.3 Pressure Testing (B31.8S – 6.3)

Pressure testing has long been an industry-accepted method for validating the integrity of pipelines. This integrity assessment method can be both a strength test and a leak test. Selection of this method shall be appropriate for the threats being assessed.

ASME B31.8 contains details on conducting pressure tests for both post-construction testing and for subsequent testing after a pipeline has been in service for a period of time. The Code specifies the test pressure to be attained and the test duration in order to address certain threats. It also specifies allowable test mediums and under what conditions the various test mediums can be used.

The operator should consider the results of the risk assessment and the expected types of anomalies to determine when to conduct inspections utilizing pressure testing.

Time-Dependent Threats (B31.8S – 6.3.1)

Pressure testing is appropriate for use when addressing time-dependent threats. Time-dependent threats are external corrosion, internal corrosion, stress corrosion cracking, and other environmentally assisted corrosion mechanisms.

Manufacturing and Related Defect Threats (B31.8S – 6.3.2)

Pressure testing is appropriate for use when addressing the pipe seam aspect of the manufacturing threat. Pressure testing shall comply with the requirements of ASME B31.8. This will define whether air or water shall be used. Seam issues have been known to exist for pipe with a joint factor of less than 1.0 (e.g., lap-welded pipe, hammer-welded pipe, and butt-welded pipe) or if the pipeline is composed of low-frequency welded electric resistance welded (ERW) pipe or flash-welded pipe. References for determining if a specific pipe is susceptible to seam issues are Integrity Characteristics of Vintage Pipelines (The INGAA Foundation, Inc.) and History of Line Pipe Manufacturing in North America (ASME research report).

When raising the MAOP of a steel pipeline or when raising the operating pressure above the historical operating pressure (i.e., highest pressure recorded in 5 years prior to the effective date of this Code [ASME B31.8S]), pressure testing must be performed to address the seam issue.

Pressure testing shall be in accordance with ASME B31.8, to at least 1.25 times the MAOP. ASME B31.8 defines how to conduct tests for both post-construction and in-service pipelines.

All Other Threats (B31.8S – 6.3.3)

Pressure testing is typically not the appropriate integrity assessment method to use for all other threats listed in Subsection 2.6.5.2.1.

Examination and Evaluation (B31.8S – 6.3.4)

Any section of pipe that fails a pressure test shall be examined in order to evaluate that the failure was due to the threat that the test was intended to address. If the failure was due to another threat, the test failure information must be integrated with other information relative to the other threat and the segment reassessed for risk.

2.6.5.2.2.4 Direct Assessment (B31.8S – 6.4)

Direct assessment is an integrity assessment method utilizing a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination, and evaluation, in order to determine the integrity.

External Corrosion Direct Assessment (ECDA) for the External Corrosion Threat (B31.8S – 6.4.1)

External corrosion direct assessment can be used for determining integrity for the external corrosion threat on pipeline segments. The operator may use NACE SP0502 to conduct ECDA. The ECDA process integrates facilities data, and current and historical field inspections and tests, with the physical characteristics of a pipeline. Nonintrusive (typically aboveground or indirect) inspections are used to estimate the success of the corrosion protection. The ECDA process requires direct examinations and evaluations. Direct examinations and evaluations confirm the ability of the indirect inspections to locate active and past corrosion locations on the pipeline. Post-assessment is required to determine a corrosion rate to set the reinspection interval, reassess the performance metrics and their current applicability, and ensure the assumptions made in the previous steps remain correct.

The ECDA process therefore has the following four components:

(a) pre-assessment
(b) inspections
(c) examinations and evaluations
(d) post-assessment

The focus of the ECDA approach described in this Code [ASME B31.8S] is to identify locations where external corrosion defects may have formed. It is recognized that evidence of other threats such as mechanical damage and SCC may be detected during the ECDA process. While implementing ECDA and when the pipe is exposed, the operator is advised to conduct examinations for nonexternal corrosion threats.

The prescriptive ECDA process requires the use of at least two inspection methods, verification checks by examination and evaluations, and post-assessment validation.

For more information on the ECDA process as an integrity assessment method, see NACE SP0502, Pipeline External Direct Assessment Methodology.

Internal Corrosion Direct Assessment Process (ICDA) for the Internal Corrosion Threat (B31.8S – 6.4.2)

Internal corrosion direct assessment can be used for determining integrity for the internal corrosion threat on pipeline segments that normally carry dry gas but may suffer from short-term upsets of wet gas or free water (or other electrolytes). Examinations of low points or at inclines along a pipeline, which force an electrolyte such as water to first accumulate, provide information about the remaining length of pipe. If these low points have not corroded, then other locations further downstream are less likely to accumulate electrolytes and therefore can be considered free from corrosion. These downstream locations would not require examination.

Internal corrosion is most likely to occur where water first accumulates. Predicting the locations of water accumulation (if upsets occur) serves as a method for prioritizing local examinations. Predicting where water first accumulates requires knowledge about the multiphase flow behavior in the pipe, requiring certain data (see Subsection 2.6.5.4.1). ICDA applies between any feed points until a new input or output changes the potential for electrolyte entry or flow characteristics.

Examinations are performed at locations where electrolyte accumulation is predicted. For most pipelines it is expected that examination by radiography or ultrasonic NDE will be required to measure the remaining wall thickness at those locations. Once a site has been exposed, internal corrosion monitoring method(s) [e.g., coupon, probe, ultrasonic (UT) sensor] may allow an operator to extend the reinspection interval and benefit from real-time monitoring in the locations most susceptible to internal corrosion. There may also be some applications where the most effective approach is to conduct in-line inspection for a portion of pipe, and use the results to assess the downstream internal corrosion where in-line inspection cannot be conducted. If the locations most susceptible to corrosion are determined not to contain defects, the integrity of a large portion of the pipeline has been ensured. For more information on the ICDA process as an integrity assessment method, see Subsection 2.6.7.4.1, and the NACE 0206-2006 Standard Practice, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA).

Stress Corrosion Cracking Direct Assessment (SCCDA) for the Stress Corrosion Cracking Threat (B31.8S – 6.4.3)

Stress corrosion cracking direct assessment can be used to determine the likely presence or absence of SCC on pipeline segments by evaluating the SCC threat. Note that NACE RP0204 Stress Corrosion Cracking (SCC) Direct Assessment Methodology provides detailed guidance and procedures for conducting SCCDA. The SCCDA pre-assessment process integrates facilities data, current and historical field inspections, and tests with the physical characteristics of a pipeline. Nonintrusive (typically terrain, aboveground, and/or indirect) observations and inspections are used to estimate the absence of corrosion protection. The SCCDA process requires direct examinations and evaluations. Direct examinations and evaluations confirm the ability of the indirect inspections to locate evidence of SCC on the pipeline. Post assessment is required to set the re-inspection interval, re-assess the performance metrics and their current applicability, plus confirm the validity of the assumptions made in the previous steps remain correct.

The focus of the SCCDA approach described in this Code [ASME B31.8S] is to identify locations where SCC may exist. It is recognized that evidence of other threats such as external corrosion, internal corrosion, or mechanical damage may be detected during the SCCDA process. While implementing SCCDA, and when the pipe is exposed, the operator is advised to conduct examinations for non-SCC threats. For detailed information on the SCCDA process as an integrity assessment method, see especially NACE SP0204.

All Other Threats (B31.8S – 6.4.4)

Direct assessment is typically not the appropriate integrity assessment method to use for all other threats listed in Subsection 2.6.5.2.1.

2.6.5.2.2.5 Other Integrity Assessment Methodologies (B31.8S - 6.5)

Other proven integrity assessment methods may exist for use in managing the integrity of pipelines. For the purpose of this Code [ASME B31.8S], it is acceptable for an operator to use these inspections as an alternative to those listed above.

For prescriptive-based integrity management programs, the alternative integrity assessment shall be an industry-recognized methodology, and be approved and published by an industry consensus standards organization.

For performance-based integrity management programs, techniques other than those published by consensus standards organizations may be utilized; however, the operator shall follow the performance requirements of this Code [ASME B31.8S] and shall be diligent in confirming and documenting the validity of this approach to confirm that a higher level of integrity or integrity assurance was achieved.

2.6.5.2.3 Integrity Management Plan (B31.8S - 8)

2.6.5.2.3.1 General (B31.8S - 8.1)

The integrity management plan is developed after gathering the data (see Subsection 2.6.5.4.1) and completing the risk assessment (see Subsection 2.6.5.6.1) for each threat and for each pipeline segment or system. An appropriate integrity assessment method shall be identified for each pipeline system or segment. Integrity assessment of each system can be accomplished through a pressure test, an in-line inspection using a variety of tools, direct assessment, or use of other proven technologies (see Subsection 2.6.5.2.2). In some cases, a combination of these methods may be appropriate. The highest-risk segments shall be given priority for integrity assessment.

Following the integrity assessment, mitigation activities shall be undertaken. Mitigation consists of two parts. The first part is the repair of the pipeline. Repair activities shall be made in accordance with ASME B31.8 and/or other accepted industry repair techniques. Repair may include replacing defective piping with new pipe, installation of sleeves, coating repair, or other rehabilitation. These activities shall be identified, prioritized, and scheduled (see Subsection 2.6.11.6.1).

Once the repair activities are determined, the operator shall evaluate prevention techniques that prevent future deterioration of the pipeline. These techniques may include providing additional cathodic protection, injecting corrosion inhibitors and pipeline cleaning, or changing the operating conditions. Prevention plays a major role in reducing or eliminating the threats from third-party damage, external corrosion, internal corrosion, stress corrosion cracking, cold weather-related failures, earth movement failures, problems caused by heavy rains and floods, and failures caused by incorrect operations.
All threats cannot be dealt with through inspection and repair; therefore, prevention for these threats is a key element in the plan. These activities may include, for example, prevention of third-party damage and monitoring for outside force damage.

A performance-based integrity management plan, containing the same structure as the prescriptive-based plan, requires more detailed analyses based upon more complete data or information about the line. Using a risk assessment model, a pipeline operator can exercise a variety of options for integrity assessments and prevention activities, as well as their timing.

Prior integrity assessments and mitigation activities should only be included in the plan if they were as rigorous as those identified in this Code [ASME B31.8S].

2.6.5.2.3.2 Updating the Plan (B31.8S – 8.2)

Data collected during the inspection and mitigation activities shall be analyzed and integrated with previously collected data. This is in addition to other types of integrity management-related data that is constantly being gathered through normal operations and maintenance activities. The addition of this new data is a continuous process that, over time, will improve the accuracy of future risk assessments via its integration (see Subsection 2.6.5.4.1). This ongoing data integration and periodic risk assessment will result in continual revision to the integrity assessment and mitigation aspects of the plan. In addition, changes to the physical and operating aspects of the pipeline system or segment shall be properly managed (see Subsection 2.6.3.2.3).

This ongoing process will most likely result in a series of additional integrity assessments or review of previous integrity assessments. A series of additional mitigation activities or follow-up to previous mitigation activities may also be required. The plan shall be updated periodically as additional information is acquired and incorporated.

It is recognized that certain integrity assessment activities may be one-time events and focused on elimination of certain threats, such as manufacturing, construction, and equipment threats. For other threats, such as time-dependent threats, periodic inspection will be required. The plan shall remain flexible and incorporate any new information.

2.6.5.2.3.3 Plan Framework (B31.8S – 8.3)

The integrity management plan shall contain detailed information regarding each of the following elements for each threat analyzed and each pipeline segment or system.

Gathering, Reviewing, and Integrating Data (B31.8S – 8.3.1)

The first step in the integrity management process is to collect, integrate, organize, and review all pertinent and available data for each threat and pipeline segment. This process step is repeated after integrity assessment and mitigation activities have been implemented and as new operation and maintenance information about the pipeline system or segment is gathered. This information review shall be contained in the plan or in a database that is part of the plan. All data will be used to support future risk assessments and integrity evaluations. Data gathering is covered in Subsection 2.6.5.4.1.

Assess Risk (B31.8S – 8.3.2)

Risk assessment should be performed periodically to include new information, consider changes made to the pipeline system or segment, incorporate any external changes, and consider new scientific techniques that have been developed and commercialized since the last assessment. It is recommended that this be performed annually but shall be performed after substantial changes to the system are made and before the end of the current interval. The results of this assessment are to be reflected in the mitigation and integrity assessment activities. Changes to the acceptance criteria will also necessitate reassessment. The integrity management plan shall contain specifics about how risks are assessed and the frequency of reassessment. The specifics for assessing risk are covered in Subsection 2.6.5.6.1.

Integrity Assessment ((B31.8S – 8.3.3)

Based on the assessment of risk, the appropriate integrity assessments shall be implemented. Integrity assessments shall be con ducted using in-line inspection tools, pressure testing, and/or direct assessment. For certain threats, use of these tools may be inappropriate. Implementation of prevention activities or more frequent maintenance activities may provide a more effective solution. Integrity assessment method selection is based on the threats for which the inspection is being performed. More than one assessment method or more than one tool may be required to address all the threats. After each integrity assessment, this portion of the plan shall be modified to reflect all new information obtained and to provide for future integrity assessments at the required intervals. The plan shall identify required integrity assessment actions and at what established intervals the actions will take place. All integrity assessments shall be prioritized and scheduled.

Figure 2-23 provides the integrity assessment schedules for the external corrosion and internal corrosion time-dependent threats for prescriptive plans. The assessment schedule for the stress corrosion cracking threat is discussed in Subsection 2.6.5.4.2.3.4. The assessment schedules for all other threats are identified in appropriate chapters of Subsection 2.6.5.4.2 under the heading of Assessment Interval. A current prioritization listing and schedule shall be contained in this section of the integrity management plan. The specifics for selecting integrity assessment methods and performing the inspections are covered in Subsection 2.6.5.4.2.

A performance-based integrity management plan can provide alternative integrity assessment, repair, and prevention methods with different implementation times than those required under the prescriptive program. These decisions shall be fully documented.

Responses to Integrity Assessment, Mitigation (Repair and Prevention), and Intervals (B31.8S – 8.3.4)

The plan shall specify how and when the operator will respond to integrity assessments. The responses shall be immediate, scheduled, or monitored. The mitigation element of the plan consists of two parts. The first part is the repair of the pipeline. Based on the results of the integrity assessments and the threat being addressed, appropriate repair activities shall be determined and conducted. These repairs shall be performed in accordance with accepted standards and operating practices. The second part of mitigation is prevention. Prevention can stop or slow down future deterioration of the pipeline. Prevention is also an appropriate activity for time-independent threats. All mitigation activities shall be prioritized and scheduled. The prioritization and schedule shall be modified as new information is obtained and shall be a real-time aspect of the plan (see Subsection 2.6.11.6.1)

Figure 2-8, Figure 2-9, and Figure 2-10 provide an example of an integrity management plan in a spreadsheet format for a hypothetical pipeline segment (line 1, segment 3). This spreadsheet shows the segment data, the integrity assessment plan devised based on the risk assessment, and the mitigation plan that would be implemented, including the reassessment interval.

Figure 2-8: Example of Integrity Management Plan for Hypothetical Pipeline Segment (Segment Data: Line 1, Segment 3) (B31.8S - Table 8.3.4-1)

Segment Data	Type	Example
Pipe attributes	Pipe grade	API 5L-X42 (290 MPa)
	Size	NPS 24 (DN 600)
	Wall thickness	0.250 in. (6.35 mm)
	Manufacturer	A. O. Smith
	Manufacturer process	Low frequency
	Manufacturing date	1965
	Seam type	Electric resistance weld
Design/construction	Operating pressure (high/low)	630/550 psig (4 340/3 790 kPa)
	Operating stress	72% SMYS
	Coating type	Coal tar
	Coating condition	Fair
	Pipe install date	1966
	Joining method	Submerged arc weld
	Soil type	Clay
	Soil stability	Good
	Hydrostatic test	None
Operational	Compressor discharge temperature	120°F (49°C)
	Pipe wall temperature	65°F (18°C)
	Gas quality	Good
	Flow rate	50 MMSCFD (1.42 MSm^3/d)
	Repair methods	Replacement
	Leak/rupture history	None
	Pressure cycling	Low
	CP effectiveness	Fair
	SCC indications	Minor cracking

Figure 2-9: Example of Integrity Management Plan for Hypothetical Pipeline Segment (Integrity Assessment Plan: Line 1, Segment 3) (B31.8S - Table 8.3.4-2)

Threat	Criteria/Risk Assessment	Integrity Assessment	Mitigation	Interval, yr
External corrosion	Some external corrosion history, no in-line inspection	Conduct hydrostatic test, perform in-line inspection, or perform direct assessment	Replace/repair locations where CFP below 1.25 times the MAOP	10
Internal corrosion	No history of IC issues, no in-line inspection	Conduct hydrostatic test, perform in-line inspection, or perform direct assessment	Replace/repair locations where CFP below 1.25 times the MAOP	10
SCC	Have found SCC of near critical dimension	Conduct hydrostatic test	Replace pipe at test failure locations	3–5
Manufacturing	ERW pipe, joint factor <1.0, no hydrostatic test	Conduct hydrostatic test	Replace pipe at test failure locations	N/A
Construction/fabrication	No construction issues	None required	N/A	N/A
Equipment	No equipment issues	None required	N/A	N/A
Third-party damage	No third-party damage issues	None required	N/A	N/A
Incorrect operations	No operations issues	None required	N/A	N/A
Weather and outside force	No weather or outside force related issues	None required	N/A	N/A

Figure 2-10: Example of Integrity Management Plan for Hypothetical Pipeline Segment (Mitigation Plan: Line 1, Segment 3) (B31.8S - Table 8.3.4-3)

Example	Description
Repair	Any hydrostatic test failure will be repaired by replacement of the entire joint of pipe.
Prevention	Prevention activities will include further monitoring for SCC at susceptible locations, review of the cathodic protection design and levels, and monitoring for selective seam corrosion when the pipeline is exposed.
Interval for reinspection	The interval for reinspection will be 3 yr if there was a failure caused by SCC. The interval will be 5 yr if the test was successful.
Data integration	Test failures for reasons other than extemal or intemal corrosion, SCC, or seam defect must be considered when performing risk assessment for the associated threat.

GENERAL NOTE: For this pipeline segment, hydrostatic testing will be conducted. Selection of this method is appropriate due to its ability to address the internal and external corrosion threats as well as the manufacturing threat and the SCC threat. The test pressure will be at 1.39 times the MAOP.

2.6.5.3 CFR Language: 192.917(b)

(b) Data gathering and integration. To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, Section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and the non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

2.6.5.4 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 4. For user convenience, Section 4 and Appendix A of B31.8S has been included below.

2.6.5.4.1 Gathering, Reviewing, and Integrating Data (B31.8S - 4)

2.6.5.4.1.1 General (B31.8S - 4.1)

This section provides a systematic process for pipeline operators to collect and effectively utilize the data elements necessary for risk assessment. Comprehensive pipeline and facility knowledge is an essential component of a performance-based integrity management program. In addition, information on operational history, the environment around the pipeline, mitigation techniques employed, and process/procedure reviews is also necessary. Data are a key element in the decision-making process required for program implementation. When the operator lacks sufficient data or where data quality is below requirements, the operator shall follow the prescriptive-based processes as shown in Subsection 2.6.5.4.2.

Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are suitable for integrity/risk assessment. Integration of the data elements is essential in order to obtain complete and accurate information needed for an integrity management program.

2.6.5.4.1.2 Data Requirements (B31.8S - 4.2)

The operator shall have a comprehensive plan for collecting all data sets. The operator must first collect the data required to perform a risk assessment (see Subsection 2.6.5.6.1). Implementation of the integrity management program will drive the collection and prioritization of additional data elements required to more fully understand and prevent/mitigate pipeline threats.

Figure 2-11: Data Elements for Prescriptive Pipeline Integrity Program (B31.8S - Table 4.2.1-1)

Category	Data
Attribute data	Pipe wall thickness Diameter Seam type and joint factor Manufacturer Manufacturing date Material properties Equipment properties
Construction	Year of installation Bending method Joining method, process and inspection results Depth of cover Crossings/casings Pressure test Field coating methods Soil, backfill Inspection reports Cathodic protection installed Coating type
Operational	Gas quality Flow rate Normal maximum and minimum operating pressures Leak/failure history Coating condition CP (cathodic protection) system performance Pipe wall temperature Pipe inspection reports OD/ID corrosion monitoring Pressure fluctuations Regulator/relief performance Encroachments Repairs Vandalism External forces
Inspection	Pressure tests In-line inspections Geometry tool inspections Bell hole inspections CP inspections (CIS) Coating condition inspections (DCVG) Audits and reviews

Prescriptive Integrity Management Programs (B31.8S - 4.2.1)

Limited data sets shall be gathered to evaluate each threat for prescriptive integrity management program applications. These data lists are provided in Subsection 2.6.5.4.2 for each threat and summarized in Figure 2-11. All of the specified data elements shall be available for each threat in order to perform the risk assessment. If such data are not available, it shall be assumed that the particular threat applies to the pipeline segment being evaluated.

Performance-Based Integrity Management Programs (B31.8S - 4.2.2)

There is no standard list of required data elements that apply to all pipeline systems for performance-based integrity management programs. However, the operator shall collect, at a minimum, those data elements specified in the prescriptive-based program requirements. The quantity and specific data elements will vary between operators and within a given pipeline system. Increasingly complex risk assessment methods applied in performance-based integrity management programs require more data elements than those listed in Subsection 2.6.5.4.2.

Initially, the focus shall be on collecting the data necessary to evaluate areas of concern and other specific areas of high risk. The operator will collect the data required to perform system-wide integrity assessments, and any additional data required for general pipeline and facility risk assessments. This data is then integrated into the initial data. The volume and types of data will expand as the plan is implemented over years of operation.

2.6.5.4.1.3 Data Sources (B31.8S - 4.3)

The data needed for integrity management programs can be obtained from within the operating company and from external sources (e.g., industry-wide data). Typically, the documentation containing the required data elements is located in design and construction documentation, and current operational and maintenance records.

A survey of all potential locations that could house these records may be required to document what is available, its form (including the units or reference system), and to determine if significant data deficiencies exist. If deficiencies are found, action to obtain the data can be planned and initiated relative to its importance. This may require additional inspections and field data collection efforts.

Existing management information system (MIS) or geographic information system (GIS) databases and the results of any prior risk or threat assessments are also useful data sources. Significant insight can also be obtained from subject matter experts and those involved in the risk assessment and integrity management program processes. Root cause analyses of previous failures are a valuable data source. These may reflect additional needs in personnel training or qualifications.

Valuable data for integrity management program implementation can also be obtained from external sources. These may include jurisdictional agency reports and databases that include information such as soil data, demographics, and hydrology, as examples. Research organizations can provide background on many pipeline-related issues useful for application in an integrity management program. Industry consortia and other operators can also be useful information sources.

The data sources listed in Figure 2-12 are necessary for integrity management program initiation. As the integrity management program is developed and implemented, additional data will become available. This will include inspection, examination, and evaluation data obtained from the integrity management program and data developed for the performance metrics covered in Subsection 2.6.3.2.1.

Figure 2-12: Data Elements for Prescriptive Pipeline Integrity Program (B31.8S - Table 4.3-1)

Process and instrumentation drawings (P&ID)
Pipeline alignment drawings
Original construction inspector notes/records
Pipeline aerial photography
Facility drawings/maps
As-built drawings
Material certifications
Survey reports/drawings
Safety related condition reports
Operator standards/specifications
Industry standards/specifications
O&M procedures
Emergency response plans
Inspection records
Test reports/records
Incident reports
Compliance records
Design/engineering reports
Technical evaluations
Manufacturer equipment data

2.6.5.4.1.4 Data Collection, Review, and Analysis (B31.8S - 4.4)

A plan for collecting, reviewing, and analyzing the data shall be created and in place from the conception of the data collection effort. These processes are needed to verify the quality and consistency of the data. Records shall be maintained throughout the process that identify where and how unsubstantiated data is used in the risk assessment process, so its potential impact on the variability and accuracy of assessment results can be considered. This is often referred to as metadata or information about the data.

Data resolution and units shall also be determined. Consistency in units is essential for integration. Every effort should be made to utilize all of the actual data for the pipeline or facility. Generalized integrity assumptions used in place of specific data elements should be avoided.

Another data collection consideration is whether the age of the data invalidates its applicability to the threat. Data pertaining to time-dependent threats such as corrosion or stress corrosion cracking (SCC) may not be relevant if it was collected many years before the integrity management program was developed. Stable and time-independent threats do not have implied time dependence, so earlier data is applicable.

The unavailability of identified data elements is not a justification for exclusion of a threat from the integrity management program. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required.

2.6.5.4.1.5 Data Integration (B31.8S - 4.5)

Individual data elements shall be brought together and analyzed in their context to realize the full value of integrity management and risk assessment. A major strength of an effective integrity management program lies in its ability to merge and utilize multiple data elements obtained from several sources to provide an improved confidence that a specific threat may or may not apply to a pipeline segment. It can also lead to an improved analysis of overall risk.

For integrity management program applications, one of the first data integration steps includes development of a common reference system (and consistent measurement units) that will allow data elements from various sources to be combined and accurately associated with common pipeline locations. For instance, in-line inspection (ILI) data may reference the distance traveled along the inside of the pipeline (wheel count), which can be difficult to directly combine with over-the-line surveys such as close interval survey (CIS) that are referenced to engineering station locations.

Figure 2-11 describes data elements that can be evaluated in a structured manner to determine if a particular threat is applicable to the area of concern or the segment being considered. Initially, this can be accomplished without the benefit of inspection data and may only include the pipe attribute and construction data elements shown in Figure 2-11. As other information such as inspection data becomes available, an additional integration step can be performed to confirm the previous inference concerning the validity of the presumed threat. Such data integration is also very effective for assessing the need and type of mitigation measures to be used.

Data integration can also be accomplished manually or graphically. An example of manual integration is the superimposing of scaled potential impact area circles (see Subsection 2.6.1.2.1) on pipeline aerial photography to determine the extent of the potential impact area. Graphical integration can be accomplished by loading risk-related data elements into an MIS/GIS system and graphically overlaying them to establish the location of a specific threat. Depending on the data resolution used, this could be applied to local areas or larger segments. More-specific data integration software is also available that facilitates use in combined analyses. The benefits of data integration can be illustrated by the following hypothetical examples:

EXAMPLES:
(1) In reviewing ILI data, an operator suspects mechanical damage in the top quadrant of a pipeline in a cultivated field. It is also known that the farmer has been plowing in this area and that the depth of cover may be reduced. Each of these facts taken individually provides some indication of possible mechanical damage, but as a group the result is more definitive.
(2) An operator suspects that a possible corrosion problem exists on a large-diameter pipeline located in a populated area. However, a CIS indicates good cathodic protection coverage in the area. A direct current voltage gradient (DCVG) coating condition inspection is performed and reveals that the welds were tape-coated and are in poor condition. The CIS results did not indicate a potential integrity issue, but data integration prevented possibly incorrect conclusions.

2.6.5.4.2 Threat Process Charts and Prescriptive Integrity Management Plans (B31.8S Nonmandatory Appendix A)

2.6.5.4.2.1 External Corrosion Threat (B31.8S - A-1)

2.6.5.4.2.1.1. Scope (B31.8S – A-1.1)

Subsection 2.6.5.4.2.1 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, of external corrosion (see Figure 2-13). External corrosion is defined in this context to include galvanic corrosion and microbiologically influenced corrosion (MIC).

This section outlines the integrity management process for external corrosion in general and also covers some specific issues. Pipeline incident analysis has identified external corrosion among the causes of past incidents.

2.6.5.4.2.1.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-1.2)

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring more or additional activities.
(a) year of installation

(b) coating type
(c) coating condition
(d) years with adequate cathodic protection
(e) years with questionable cathodic protection
(f) years without cathodic protection
(g) soil characteristics
(h) pipe inspection reports (bell hole)
(i) MIC detected (yes, no, or unknown)
(j) leak history
(k) wall thickness
(l) diameter
(m) operating stress level (% SMYS)
(n) past hydrostatic test information

For this threat, the data is used primarily for prioritization of integrity assessment and/or mitigation activities. Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

2.6.5.4.2.1.3. Criteria and Risk Assessment (B31.8S – A-1.3)

For new pipelines or pipeline segments, the operator may wish to use the original material selection, design conditions, and construction inspections, as well as the current operating history, to establish the condition of the pipe. For this situation, the operator must determine that the construction inspections have an equal or greater rigor than that provided by the prescribed integrity assessment in this Code [ASME B31.8S].

In no case shall the interval between construction and the first required reassessment of integrity exceed 10 years for pipe operating above 60% SMYS, 13 years for pipe operating above 50% SMYS and at or below 60% SMYS, 15 years for pipe operating at or above 30% SMYS and at or below 50% SMYS, and 20 years for pipe operating below 30% SMYS.

For all pipeline segments older than those stated above, integrity assessment shall be conducted using a methodology, within the specified response interval, as provided Subsection 2.6.5.4.2.1.5.

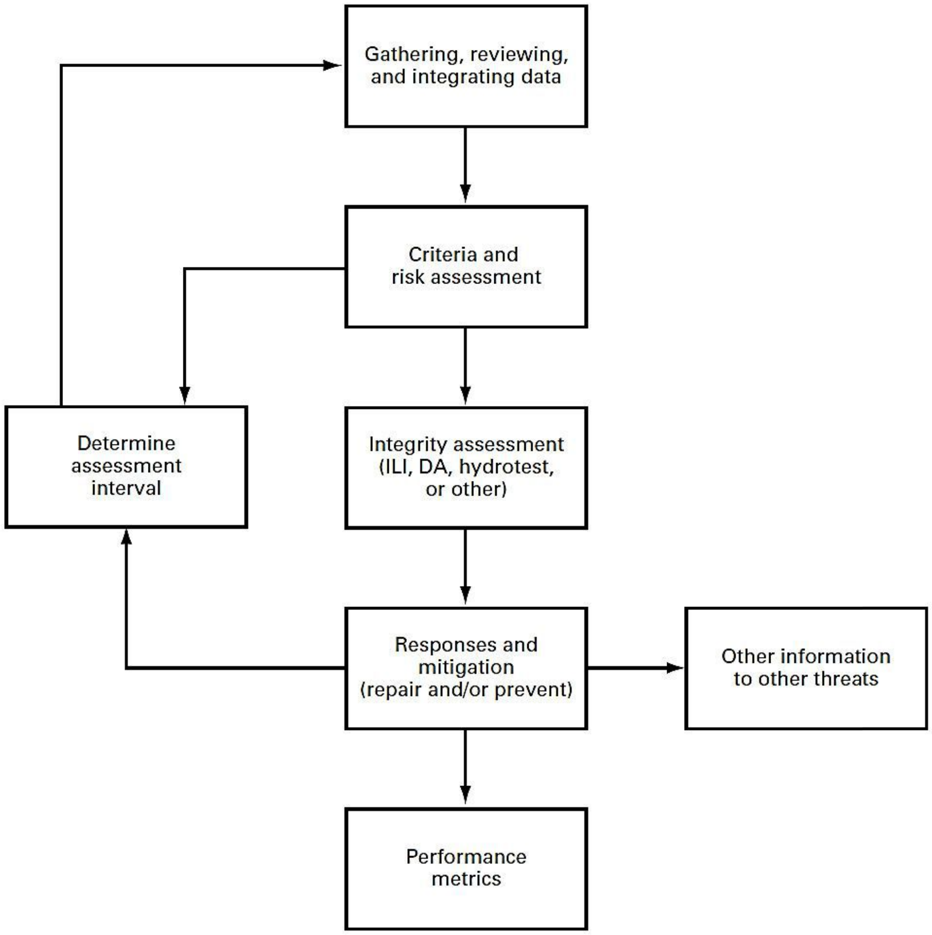
Previous integrity assessments can be considered as meeting these requirements, provided the inspections have equal or greater rigor than that provided by the prescribed inspections in this Code [ASME B31.8S]. The interval between the previous integrity assessment and the next integrity assessment cannot exceed the interval stated in this Code [ASME B31.8S].

2.6.5.4.2.1.4. Integrity Assessment (B31.8S – A-1.4)

The operator has a choice of three integrity assessment methods: in-line inspection with a tool cap able of detecting wall loss, such as an MFL tool; performing a pressure test; or conducting direct assessment.

(a) *In-Line Inspection* - The operator shall consult Subsection 2.6.5.2.2, which defines the capability of various ILI devices and provides criteria for running of the tool. The operator selects the appropriate tools and he/she or his/her representative performs the inspection.

Figure 2-13: Integrity Management Plan, External Corrosion Threat (Simplified Process: Prescriptive) (B31.8S - Fig. A-1.1-1)



(b) *Pressure Test* - The operator shall consult Subsection 2.6.5.2.2, which defines how to conduct tests for both post-construction and in-service pipelines. The operator selects the appropriate test and he/she or his/her representative performs the test.
(c) *Direct Assessment* - The operator shall consult Subsection 2.6.5.2.2, which defines the process, tools, and inspections. The operator selects the appropriate tools and he/she or his/her representative performs the inspections.

2.6.5.4.2.1.5. Responses and Mitigation (B31.8S – A-1.5)

Responses to integrity assessments are detailed below.
(a) *In-Line Inspection* - The response is dependent on the severity of corrosion as determined by calculating critical failure pressure of indications (see ASME B31G or equivalent) and a reasonably anticipated or scientifically proven rate of corrosion. Refer to Subsection 2.6.11.6.1 for responses to integrity assessment.
(b) *Direct Assessment* - The response is dependent on the number of indications examined, evaluated, and repaired. Refer to Subsection 2.6.11.6.1 for responses to integrity assessment.
(c) *Pressure Testing* - The interval is dependent on the test pressure. If the test pressure was at least 1.39 times MAOP, the interval shall be 10 years. If the test pressure was at least 1.25 times MAOP, the interval shall be 5 years (see Subsection 2.6.11.6.1).

If the actual operating pressure is less than MAOP, the factors shown above can be applied to the actual operating pressure in lieu of MAOP for ensuring integrity at the reduced pressure only.

The operator shall select the appropriate repair methods as outlined in Subsection 2.6.11.6.1.

The operator shall select the appropriate prevention practices as outlined in Subsection 2.6.11.6.1.

2.6.5.4.2.1.6. Other Data (B31.8S – A-1.6)

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when conducting an ILI with an MFL tool, dents may be detected on the top half of the pipe. This may have been caused by third-party damage. It is appropriate then to use this information when conducting risk assessment for the third-party damage threat.

2.6.5.4.2.1.7. Assessment Interval (B31.8S – A-1.7)

The operator is required to assess integrity periodically. The interval for assessments is dependent on the responses taken as outlined in Subsection 2.6.5.4.2.1.5.

These intervals are maximum intervals. The operator must incorporate new data into the assessment as data becomes available and that may require more frequent integrity assessments. For example, a leak on the segment that may be caused by external corrosion should necessitate immediate reassessment.

Changes to the segment may also require reassessment. Change management is addressed in this Code [ASME B31.8S] in Subsection 2.6.3.2.3.

2.6.5.4.2.1.8. Performance Measures (B31.8S – A-1.8)

The following performance measures shall be documented for the external corrosion threat, in order to establish the effectiveness of the program and for confirmation of the integrity assessment interval:
(a) number of hydrostatic test failures caused by external corrosion
(b) number of repair actions taken due to in-line inspection results, immediate and scheduled
(c) number of repair actions taken due to direct assessment results, immediate and scheduled
(d) number of external corrosion leaks (for low-stress pipelines it may be beneficial to compile leaks by leak classification)

2.6.5.4.2.2 Internal Corrosion Threat (B31.8S – A-2)

2.6.5.4.2.2.1. Scope (B31.8S – A-2.1)

Subsection 2.6.5.4.2.2 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, of internal corrosion. Internal corrosion is defined in this context to include chemical corrosion and internal microbiologically influenced corrosion (MIC; see Figure 2-14).

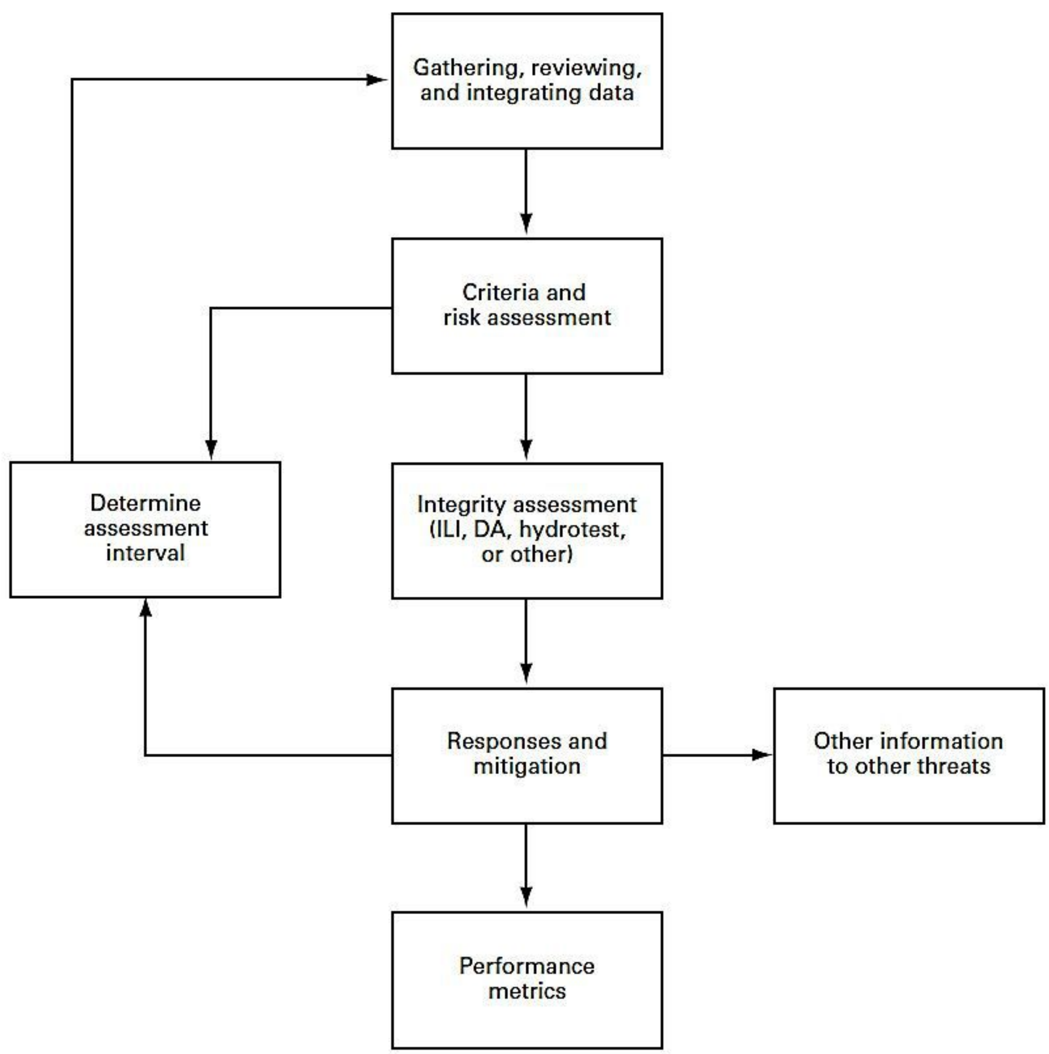
Subsection 2.6.5.4.2.2 provides a general overview of the integrity management process for internal corrosion in general and also covers some specific issues. Pipeline incident analysis has identified internal corrosion among the causes of past incidents.

2.6.5.4.2.2.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-2.2)

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring more or additional activities.
(a) year of installation
(b) pipe inspection reports (bell hole)

(c) leak history
(d) wall thickness
(e) diameter
(f) past hydrostatic test information
(g) gas, liquid, or solid analysis (particularly hydrogen sulfide, carbon dioxide, oxygen, free water, and chlorides)
(h) bacteria culture test results
(i) corrosion detection devices (coupons, probes, etc.)
(j) operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)
(k) operating stress level (% SMYS)

Figure 2-14: Integrity Management Plan, Internal Corrosion Threat (Simplified Process: Prescriptive) (B31.8S - Fig. A-2.1-1)



For this threat, the data is used primarily for prioritization of integrity assessment and/or mitigation activities. Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

2.6.5.4.2.2.3. Criteria and Risk Assessment (B31.8S – A-2.3)

For new pipelines or pipeline segments, the operator may wish to use the original material selection, design conditions, and construction inspections, as well as the current operating history, to establish the condition of the pipe. For this situation, the operator must determine that the construction inspections have an equal or greater rigor than that provided by the prescribed integrity assessments in this Code [ASME B31.8S]. In addition, the operator shall determine that a corrosive environment does not exist.

In no case may the interval between construction and the first required reassessment of integrity exceed 10 years for pipe operating above 60% SMYS, 13 years for pipe operating above 50% SMYS and at or below 60% SMYS, and 15 years for pipe operating at or below 50% SMYS.

For all pipeline segments older than those stated above, integrity assessment shall be conducted using a methodology within the specified response interval, as provided in Subsection 2.6.5.4.2.2.5.

Previous integrity assessments can be considered as meeting these requirements provided the inspections have equal or greater rigor than that provided by the prescribed inspections in this Code [ASME B31.8S]. The interval between the previous integrity assessment and the next integrity assessment cannot exceed the interval stated in this Code [ASME B31.8S].

2.6.5.4.2.2.4. Integrity Assessment (B31.8S – A-2.4)

The operator has a choice of three integrity assessment methods: in-line inspection with a tool capable of detecting wall loss, such as an MFL tool; performing a pressure test; or conducting direct assessment.

(a) *In-Line Inspection* - For in-line inspection, the operator must consult Subsection 2.6.5.2.2, which defines the capability of various ILI devices and provides criteria for running of the tool. The operator selects the appropriate tools and he/she or his/her representative performs the inspection.

(b) *Pressure Test* - The operator shall consult Subsection 2.6.5.2.2, which defines how to conduct tests for both post-construction and in-service pipelines. The operator selects the appropriate test and he/she or his/her representative performs the test.

(c) *Direct Assessment* - The operator shall consult Subsection 2.6.5.2.2, which defines the process, tools, and inspections. The operator selects the appropriate tools and he/she or his/her representative performs the inspections.

2.6.5.4.2.2.5. Responses and Mitigation (B31.8S – A-2.5)

Responses to integrity assessments are detailed below.

(a) *In-Line Inspection* - The response is dependent on the severity of corrosion, as determined by calculating critical failure pressure of indications (see ASME B31G or equivalent) and a reasonably anticipated or scientifically proven rate of corrosion. Refer to Subsection 2.6.11.6.1 for responses to integrity assessments.

(b) *Direct Assessment* - The response is dependent on the number of indications examined, evaluated, and repaired. Refer to Subsection 2.6.11.6.1 for responses to integrity assessment. An acceptable method to address dry gas internal corrosion is NACE SP0206.

(c) *Pressure Testing* - The interval is dependent on the hydrostatic test pressure. If the test pressure was at least 1.39 times MAOP, the interval is 10 years. If the test pressure was at least 1.25 times MAOP, the interval is 5 years (see Subsection 2.6.11.6.1).

If the actual operating pressure is less than MAOP, the factors shown above can be applied to the actual operating pressure in lieu of MAOP for the purposes of insuring integrity at the reduced pressure only.

The operator shall select the appropriate repair methods as outlined in Subsection 2.6.11.6.1.

The operator shall select the appropriate prevention practices as outlined in Subsection 2.6.11.6.1. Data confirming that a corrosive environment exists should prompt the design of a mitigation plan of action and immediate implementation should occur. Data suggesting that a corrosive environment may exist should prompt an immediate reevaluation. If the data shows that no corrosive condition or environment exists, then the operator should identify the conditions that would prompt reevaluation.

2.6.5.4.2.2.6. Other Data (B31.8S – A-2.6)

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when conducting an ILI with an MFL tool, dents may be called out on the top half of the pipe. This may have been caused by third-party damage. It is appropriate then to use this data when conducting integrity assessment for the third-party damage threat.

2.6.5.4.2.2.7. Assessment Interval (B31.8S – A-2.7)

The operator is required to assess integrity periodically. The interval for assessment is dependent on the responses taken, as outlined in Subsection 2.6.5.4.2.2.5.

These intervals are maximum intervals. The operator shall incorporate new data into the assessment as data becomes available, and that may require more frequent integrity assessments. For example, a leak on the segment that may be caused by internal corrosion would necessitate immediate reassessment.

Changes to the segment may also drive reassessment. This change management is addressed in Subsection 2.6.3.2.3.

2.6.5.4.2.2.8. Performance Metrics (B31.8S – A-2.8)

The following performance metrics shall be documented for the internal corrosion threat, in order to establish the effectiveness of the program and for confirmation of the integrity assessment interval:
(a) number of hydrostatic test failures caused by internal corrosion
(b) number of repair actions taken due to in-line inspection results, immediate and scheduled
(c) number of repair actions taken due to direct assessment results, immediate and scheduled
(d) number of internal corrosion leaks (for low stress pipelines, it may be beneficial to compile leaks by leak grade)

2.6.5.4.2.3 Stress Corrosion Cracking Threat (B31.8S – A-3)

2.6.5.4.2.3.1. Scope (B31.8S – A-3.1)

Subsection 2.6.5.4.2.3 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for stress corrosion cracking (SCC) of gas line pipe. Methods of assessment include hydrostatic testing, in-line inspection, and SCC direct assessment (SCCDA). Engineering Assessment can be used to evaluate the extent and severity of the threat, to identify and select examination and testing strategies, and/or to develop technically defensible plans that demonstrate satisfactory pipeline safety performance. Included in this section is a description of a process utilizing Engineering Assessment that can be used to select an integrity assessment method or to customize one of the methods for a specific pipeline. This process is applicable to both near neutral pH and high pH SCC. Integrity assessment and mitigation plans for both phenomena are discussed in published research literature. This section does not address all possible means of inspecting for mitigation of SCC. As new tools and technologies are developed, they can be evaluated and be available for use by the operator. Additional guidance for management of SCC can be found in ASME STP-PT-011, Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas.

2.6.5.4.2.3.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-3.2)

The following minimal data sets should be collected for each segment and reviewed before a threat assessment can be conducted. Additionally, these data are collected for special considerations, such as identifying severe situations requiring more or additional activities.
(a) age of pipe
NOTE: Age of pipe coating may be used if the pipeline segment has been assessed for SCC.
(b) operating stress level (% SMYS)
(c) operating temperature
(d) distance of the segment downstream from a compressor station
(e) coating type
(f) past hydrotest information
Where the operator is missing data, conservative assumptions shall be used when performing the risk analysis or, alternatively, the segment shall be prioritized higher.

2.6.5.4.2.3.3. Criteria and Threat Assessment (B31.8S – A-3.3)

Possible Threat of Near-Neutral pH SCC (B31.8S – A.3.3.1)

Each segment should be assessed for the possible threat of near-neutral pH SCC if all of the following criteria are present:
(a) operating stress level >60% SMYS.
(b) age of pipe >10 years.
NOTE: Age of pipe coating may be used if the pipeline segment has been assessed for SCC.
(c) all corrosion coating systems other than plant-applied or field-applied fusion bonded epoxy (FBE) or liquid epoxy (when abrasive surface preparation was used during field coating application). Field joint coating systems should also be considered for their susceptibility using the criteria in this section.

Possible Threat of High pH SCC (B31.8S – A-3.3.2)

Each segment should be assessed for the possible threat of high pH SCC if the three criteria above are present and the following two criteria are also present:
(a) operating temperature >100°F (38°C)
(b) distance from compressor station discharge ≤20 mi (32 km)

Additional Considerations (B31.8S – A-3.3.3)

In addition, each segment in which one or more service incidents or one or more hydrostatic test breaks or leaks has been caused by one of the two types of SCC shall be evaluated, unless the conditions that led to the SCC have been corrected. For this threat, the threat assessment consists of comparing the data elements to the criteria. If the conditions of the criteria are met or if the segment has a previous SCC history (i.e., bell hole inspection indicating the presence of SCC, hydrotest failures caused by SCC, in-service failures caused by SCC, or leaks caused by SCC), the pipe is considered to be at risk for the occurrence of SCC. Otherwise, if one of the conditions of the criteria is not met and if the segment does not have a history of SCC, no action is required.

2.6.5.4.2.3.4. Integrity Assessment (B31.8S – A-3.4)

If conditions for SCC are present (i.e., meet the criteria in Subsection 2.6.5.4.2.3.3), a written inspection, examination, and evaluation plan shall be prepared. The plan should give consideration to integrity assessment for other threats and prioritization among other segments that are at risk for SCC.

Figure 2-15: SCC Crack Severity Criteria (B31.8S - Table A-3.4-1)

Category	Crack Severity	Remaining Life
0	Crack of any length having depth <10% WT, or crack with 2 in. (51 mm) maximum length and depth less than 30% WT	Exceeds 15 yr
1	Predicted failure pressure >110% SMYS	Exceeds 10 yr
2	110% SMYS ≥ predicted failure pressure >125% MAOP	Exceeds 5 yr
3	125% MAOP ≥ predicted failure pressure >110% MAOP	Exceeds 2 yr
4	Predicted failure pressure ≤110% MAOP	Less than 2 yr

If the pipeline experiences an in-service leak or rupture that is attributed to SCC, the particular segment shall be subjected to a hydrostatic test (as described below) within 12 months. A documented hydrostatic retest program shall be developed for this segment. Note that hydrostatic pressure testing is required. Use of test media other than water is not permitted.

Acceptable inspection and mitigation methods for addressing pipe segments at risk for SCC are covered in four paragraphs below.

The severity of SCC indications is characterized by Figure 2-15. Several alternative fracture mechanics approaches exist for operators to use for crack severity assessment. The values in Figure 2-15 have been developed for typical pipeline attributes and representative SCC growth rates, using widely accepted fracture mechanics analysis methods.

Bell Hole Examination and Evaluation Method (B31.8S – A-3.4.1)

Magnetic particle inspection methods (MPI), or other equivalent nondestructive evaluation methods, shall be used when disbonded coating or bare pipe is encountered during integrity-related excavation of pipeline segments susceptible to SCC. Excavations where the pipe is not completely exposed (e.g., encroachments, exothermically welded attachments and foreign line crossings where the operator may need only to remove soil from the top portion of the pipe) are not subject to the MPI requirement as described unless there is a prior history of SCC in the segment. Coating condition should be assessed and documented. All SCC inspection activities shall be conducted using documented procedures. Any indications of SCC shall be addressed using guidance from Figure 2-15 and Figure 2-16.

The response requirements applicable to the SCC crack severity categories are provided in Figure 2-16. The response requirements in Figure 2-16 incorporate conservative assumptions regarding remaining flaw sizes. Alternatively, an engineering critical assessment may be conducted to evaluate the threat.

Hydrostatic Testing for SCC (B31.8S – A-3.4.2)

Hydrostatic testing conditions for SCC mitigation have been developed through industry research to optimize the removal of critical-sized flaws while minimizing growth of subcritical-sized flaws. Hydrostatic testing utilizing the criteria in this section is considered an integrity assessment for SCC. Recommended hydrostatic test criteria are as follows:

(a) high-point test pressure equivalent to a minimum of 100% SMYS.

(b) target test pressure shall be maintained for a minimum period of 10 min.

(c) upon returning the pipeline to gas service, an instrumented leak survey (e.g., a flame ionization survey) shall be performed. (Alternatives may be considered for hydrostatic test failure events due to causes other than SCC.)

(d) Results

(1) No SCC Hydrostatic Test Leak or Rupture. If no leaks or ruptures due to SCC occurred, the operator shall use one of the following two options to address long-term mitigation of SCC:

(i) implement a written hydrostatic retest program with a technically justifiable interval or

(ii) perform Engineering Assessment to evaluate the threat and identify further mitigation methods [see para. A-3.4.2(d)(3)]

(2) SCC Hydrostatic Test Leak or Rupture. If a leak or rupture due to SCC occurred, the operator shall establish a written hydrostatic retest program and procedure with justification for the retest interval. An example of an SCC hydrostatic retest approach is found in IPC2006-10163, Method for Establishing Hydrostatic Re-Test Intervals for Pipelines with Stress Corrosion Cracking.

In-Line Inspection for SCC (B31.8S – A-3.4.3)

Industry experience has indicated some successful use of in-line inspection (ILI) for SCC in gas pipelines. Refer to Subsection 2.6.11.6.1.2 for appropriate response to indications of SCC identified by in-line inspection. Figure 2-15 can be used to establish a reassessment interval for ILI, provided that the entire segment has been inspected.

Stress Corrosion Cracking Direct Assessment (SCCDA) (B31.8S – A-3.4.4)

SCCDA is a formal process to assess a pipe segment for the presence and severity of SCC, primarily by examining with MPI or equivalent technology selected joints of pipe within that segment after systematically gathering and analyzing data for pipe having similar operational characteristics and residing in a similar physical environment. The SCCDA process includes guidance for operators to select appropriate sites to conduct excavations for the purposes of conducting an SCC integrity assessment. Detailed guidance for this process is provided in NACE SP0204, Stress Corrosion Cracking Direct Assessment (SCCDA) Methodology.

Figure 2-16: Actions Following Discovery of SCC during Excavation (Table B31.8S - A-3.4.1-1)

Crack Severity	Response Requirement
No SCC or Category 0	Schedule SCCDA as appropriate. A single excavation for SCC is adequate.
Category 1	Conduct a minimum of two additional excavations. If the largest flaw is Category 1, conduct next assessment in 3 yr. If the largest flaw is Category 2, 3, or 4, follow the response requirement applicable to that category.
Category 2	Consider temporary pressure reduction until hydrotest, ILI, or MPI completed. Assess the segment using hydrotest, ILI, or 100% MPI examination, or equivalent, within 2 yr. The type and timing of further assessment(s) depend on the results of hydrotest, ILI, or MPI.
Category 3	Immediate pressure reduction and assessment of the segment using one of the following: *(a)* hydrostatic test *(b)* ILI *(c)* 100% MPI, or equivalent, examination
Category 4	Immediate pressure reduction and assessment of the segment using one of the following: *(a)* hydrostatic test *(b)* ILI *(c)* 100% MPI, or equivalent, examination

2.6.5.4.2.3.5. Other Data (B31.8S – A-3.5)

During the integrity assessment and mitigation activities, the operator may discover other data that may be pertinent to other threats. These data should be used where appropriate for performing risk assessments for other threats.

2.6.5.4.2.3.6. Performance Measures (B31.8S – A-3.6)

The following performance measures shall be documented for the SCC threat, in order to establish the effectiveness of the program and for confirmation of the inspection interval:
(a) number of in-service leaks/failures due to SCC
(b) number of repairs or replacements due to SCC
(c) number of hydrostatic test failures due to SCC

2.6.5.4.2.4 Manufacturing Threat (Pipe Seam and Pipe) (B31.8S – A-4)

2.6.5.4.2.4.1. Scope (B31.8S – A-4.1)

Subsection 2.6.5.4.2.4 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for manufacturing concerns. Manufacturing is defined in this context as pipe seam and pipe (see Figure 2-17).

This section outlines the integrity management process for manufacturing concerns in general and also covers some specific issues. Pipeline incident analysis has identified manufacturing among the causes of past incidents.

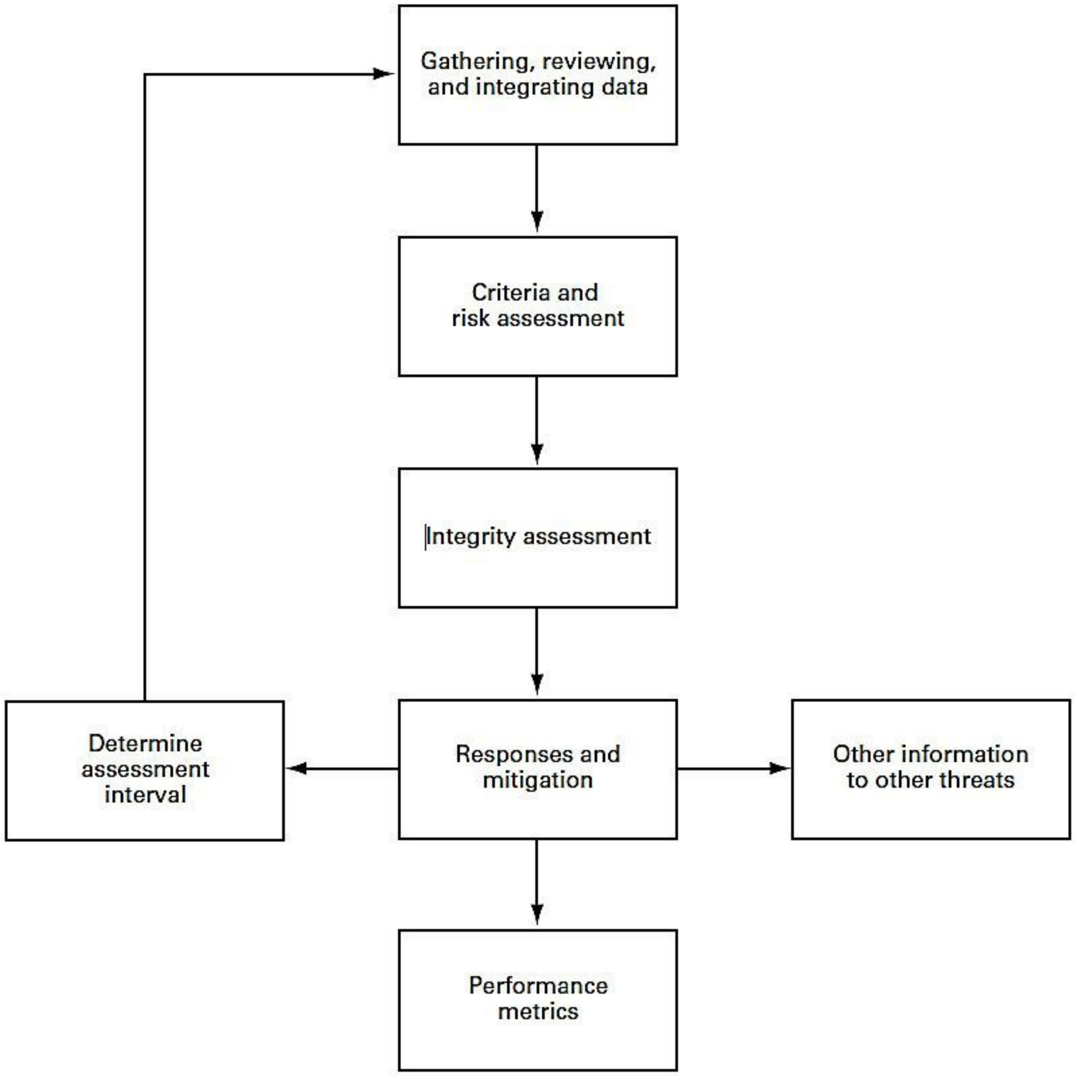
2.6.5.4.2.4.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-4.2)

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected for performing risk assessment and for special considerations such as identifying severe situations requiring more or additional activities.
(a) pipe material
(b) year of installation
(c) manufacturing process (age of manufacture as alternative; see note below)
(d) seam type
(e) joint factor
(f) operating pressure history

Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

NOTE: When pipe data is unknown, the operator may refer to History of Line Pipe Manufacturing in North America by J. F. Kiefner and E. B. Clark, 1996, ASME.

Figure 2-17: Integrity Management Plan, Manufacturing Threat (Pipe Seam and Pipe; Simplified Process: Prescriptive) (B31.8S - Fig. A-4.1-1)



2.6.5.4.2.4.3. Criteria and Risk Assessment (B31.8S – A-4.3)

For cast iron pipe, steel pipe manufactured prior to 1952, mechanically coupled pipelines, or pipelines joined by means of acetylene girth welds, where low temperatures are experienced or where the pipe is exposed to movement such as land movement or removal of supporting backfill, examination of the terrain is required. If land movement is observed or can reasonably be anticipated, a pipeline movement monitoring program should be established and appropriate intervention activities undertaken. If the pipe has a joint factor of less than 1.0 (such as lap-welded pipe, hammer-welded pipe, and buttwelded pipe) or if the pipeline is composed of low-frequency-welded ERW pipe or flash-welded pipe, a manufacturing threat is considered to exist.

Fatigue along longitudinal pipe seams due to operating pressure cycles has not been a significant issue for natural gas pipelines. However, if the pipeline segment operates with significant pressure fluctuations, seam fatigue shall be considered by the operator as an additional integrity threat. GRI Report GRI-04/0178, Effects of Pressure Cycles on Gas Pipelines, may be a useful reference regarding fatigue due to pressure cycling.

2.6.5.4.2.4.4. Integrity Assessment (B31.8S – A-4.4)

For cast iron pipe, the assessment should include evaluation as to whether or not the pipe is subject to land movement or subject to removal of support. For steel pipe seam concerns, when raising the MAOP of a pipeline or when raising the operating pressure above the historical operating pressure (highest pressure recorded in the past 5 years), pressure testing must be performed to address the seam issue. Pressure testing shall be in accordance with ASME B31.8; to at least 1.25 times the MAOP. ASME B31.8 defines how to conduct tests for both post-construction and in-service pipelines.

2.6.5.4.2.4.5. Responses and Mitigation (B31.8S – A-4.5)

For cast iron pipe, mitigation options include replacement of pipe or stabilization of pipe.

For steel pipe, any section that fails the pressure test must be replaced.

The operator shall select the appropriate prevention practices. For this threat, the operator should develop pipe specifications to be used when ordering pipe that meets or exceeds the requirements of ASME B31.8.

2.6.5.4.2.4.6. Other Data (B31.8S – A-4.6)

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, certain seam types may be more susceptible to accelerated corrosion. It is appropriate to use this information when conducting risk assessments for external or internal corrosion.

2.6.5.4.2.4.7. Assessment Interval (B31.8S – A-4.7)

Periodic integrity assessment is not required. Changes to the segment may drive reassessment, such as uprating the pipeline's operating pressure, or changes in operating conditions, such as significant pressure cycling. Change management is addressed in Subsection 2.6.3.2.3.

2.6.5.4.2.4.8. Performance Measures (B31.8S – A-4.8)

The following performance measures shall be documented for the manufacturing threat, in order to establish the effectiveness of the program and for confirmation of the inspection interval:
(a) number of hydrostatic test failures caused by manufacturing defects
(b) number of leaks due to manufacturing defects

2.6.5.4.2.5 Construction Threat (Pipe Girth Weld, Fabrication Weld, Wrinkle Bend or Buckle, Stripped Threads/Broken Pipe/ Coupling) (B31.8S – A-5)

2.6.5.4.2.5.1. Scope (B31.8S – A-5.1)

Subsection 2.6.5.4.2.5 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for construction concerns. Construction is defined in this context as pipe girth weld, fabrication weld, wrinkle bend or buckle, stripped threads, broken pipe, or coupling (see Figure 2-18).

This section outlines the integrity management process for construction concerns in general, and also covers some specific issues. Pipeline incident analysis has identified construction among the causes of past incidents.

2.6.5.4.2.5.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-5.2)

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected to support performing risk assessment and for special considerations, such as identifying severe situations requiring more or additional activities.

(a) pipe material
(b) wrinkle bend identification
(c) coupling identification
(d) post-construction coupling reinforcement
(e) welding procedures
(f) post-construction girth weld reinforcement
(g) NDT information on welds
(h) hydrostatic test information
(i) pipe inspection reports (bell hole)
(j) potential for outside forces (see Section 2.6.5.4.2.9 (ASME B31.8S - A-9))
(k) soil properties and depth of cover for wrinkle bends
(l) maximum temperature ranges for wrinkle bends
(m) bend radii and degrees of angle change for wrinkle bends
(n) operating pressure history and expected operation, including significant pressure cycling and fatigue mechanism

Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

2.6.5.4.2.5.3. Criteria and Risk Assessment (B31.8S – A-5.3)

For girth welds, a review of the welding procedures and NDT information is required to ascertain that the welds are adequate.

For fabrication welds, a review of the welding procedures and NDT information, as well as a review of forces due to ground settlement or other outside loads, is required to ascertain that the welds are adequate.

For wrinkle bends and buckles as well as couplings, reports of visual inspection should be reviewed to ascertain their continued integrity. Potential movement of the pipeline may cause additional lateral and/or axial stresses. Information relative to pipe movement should be reviewed, such as temperature range, bend radius, degree of bend, depth of cover, and soil properties. These are important factors in determining whether or not bends are being subjected to injurious stresses or strains.

The existence of these construction-related threats alone does not pose an integrity issue. The presence of these threats in conjunction with the potential for outside forces significantly increases the likelihood of an event. The data must be integrated and evaluated to determine where these construction characteristics coexist with external or outside force potential.

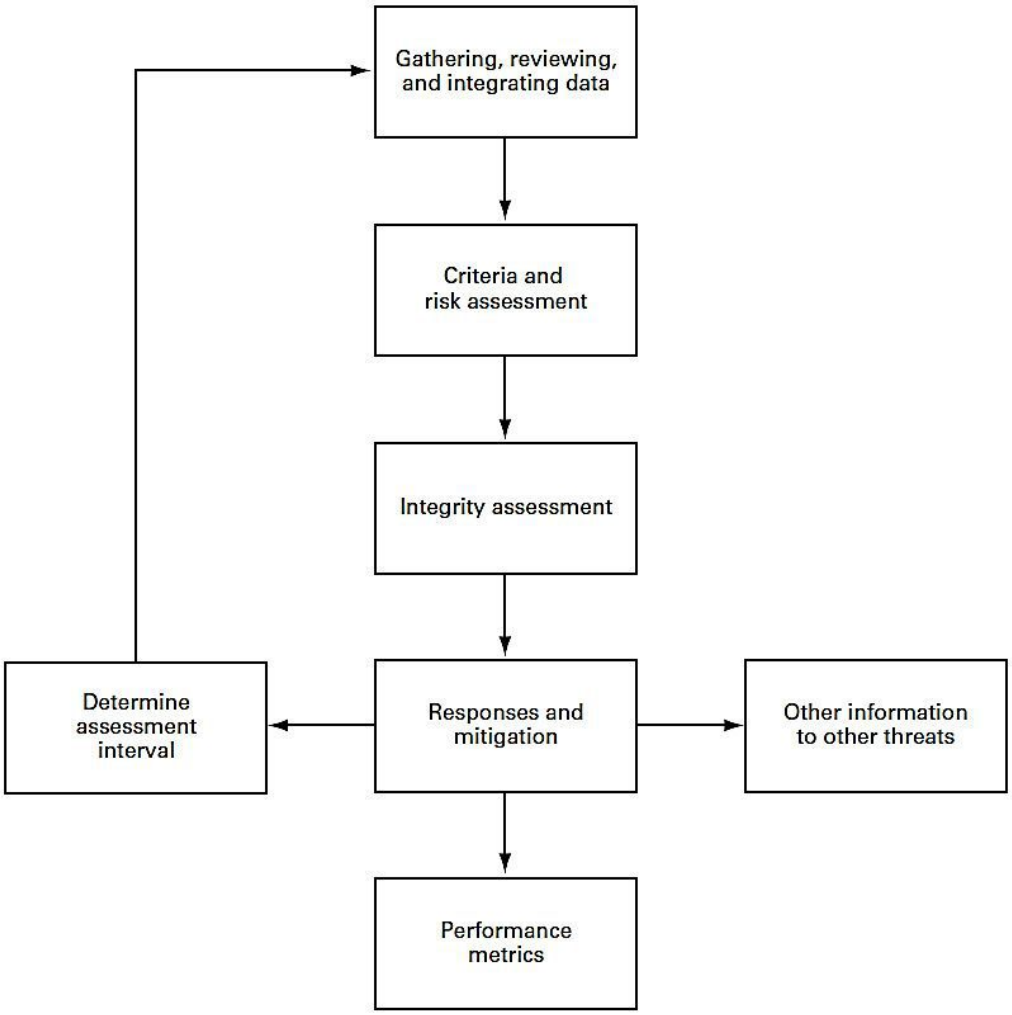
2.6.5.4.2.5.4. Integrity Assessment (B31.8S – A-5.4)

For construction threats, the inspection should be by data integration, examination, and evaluation for threats that are coincident with the potential for ground movement or outside forces that will impact the pipe.

2.6.5.4.2.5.5. Responses and Mitigation (B31.8S – A-5.5)

The operator shall select the appropriate prevention practices. For this threat, the operator should develop excavation protocols to ensure the pipe is not moved and additional stresses introduced. In addition, the operator should conduct examinations and evaluations every time the pipe is exposed. Potential threats should be mitigated by proactive procedures that require inspection, repair, replacement, or reinforcement when the need to inspect the pipeline for other maintenance reasons occurs.

Figure 2-18: Integrity Management Plan, Construction Threat (Pipe Girth Weld, Fabrication Weld, Wrinkle Bend or Buckle, Stripped Threads/Broken Pipe/Coupling; Simplified Process: Prescriptive) (B31.8s - Fig. A-5.1-1)



2.6.5.4.2.5.6. Other Data (B31.8S – A-5.6)

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, certain seam types may be more susceptible to accelerated corrosion. It is appropriate to use this information when conducting risk assessments for external or internal corrosion.

2.6.5.4.2.5.7. Assessment Interval (B31.8S – A-5.7)

Periodic assessment is not required. Changes to the segment or changes in land use may drive reassessment. Change management is addressed in Subsection 2.6.3.2.3.

2.6.5.4.2.5.8. Performance Measures (B31.8S – A-5.8)

The following performance measures shall be documented for the construction threat, in order to establish the effectiveness of the program:
(a) number of leaks or failures due to construction defects
(b) number of girth welds/couplings reinforced/removed
(c) number of wrinkle bends removed
(d) number of wrinkle bend inspections
(e) number of fabrication welds repaired/removed

2.6.5.4.2.6 Equipment Threat (Gaskets and O-Rings, Control/Relief, Seal/Pump Packing) (B31.8S – A-6)

2.6.5.4.2.6.1. Scope (B31.8S – A-6.1)

Subsection 2.6.5.4.2.6 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for pipeline equipment failure. Equipment is defined in this context as pipeline facilities other than pipe and pipe components. Meter/regulator and compressor stations are typical equipment locations (see Figure 2-19).

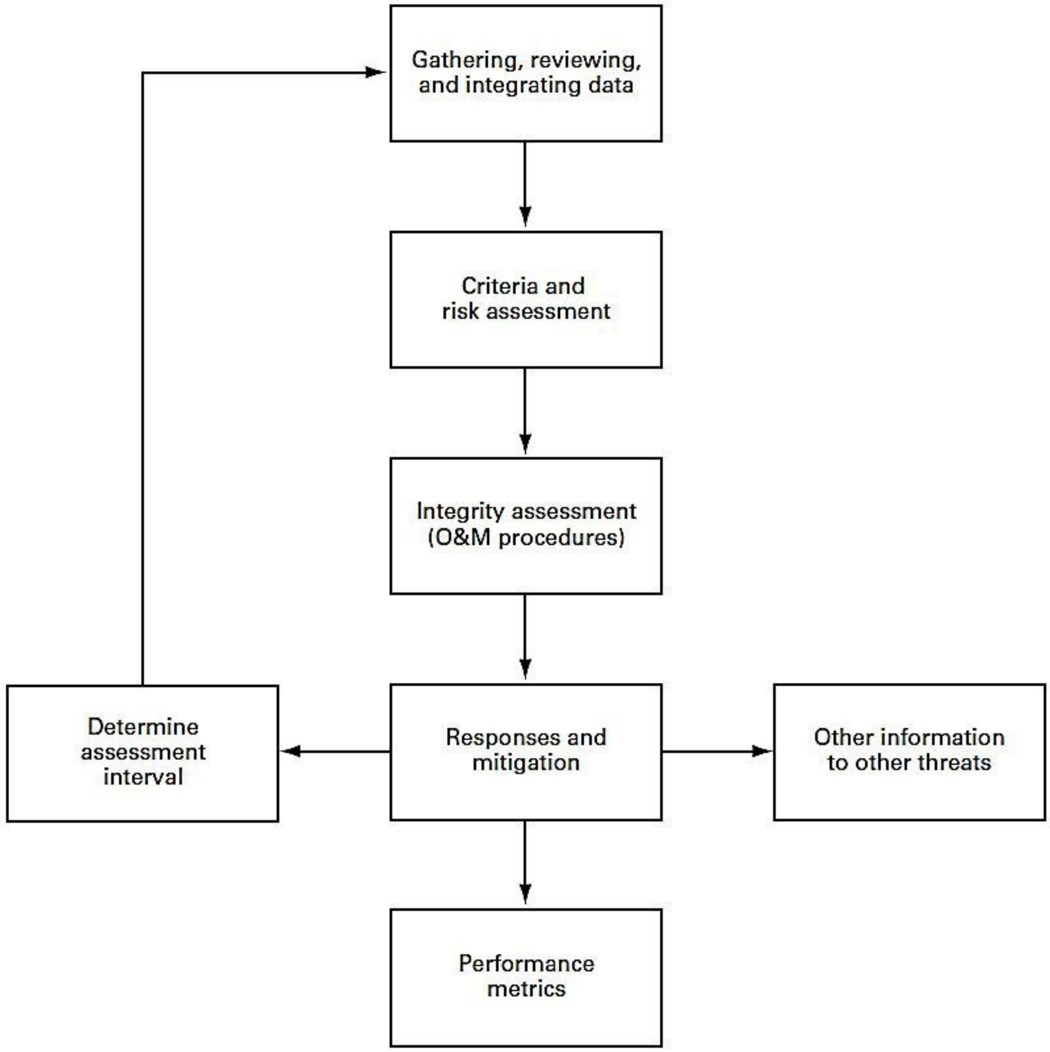
This section outlines the integrity management process for equipment in general and also covers some specific issues. Pipeline incident analysis has identified pressure control and relief equipment, gaskets and O-rings, and seal/pump packing among the causes of past incidents.

2.6.5.4.2.6.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-6.2)

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring more or additional activities.
(a) year of installation of failed equipment
(b) regulator valve failure information
(c) relief valve failure information
(d) flange gasket failure information
(e) regulator set point drift (outside of manufacturer 's tolerances)
(f) relief set point drift
(g) O-ring failure information
(h) seal/packing information

Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

Figure 2-19: Integrity Management Plan, Equipment Threat (Gasket and O-Ring, Control/Relief, Seal/Pump Packing; Simplified Process: Prescriptive) (B31.8S - Fig. A-6.1-1)



2.6.5.4.2.6.3. Criteria and Risk Assessment (B31.8S – A-6.3)

Certain relief and regulator valves are known to have their set points drift. These equipment types may require extra scrutiny.

Certain gasket types are prone to premature degradation. These equipment types may require more-frequent leak checks.

2.6.5.4.2.6.4. Integrity Assessment (B31.8S – A-6.4)

The inspections for this threat are normally conducted per the requirements of the O&M procedures. These procedures detail when inspections and maintenance of equipment shall be performed and what specific action is required. Additional or more-frequent inspections may be necessary if the equipment has a leak and failure history.

2.6.5.4.2.6.5. Responses and Mitigation (B31.8S – A-6.5)

Replacement or repair of the equipment may be required.

2.6.5.4.2.6.6. Other Data (B31.8S – A-6.6)

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when inspecting gaskets at aboveground facilities, it is discovered that there has been a lightning strike. It is appropriate to use this information when conducting risk assessments for the weather-related and outside force threat.

2.6.5.4.2.6.7. Assessment Interval (B31.8S – A-6.7)

The interval for assessment is contained within the operation and maintenance procedure for the specific types of equipment.

Changes to the segment may drive reassessment. This change management is addressed in Subsection 2.6.3.2.3.

2.6.5.4.2.6.8. Performance Measures (B31.8S – A-6.8)

The following performance measures shall be documented for the equipment threat, in order to establish the effectiveness of the program and for confirmation of the inspection interval:
(a) number of regulator valve failures
(b) number of relief valve failures
(c) number of gasket or O-ring failures
(d) number of leaks due to equipment failures

2.6.5.4.2.7 Third-Party Damage Threat [Third-Party Inflicted Damage (Immediate), Vandalism, Previously Damaged Pipe] (B31.8S – A-7)

2.6.5.4.2.7.1. Scope (B31.8S – A-7.1)

Section 2.6.5.4.2.7 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for third-party damage. Third-party damage is defined in this context as third-party inflicted damage with immediate failure, vandalism, and previously damaged pipe (see Figure 2-20).

This section outlines the integrity management process for third-party damage in general and also covers some specific issues. Pipeline incident analysis has identified third-party damage among the causes of past incidents.

2.6.5.4.2.7.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-7.2)

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring more or additional activities.
(a) vandalism incidents
(b) pipe inspection reports (bell hole) where the pipe has been hit
(c) leak reports resulting from immediate damage
(d) incidents involving previous damage
(e) in-line inspection results for dents and gouges at top half of pipe
(f) one-call records
(g) encroachment records

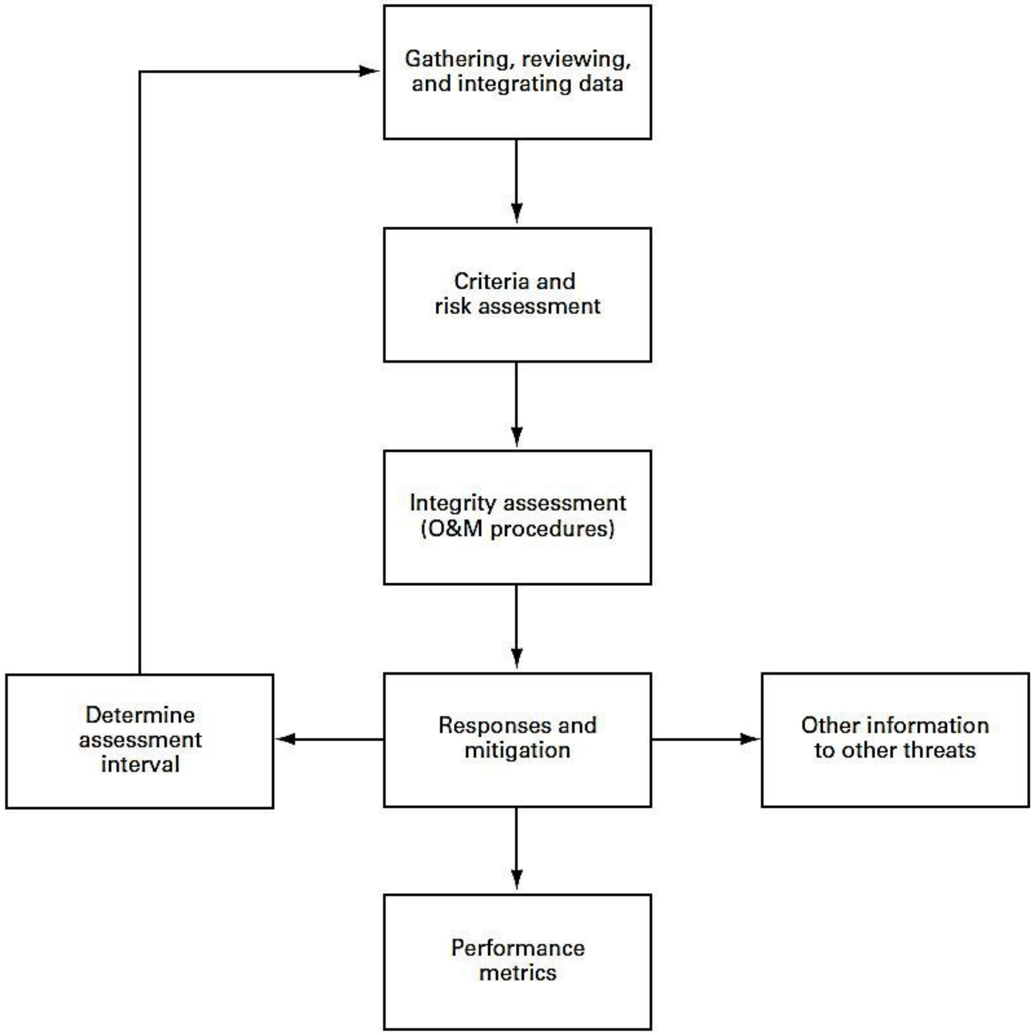
2.6.5.4.2.7.3. Criteria and Risk Assessment (B31.8S – A-7.3)

Review of data may show susceptibility to certain types of third-party inflicted damage. Deficiencies in these areas require mitigation as outlined below. Because third-party damage is a time-independent threat, even with the absence of any of these indicators, third-party damage can occur at any time and strong prevention measures are necessary, especially in areas of concern. Specific land uses, such as agricultural lands with shallow depth of cover, may be more susceptible to third-party damage.

2.6.5.4.2.7.4. Integrity Assessment (B31.8S – A-7.4)

Observance of encroachments or third-party damage is accomplished during patrols and leak surveys conducted as required by the operations and maintenance procedures. However, in the case of incidents involving previously damaged pipe, it is frequently found after the fact that the defect was revealed indirectly even though it may have been adequately described by a previous inspection such as an in-line inspection. Therefore, the operator should investigate suspicious indications discovered by inspections that cannot be directly

Figure 2-20: Integrity Management Plan, Third-Party Damage Threat (Third-Party Inflicted Damage (Immediate), Vandalism, Previously Damaged Pipe; Simplified Process: Prescriptive) (B31.8S - Fig. A-7.1-1)



2.6.5.4.2.7.5. Responses and Mitigation (B31.8S – A-7.5)

Mitigation of third-party damage is through preventive actions or repair of damage found as a result of inspections, examinations, or tests performed. The operator shall ensure that third-party damage prevention programs are in place and functioning. Additional prevention activities may be warranted as provided in Subsection 2.6.11.6.1, such as development of a damage prevention plan.

2.6.5.4.2.7.6. Other Data (B31.8S – A-7.6)

During the inspection and examination activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when monitoring an encroachment, exposed pipe may indicate active external corrosion. It is appropriate to use this information when conducting risk assessments for external corrosion.

2.6.5.4.2.7.7. Assessment Interval (B31.8S – A-7.7)

Assessment shall be performed periodically. It is recommended that it be performed annually. Changes to the segment may drive reassessment. Change management is addressed in Subsection 2.6.3.2.3.

2.6.5.4.2.7.8. Performance Measures (B31.8S – A-7.8)

The following performance measures shall be documented for the third-party threat in order to establish the effectiveness of the program and for confirmation of the inspection interval:
(a) number of leaks or failures caused by third-party damage
(b) number of leaks or failures caused by previously damaged pipe
(c) number of leaks or failures caused by vandalism
(d) number of repairs implemented as a result of third-party damage prior to a leak or failure

2.6.5.4.2.8 Incorrect Operations Threat (B31.8S – A-8)

2.6.5.4.2.8.1. Scope (B31.8S – A-8.1)

Subsection 2.6.5.4.2.8 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for incorrect operations. Incorrect operations are defined in this context as incorrect operating procedures or failure to follow a procedure (see Figure 2-21).

This section outlines the integrity management process for incorrect operations in general and also covers some specific issues. Pipeline incident analysis has identified incorrect operations among the causes of past incidents.

2.6.5.4.2.8.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-8.2)

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring more or additional activities.
(a) procedure review information
(b) audit information
(c) failures caused by incorrect operation

2.6.5.4.2.8.3. Criteria and Risk Assessment (B31.8S – A-8.3)

If the data shows the operation and maintenance are performed in accordance with operation and maintenance procedures, the procedures are correct, and that operating personnel are adequately qualified to fulfill the requirements of the procedure, no additional assessment is required. Deficiencies in these areas require mitigation as outlined below.

2.6.5.4.2.8.4. Integrity Assessment (B31.8S – A-8.4)

The audits and reviews are normally conducted on an ongoing basis. These inspections are conducted by company personnel and/or by third-party experts.

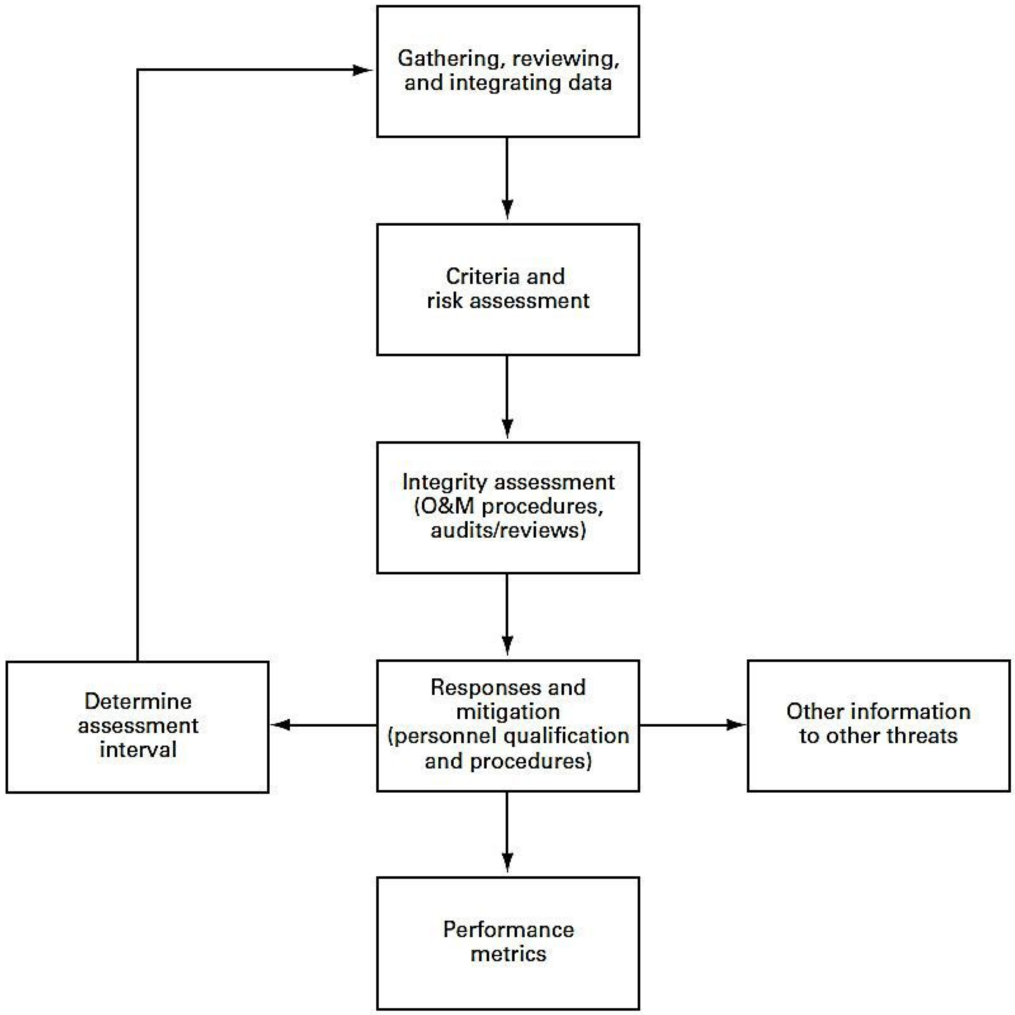
2.6.5.4.2.8.5. Responses and Mitigation (B31.8S – A-8.5)

Mitigation in this instance is prevention. The operator shall ensure that procedures are current, the personnel are adequately qualified, and that the following of procedures is enforced.

The operator should have a program to qualify operation and maintenance personnel for each activity that they perform. This program should include initial qualification and periodic reassessment of qualification. Certification by recognized organizations may be included in this program.

In addition, a strong internal review or audit program by in-house experts or third-party experts is necessary.

Figure 2-21: Integrity Management Plan, Incorrect Operations Threat (Simplified Process: Prescriptive) (B31.8S - Fig. A-8.1-1)



2.6.5.4.2.8.6. Other Data (B31.8S – A-8.6)

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

2.6.5.4.2.8.7. Assessment Interval (B31.8S – A-8.7)

Assessment shall be performed periodically and is recommended to be performed annually.
Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in Subsection 2.6.3.2.3.

2.6.5.4.2.8.8. Performance Measures (B31.8S – A-8.8)

The following performance measures shall be documented for the incorrect operations threat, in order to establish the effectiveness of the program and for confirmation of the inspection interval:
(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

2.6.5.4.2.9 Weather-Related and Outside Force Threat (Earth Movement, Heavy Rains or Floods, Cold Weather, Lightning) (B31.8S – A-9)

2.6.5.4.2.9.1. Scope (B31.8S – A-9.1)

Subsection 2.6.5.4.2.9 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for weather-related and outside force concerns. Weather-related and outside force is defined in this context as earth movement, heavy rains or floods, cold weather, and lightning (see Figure 2-22). This section outlines the integrity management process for weather-related and outside force threats in general, and also covers some specific issues. For seismic threats, PR 268-9823, Guidelines for the Seismic Design and Assessment of Natural Gas and Liquid Hydrocarbon Pipelines, or similar methodologies may be used. Pipeline incident analysis has identified weather-related and outside force damage among the causes of past incidents.

2.6.5.4.2.9.2. Gathering, Reviewing, and Integrating Data (B31.8S – A-9.2)

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. This data is collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring more or additional activities.
(a) joint method (mechanical coupling, acetylene weld, arc weld)
(b) topography and soil conditions (unstable slopes, water crossings, water proximity, soil liquefactions susceptibility)
(c) earthquake fault
(d) profile of ground acceleration near fault zones (greater than 0.2g acceleration)
(e) depth of frost line
(f) year of installation
(g) pipe grade, diameter, and wall thickness (internal stress calculation added to external loading; total stress not to exceed 100% SMYS)

Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized in a higher category based on the expected worst case of the missing data.

2.6.5.4.2.9.3. Criteria and Risk Assessment (B31.8S – A-9.3)

Pipe may be susceptible to extreme loading at the following locations:
(a) where the pipeline crosses a fault line
(b) where the pipeline traverses steep slopes
(c) where the pipeline crosses water or is adjacent to water, or where the river bottom is moving
(d) where the pipeline is subject to extreme surface loads that cause settlement to underlying soils
(e) where blasting near the pipeline is occurring
(f) when the pipe is at or above the frost line
(g) where the soil is subject to liquefaction
(h) where ground acceleration exceeds 0.2g

At locations meeting any of the above, the threat shall be evaluated. At locations where facilities are prone to lightning strikes, the threat shall be evaluated.

2.6.5.4.2.9.4. Integrity Assessment (B31.8S – A-9.4)

For weather-related and outside force threats, integrity assessments, including inspections, examinations, and evaluations, are normally conducted per the requirements of the O&M procedures. Additional or more frequent inspections may be necessary, depending on leak and failure information.

2.6.5.4.2.9.5. Responses and Mitigation (B31.8S – A-9.5)

Repairs or replacement of pipe shall be in accordance with the ASME B31.8 Code and other applicable industry standards. Other methods of mitigation may include stabilization of the soil, stabilization of the pipe or pipe joints, relocation of the pipeline, lowering of the pipeline below the frost line for cold-weather situations, and protection of aboveground facilities from lightning.

Prevention activities are most appropriate for this threat. If a pipeline falls within the listed susceptibilities, line patrolling should be used to perform surface assessments. In certain locations, such as known slide areas or areas of ongoing subsidence, the progress of the movement should be monitored.

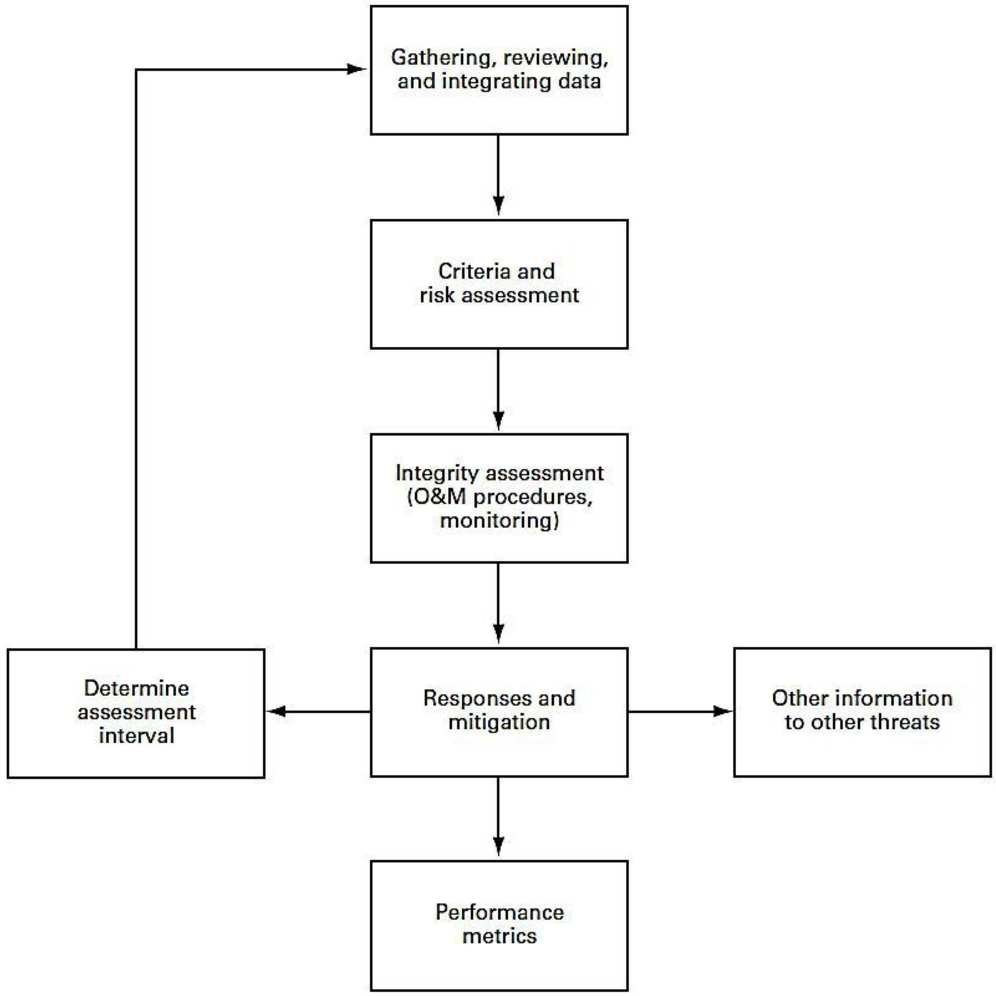
2.6.5.4.2.9.6. Other Data (B31.8S – A-9.6)

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when a pipeline is patrolled, evidence of third-party encroachment may be discovered. It is appropriate to use this information when conducting risk assessments for the third-party damage threat.

2.6.5.4.2.9.7. Assessment Interval (B31.8S – A-9.7)

Changes to the segment, or the land use around the segment, may drive reassessment if the changes affect pipeline integrity. If no changes are experienced, reassessment is not required. Change management is addressed in Subsection 2.6.3.2.3.

Figure 2-22: Integrity Management Plan, Weather-Related and Outside Force Threat (Earth Movement, Heavy Rains or Floods, Cold Weather, Lightning; Simplified Process: Prescriptive) (B31.8S - Fig. A-9.1-1)



2.6.5.4.2.9.8. Performance Measures (B31.8S – A-9.8)

The following performance measures shall be documented for the weather-related and outside force threat, in order to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks that are weather-related or due to outside force

(b) number of repair, replacement, or relocation actions due to weather-related or outside force threats

2.6.5.5 CFR Language: 192.917(c)

(c) Risk assessment - An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, Section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (192.935) for the covered segment.

2.6.5.6 ASME Standard Language

The CFR references ASME B31.8S-2012 "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 5. For user convenience, Section 5 of B31.8S has been included below.

2.6.5.6.1 Risk Assessment (B31.8S - 5)

2.6.5.6.1.1 Introduction (B31.8S - 5.1)

Risk assessments shall be conducted for pipelines and related facilities. Risk assessments are required for both prescriptive- and performance-based integrity management programs.

For prescriptive-based programs, risk assessments are primarily utilized to prioritize integrity management plan activities. They help to organize data and information to make decisions.

For performance-based programs, risk assessments serve the following purposes:
(a) to organize data and information to help operators prioritize and plan activities
(b) to determine which inspection, prevention, and/or mitigation activities will be performed and when.

2.6.5.6.1.2 Definition (B31.8S - 5.2)

The operator shall follow Subsection 2.6.5.6.1 in its entirety to conduct a performance-based integrity management program. A prescriptive-based integrity management program shall be conducted using the requirements identified in this section and in Subsection 2.6.5.4.2.

Risk is typically described as the product of two primary factors: the failure likelihood (or probability) that some adverse event will occur and the resulting consequences of that event. One method of describing risk is

$$\text{Risk}_i = P_i \times C_i \text{ for a single threat}$$

$$\text{Risk} = \sum_{i=1}^{9} P_i \times C_i \text{ for threat categories 1 to 9}$$

$$\text{Total segment risk} = P_1 \times C_1 + P_2 \times C_2 + \ldots + P_9 \times C_9$$

where

C = failure consequence
P = failure likelihood
1 to 9 = failure threat category

The risk analysis method used shall address all nine threat categories or each of the individual 21 threats to the pipeline system. Risk consequences typically consider components such as the potential impact of the event on individuals, property, business, and the environment, as shown in Subsection 2.6.1.2.1.

2.6.5.6.1.3 Risk Assessment Objectives (B31.8S - 5.3)

For application to pipelines and facilities, risk assessment has the following objectives:
(a) prioritization of pipelines/segments for scheduling integrity assessments and mitigating action
(b) assessment of the benefits derived from mitigating action
(c) determination of the most effective mitigation measures for the identified threats
(d) assessment of the integrity impact from modified inspection intervals
(e) assessment of the use of or need for alternative inspection methodologies
(f) more effective resource allocation

Risk assessment provides a measure that evaluates both the potential impact of different incident types and the likelihood that such events may occur. Having such a measure supports the integrity management process by facilitating rational and consistent decisions. Risk results are used to identify locations for integrity assessments and resulting mitigative action. Examining both primary risk factors (likelihood and consequences) avoids focusing solely on the most visible or frequently occurring problems while ignoring potential events that could cause significantly greater damage. Conversely, the process also avoids focusing on less likely catastrophic events while overlooking more likely scenarios.

2.6.5.6.1.4 Developing a Risk Assessment Approach (B31.8S - 5.4)

As an integral part of any pipeline integrity management program, an effective risk assessment process shall provide risk estimates to facilitate decision-making. When properly implemented, risk assessment methods can be very powerful analytic methods, using a variety of inputs that provide an improved understanding of the nature and locations of risks along a pipeline or within a facility.

Risk assessment methods alone should not be completely relied upon to establish risk estimates or to address or mitigate known risks. Risk assessment methods should be used in conjunction with knowledgeable, experienced personnel (subject matter experts and people familiar with the facilities) that regularly review the data input, assumptions, and results of the risk assessments. Such experience-based reviews should validate risk assessment output with other relevant factors not included in the process, the impact of assumptions, or the potential risk variability caused by missing or estimated data. These processes and their results shall be documented in the integrity management plan.

An integral part of the risk assessment process is the incorporation of additional data elements or changes to facility data. To ensure regular updates, the operator shall incorporate the risk assessment process into existing field reporting, engineering, and facility mapping processes and incorporate additional processes as required (see Subsection 2.6.3.2.3).

2.6.5.6.1.5 Risk Assessment Approaches (B31.8S - 5.5)

(a) In order to organize integrity assessments for pipeline segments of concern, a risk priority shall be established. This risk value is composed of a number reflecting the overall likelihood of failure and a number reflecting the consequences. The risk analysis can be fairly simple with values ranging from 1 to 3 (to reflect high, medium, and low likelihood and consequences) or can be more complex and involve a larger range to provide greater differentiation between pipeline segments. Multiplying the relative likelihood and consequence numbers together provides the operator with a relative risk for the segment and a relative priority for its assessment.

(b) An operator shall utilize one or more of the following risk assessment approaches consistent with the objectives of the integrity management program. These approaches are listed in a hierarchy of increasing complexity, sophistication, and data requirements. These risk assessment approaches are subject matter experts, relative assessments, scenario assessments, and probabilistic assessments. The following paragraphs describe risk assessment methods for the four listed approaches:

- *(1) Subject Matter Experts* (SMEs) - SMEs from the operating company or consultants, combined with information obtained from technical literature, can be used to provide a relative numeric value describing the likelihood of failure for each threat and the resulting consequences. The SMEs are utilized by the operator to analyze each pipeline segment, assign relative likelihood and consequence values, and calculate the relative risk.
- *(2) Relative Assessment Models* - This type of assessment builds on pipeline-specific experience and more extensive data, and includes the development of risk models addressing the known threats that have historically impacted pipeline operations. Such relative or data-based methods use models that identify and quantitatively weigh the major threats and consequences relevant to past pipeline operations. These approaches are considered relative risk models, since the risk results are compared with results generated from the same model. They provide a risk ranking for the integrity management decision process. These models utilize algorithms weighing the major

threats and consequences, and provide sufficient data to meaningfully assess them. Relative assessment models are more complex and require more specific pipeline system data than subject matter expert-based risk assessment approaches. The relative risk assessment approach, the model, and the results obtained shall be documented in the integrity management program.

(3) *Scenario-Based Models* - This risk assessment approach creates models that generate a description of an event or series of events leading to a level of risk, and includes both the likelihood and consequences from such events. This method usually includes construction of event trees, decision trees, and fault trees. From these constructs, risk values are determined.

(4) *Probabilistic Models* - This approach is the most complex and demanding with respect to data requirements. The risk output is provided in a format that is compared to acceptable risk probabilities established by the operator, rather than using a comparative basis.

It is the operator's responsibility to apply the level of integrity/risk analysis methods that meets the needs of the operator's integrity management program. More than one type of model may be used throughout an operator's system. A thorough understanding of the strengths and limitations of each risk assessment method is necessary before a long-term strategy is adopted.

(c) All risk assessment approaches described above have the following common components:
- *(1)* they identify potential events or conditions that could threaten system integrity
- *(2)* they evaluate likelihood of failure and consequences
- *(3)* they permit risk ranking and identification of specific threats that primarily influence or drive the risk
- *(4)* they lead to the identification of integrity assessment and/or mitigation options
- *(5)* they provide for a data feedback loop mechanism
- *(6)* they provide structure and continuous updating for risk reassessments

Some risk assessment approaches consider the likelihood and consequences of damage, but they do not consider whether failure occurs as a leak or rupture. Ruptures have more potential for damage than leaks. Consequently, when a risk assessment approach does not consider whether a failure may occur as a leak or rupture, a worst-case assumption of rupture shall be made.

2.6.5.6.1.6 Risk Analysis (B31.8S - 5.6)

Risk Analysis for Prescriptive Integrity Management Programs (B31.8S - 5.6.1)

The risk analyses developed for a prescriptive integrity management program are used to prioritize the pipeline segment integrity assessments. Once the integrity of a segment is established, the reinspection interval is specified in Figure 2-23. The risk analyses for prescriptive integrity management programs use minimal data sets. They cannot be used to increase the reinspection intervals.

When the operator follows the prescriptive reinspection intervals, the more simplistic risk assessment approaches provided in Subsection 2.6.5.6.1.5 are considered appropriate.

Figure 2-23: Integrity Assessment Intervals: Time-Dependent Threats, Internal and External Corrosion, Prescriptive Integrity Management Plan (B31.8S - Table 5.6.1-1)

Inspection Technique	Interval, yr [Note (1)]	Criteria: Operating Pressure Above 50% of SMYS	Criteria: Operating Pressure Above 30% But Not Exceeding 50% of SMYS	Criteria: Operating Pressure Not Exceeding 30% of SMYS
Hydrostatic testing	5	TP to 1.25 times MAOP [Note (2)]	TP to 1.39 times MAOP [Note (2)]	TP to 1.65 times MAOP [Note (2)]
	10	TP to 1.39 times MAOP [Note (2)]	TP to 1.65 times MAOP [Note (2)]	TP to 2.20 times MAOP [Note (2)]
	15	Not allowed	TP to 2.00 times MAOP [Note (2)]	TP to 2.75 times MAOP [Note (2)]
	20	Not allowed	Not allowed	TP to 3.33 times MAOP [Note (2)]
In-line inspection	5	P_f above 1.25 times MAOP [Note (3)]	P_f above 1.39 times MAOP [Note (3)]	P_f above 1.65 times MAOP [Note (3)]
	10	P_f above 1.39 times MAOP [Note (3)]	P_f above 1.65 times MAOP [Note (3)]	P_f above 2.20 times MAOP [Note (3)]
	15	Not allowed	P_f above 2.00 times MAOP [Note (3)]	P_f above 2.75 times MAOP [Note (3)]
	20	Not allowed	Not allowed	P_f above 3.33 times MAOP [Note (3)]
Direct assessment	5	All immediate indications plus one scheduled [Note (4)]	All immediate indications plus one scheduled [Note (4)]	All immediate indications plus one scheduled [Note (4)]
	10	All immediate indications plus all scheduled [Note (4)]	All immediate indications plus more than half of scheduled [Note (4)]	All immediate indications plus one scheduled [Note (4)]
	15	Not allowed	All immediate indications plus all scheduled [Note (4)]	All immediate indications plus more than half of scheduled [Note (4)]
	20	Not allowed	Not allowed	All immediate indications plus all scheduled [Note (4)]

NOTES:
(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate reassessment of the interval.
(2) TP is test pressure.
(3) P_f is predicted failure pressure as determined from ASME B31G or equivalent.
(4) For the Direct Assessment Process, indications for inspection are classified and prioritized using NACE SP0502 Pipeline External Corrosion Direct Assessment, NACE SP0206 Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA), or NACE SP0204 Stress Corrosion Cracking Direct Assessment (SCCDA) Methodology. The indications are process based and may not align with each other. For example, the External Corrosion DA indications may not be at the same location as the Internal Corrosion DA indications.

Risk Analysis for Performance-Based Integrity Management Programs (B31.8S - 5.6.2)

Performance-based integrity management programs shall prioritize initial integrity assessments utilizing any of the methods described in Subsection 2.6.5.6.1.5.

Risk analyses for performance-based integrity management programs may also be used as a basis for establishing inspection intervals. Such risk analyses will require more data elements than required in Subsection 2.6.5.4.2 and more detailed analyses. The results of these analyses may also be used to evaluate alternative mitigation and prevention methods and their timing.

An initial strategy for an operator with minimal experience using structured risk analysis methods may include adopting a more simple approach for the short term, such as knowledge-based or a screening relative risk model. As additional data and experience are gained, the operator can transition to a more comprehensive method.

2.6.5.6.1.7 Characteristics of an Effective Risk Assessment Approach (B31.8S - 5.7)

Considering the objectives summarized in Subsection 2.6.5.6.1.3, a number of general characteristics exist that will contribute to the overall effectiveness of a risk assessment for either prescriptive or performance-based integrity management programs. These characteristics shall include the following:

(a) *Attributes* - Any risk assessment approach shall contain a defined logic and be structured to provide a complete, accurate, and objective analysis of risk. Some risk methods require a more rigid structure (and considerably more input data). Knowledge-based methods are less rigorous to apply and require more input from subject-matter experts. They shall all follow an established structure and consider the nine categories of pipeline threats and consequences.

(b) *Resources* - Adequate personnel and time shall be allotted to permit implementation of the selected approach and future considerations.

(c) *Operating/Mitigation History* - Any risk assessment shall consider the frequency and consequences of past events. Preferably, this should include the subject pipeline system or a similar system, but other industry data can be used where sufficient data is initially not available. In addition, the risk assessment method shall account for any corrective or risk mitigation action that has occurred previously.

(d) *Predictive Capability* - To be effective, a risk assessment method should be able to identify pipeline integrity threats previously not considered. It shall be able to make use of (or integrate) the data from various pipeline inspections to provide risk estimates that may result from threats that have not been previously recognized as potential problem areas. Another valuable approach is the use of trending, where the results of inspections, examinations, and evaluations are collected over time in order to predict future conditions.

(e) *Risk Confidence* - Any data applied in a risk assessment process shall be verified and checked for accuracy (see Subsection 2.6.3.2.4). Inaccurate data will produce a less accurate risk result. For missing or questionable data, the operator should determine and document the default values that will be used and why they were chosen. The operator should choose default values that conservatively reflect the values of other similar segments on the pipeline or in the operator's system. These conservative values may elevate the risk of the pipeline and encourage action to obtain accurate data. As the data are obtained, the uncertainties will be eliminated and the resultant risk values may be reduced.

(f) *Feedback* - One of the most important steps in an effective risk analysis is feedback. Any risk assessment method shall not be considered as a static tool, but as a process of continuous improvement. Effective feedback is an essential process component in continuous risk model validation. In addition, the model shall be adaptable and changeable to accommodate new threats.

(g) *Documentation* - The risk assessment process shall be thoroughly and completely documented, to provide the background and technical justification for the methods and procedures used and their impact on decisions based on the risk estimates. Like the risk process itself, such a document should be periodically updated as modifications or risk process changes are incorporated.

(h) *"What if" Determinations* - An effective risk model should contain the structure necessary to perform "what if" calculations. This structure can provide estimates of the effects of changes over time and the risk reduction benefit from maintenance or remedial actions.

(i) *Weighting Factors* - All threats and consequences contained in a relative risk assessment process should not have the same level of influence on the risk estimate. Therefore, a structured set of weighting factors shall be included that indicate the value of each risk assessment component, including both failure probability and consequences. Such factors can be based on operational experience, the opinions of subject matter experts, or industry experience.

(j) *Structure* - Any risk assessment process shall provide, as a minimum, the ability to compare and rank the risk results to support the integrity management program's decision process. It should also provide for several types of data evaluation and comparisons, establishing which particular threats or factors have the most influence on the result. The risk assessment process shall be structured, documented, and verifiable.

(k) *Segmentation* - An effective risk assessment process shall incorporate sufficient resolution of pipeline segment size to analyze data as it exists along the pipeline. Such analysis will facilitate location of local high-risk areas that may need immediate attention. For risk assessment purposes, segment lengths can range from units of feet to miles (m to km), depending on the pipeline attributes, its environment, and other data.

Another requirement of the model involves the ability to update the risk model to account for mitigation or other action that changes the risk in a particular length. This can be illustrated by assuming that two adjacent mile-long (1.6 km-long) segments have been identified. Suppose a pipe replacement is completed from the midpoint of one segment to some point within the other. In order to account for the risk reduction, the pipeline length comprising these two segments now becomes four risk analysis segments. This is called dynamic segmentation.

2.6.5.6.1.8 Risk Estimates Using Assessment Methods (B31.8S - 5.8)

A description of various details and complexities associated with different risk assessment processes has been provided in Subsection 2.6.5.6.1.5. Operators that have not previously initiated a formal risk assessment process may find an initial screening to be beneficial. The results of this screening can be implemented within a short time frame and focus given to the most important areas. A screening risk assessment may not include the entire pipeline system, but be limited to areas with a history of problems or where failure could result in the most severe consequences, such as areas of concern. Risk assessment and data collection may then be focused on the most likely threats without requiring excessive detail. A screening risk assessment suitable for this approach can include subject matter experts or simple relative risk models as described in Subsection 2.6.5.6.1.5. A group of subject-matter experts representing pipeline operations, engineering, and others knowledgeable of threats that may exist is assembled to focus on the potential threats and risk reduction measures that would be effective in the integrity management program.

Application of any type of risk analysis methodology shall be considered as an element of continuous process and not a one-time event. A specified period defined by the operator shall be established for a system-wide risk reevaluation, but shall not exceed the required maximum interval in Figure 2-23. Segments containing indications that are scheduled for examination or that are to be monitored must be assessed within time intervals that will maintain system integrity. The frequency of the system-wide reevaluation must be at least annually, but may be more frequent, based on the frequency and importance of data modifications. Such a reevaluation should include all pipelines or segments included in the risk analysis process, to ensure that the most recent inspection results and information are reflected in the reevaluation and any risk comparisons are on an equal basis.

The processes and risk assessment methods used shall be periodically reviewed to ensure they continue to yield relevant, accurate results consistent with the objectives of the operator's overall integrity management program. Adjustments and improvements to the risk assessment methods will be necessary as more complete and accurate information concerning pipeline system attributes and history becomes available. These adjustments shall require a reanalysis of the pipeline segments included in the integrity management program, to ensure that equivalent assessments or comparisons are made.

2.6.5.6.1.9 Data Collection for Risk Assessment (B31.8S - 5.9)

Data collection issues have been discussed in Subsection 2.6.5.4.1. When analyzing the results of the risk assessments, the operator may find that additional data is required. Iteration of the risk assessment process may be required to improve the clarity of the results, as well as confirm the reasonableness of the results.

Determining the risk of potential threats will result in specification of the minimum data set required for implementation of the selected risk process. If significant data elements are not available, modifications of the proposed model may be required after carefully reviewing the impact of missing data and taking into account the potential effect of uncertainties created by using required estimated values. An alternative could be to use related data elements in order to make an inferential threat estimate.

2.6.5.6.1.10 Prioritization for Prescriptive-Based and Performance-Based Integrity Management Programs (B31.8S - 5.10)

A first step in prioritization usually involves sorting each particular segment's risk results in decreasing order of overall risk. Similar sorting can also be achieved by separately considering decreasing consequences or failure probability levels. The highest risk level segment shall be assigned a higher priority when deciding where to implement integrity assessment and/or mitigation actions. Also, the operator should assess risk factors that cause higher risk levels for particular segments. These factors can be applied to help select, prioritize, and schedule locations for inspection actions such as hydrostatic testing, in-line inspection, or direct assessment. For example, a pipeline segment may rank extremely high for a single threat, but rank much lower for the aggregate of threats compared to all other pipeline segments. Timely resolution of the single highest threat segment may be more appropriate than resolution of the highest aggregate threat segment.

For initial efforts and screening purposes, risk results could be evaluated simply on a "high–medium–low" basis or as a numerical value. When segments being compared have similar risk values, the failure probability and consequences should be considered separately. This may lead to the highest consequence segment being given a higher priority. Factors including line availability and system throughput requirements can also influence prioritization.

The integrity plan shall also provide for the elimination of any specific threat from the risk assessment. For a prescriptive integrity management program, the minimum data required and the criteria for risk assessment in order to eliminate a threat from further consideration are specified in Subsection 2.6.5.4.2. Performance-based integrity management programs that use more comprehensive analysis methods should consider the following in order to exclude a threat in a segment:

(a) there is no history of a threat impacting the particular segment or pipeline system
(b) the threat is not supported by applicable industry data or experience
(c) the threat is not implied by related data elements
(d) the threat is not supported by like/similar analyses
(e) the threat is not applicable to system or segment operating conditions

More specifically, para. (c) considers the application of related data elements to provide an indication of a threat's presence when other data elements may not be available. As an example, for the external corrosion threat, multiple data elements such as soil type/moisture level, CP data, CIS data, CP current demand, and coating condition can all be used, or if one is unavailable a subset may be sufficient to determine whether the threat shall be considered for that segment. Paragraph (d) considers the evaluation of pipeline segments with known and similar conditions that can be used as a basis for evaluating the existence of threats on pipelines with missing data. Paragraph (e) allows for the fact that some pipeline systems or segments are not vulnerable to some threats. For instance, based on industry research and experience, pipelines operating at low stress levels do not develop SCC-related failures.

The unavailability of identified data elements is not a justification for exclusion of a threat from the integrity management program. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required. In addition, a threat cannot be excluded without consideration given to the likelihood of interaction by other threats. For instance, cathodic protection shielding in rocky terrain where impressed current may not prevent corrosion in areas of damaged coating must be considered.

When considering threat exclusion, a cautionary note applies to threats classified as time-dependent. Although such an event may not have occurred in any given pipeline segment, system, or facility, the fact that the threat is considered time-dependent should require very strong justification for its exclusion. Some threats, such as internal corrosion and SCC, may not be immediately evident and can become a significant threat even after extended operating periods.

2.6.5.6.1.11 Integrity Assessment and Mitigation (B31.8S - 5.11)

The process begins with examining the nature of the most significant risks. The risk drivers for each high-risk segment should be considered in determining the most effective integrity assessment and/or mitigation option. Subsection 2.6.11.6.1 discusses integrity assessment and Subsection 2.6.11.6.1 discusses options that are commonly used to mitigate threats. A recalculation of each segment's risk after integrity assessment and/or mitigation actions is required to ensure that the segment's integrity can be maintained to the next inspection interval.

It is necessary to consider a variety of options or combinations of integrity assessments and mitigation actions that directly address the primary threat(s). It is also prudent to consider the possibility of using new technologies that can provide a more effective or comprehensive risk mitigation approach.

2.6.5.6.1.12 Validation (B31.8S - 5.12)

Validation of risk analysis results is one of the most important steps in any assessment process. This shall be done to ensure that the methods used have produced results that are usable and are consistent with the operator's and industry's experience. A reassessment of and modification to the risk assessment process shall be required if, as a result of maintenance or other activities, areas are found that are inaccurately represented by the risk assessment process. A risk validation process shall be identified and documented in the integrity management program.

Risk result validations can be successfully performed by conducting inspections, examinations, and evaluations at locations that are indicated as either high risk or low risk, to determine if the methods are correctly characterizing the risks. Validation can be achieved by considering another location's information regarding the condition of a pipeline segment and the condition determined during maintenance action or prior remedial efforts. A special risk assessment performed using known data prior to the maintenance activity can indicate if meaningful results are being generated.

2.6.5.7 CFR Language: 192.917(e)(1)

(e) *Actions to address particular threats* - If an operator identifies any of the following threats, the operator must take the following actions to address the threat.
   (1) *Third party damage* - An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with 192.921, or a reassessment under 192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

2.6.5.8 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Appendix A7. Appendix A7 of B31.8S may be found in the Subsection 2.6.5.4.2.7.

2.6.5.9 CFR Language: 192.917(e)(4)

(e) Actions to address particular threats - If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(4) ERW pipe - If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

2.6.5.10 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section A4.3 and A4.4. Appendix A4 of B31.8S may be found in Subsection 2.6.5.4.2.4.

2.6.6 CFR Reference: 192.921 How is the Baseline Assessment to be Conducted?

2.6.6.1 CFR Language: 192.921(a)(1)

(a) Assessment methods - An operator must assess the integrity of the line pipe in each covered segment by applying one of more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See 192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

2.6.6.2 ASME Standard Language:

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.2. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2.

2.6.7 CFR Reference: 192.923 How is Direct Assessment Used and for What Threats?

2.6.7.1 CFR Language: 192.923(b)(1)

(b) Primary method - An operator direct assessment as a primary assessment method must have a plan that complies with the requirements in –

(1) ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 6.4; NACE SP0502-2008 (incorporated by reference, see 192.7); and 192.925 if addressing external corrosion (ECDA).

2.6.7.2 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.4 and Appendix B2. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2. Appendix B2 of B31.8S may be found in Subsection 2.6.7.4.1.

2.6.7.3 CFR Language: 192.923(b)(2)

(b) Primary method - An operator direct assessment as a primary assessment method must have a plan that complies with the requirements in –
  (2) ASME/ANSI B31.8S, Section 6.4 and appendix B2, and 192.927 if addressing internal corrosion (ICDA).

2.6.7.4 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.4 and Appendix B2. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2. Appendix B2 may be found immediately below.

2.6.7.4.1 Internal Corrosion Direct Assessment (B31.8S – B2)

This section has been removed with publication of NACE SP0206 DG-ICDA. Operators are encouraged to use NACE SP0206 DG-ICDA or an alternate and technically justified methodology.

2.6.7.5 CFR Language: 192.923(b)(3)

(b) Primary method - An operator direct assessment as a primary assessment method must have a plan that complies with the requirements in –
  (3) ASME/ANSI B31.8S, appendix A3, and 192.929 if addressing stress corrosion cracking (SCCDA).

2.6.7.6 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Appendix A3. Appendix A3 of B31.8S may be found in Subsection 2.6.5.4.2.3.

2.6.8 CFR Reference: 192.925 What are the Requirements for Using External Corrosion Direct Assessment (ECDA)?

2.6.8.1 CFR Language: 192.925(b) Introductory text

(b) General requirements - An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 6.4, and in NACE SP0502-2008 (incorporated by reference, see 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by 192.917(e)(1).

2.6.8.2 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.4. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2.

2.6.8.3 CFR Language: 192.925(b)(1)

(b) General requirements - An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 6.4, and in NACE SP0502-2008 (incorporated by reference, see 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating

damage, the operator must also integrate the data from the ECDA with other information from the data integration (192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by 192.917(e)(1).

(1) Preassessment - In addition to the requirements in ASME/ANSI B31.8S Section 6.4 and NACE SP0502-2008, Section 3, the plan's procedures for preassessment must include –

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502-2008, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

2.6.8.4 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.4. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2.

2.6.8.5 CFR Language: 192.925(b)(2)

(b) General requirements - An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 6.4, and in NACE SP0502-2008 (incorporated by reference, see 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by 192.917(e)(1).

(2) Indirect examination - In addition to the requirements in ASME/ANSI B31.8S Section 6.4 and NACE SP0502-2008, Section 4, the plan's procedures for indirect examination of the ECDA regions must include –

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

2.6.8.6 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.4. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2.

2.6.8.7 CFR Language: 192.925(b)(3)

(b) General requirements - An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 6.4, and in NACE SP0502-2008 (incorporated by reference, see 192.7). An operator

must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by 192.917(e)(1).

(3) Direct examination - In addition to the requirements in ASME/ANSI B31.8S Section 6.4 and NACE SP0502-2008, Section 5, the plan's procedures for direct examination of indications from the indirect examination must include –

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

- Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE SP0502-2008), or
- Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502-2008);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in Section 5.9 of NACE SP0502-2008.

2.6.8.8 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.4. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2.

2.6.8.9 CFR Language: 192.925(b)(4)

(b) General requirements - An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 6.4, and in NACE SP0502-2008 (incorporated by reference, see 192.7). An operator must develop and implement a direct assessment plan that has procedures addressing preassessment, indirect examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by 192.917(e)(1).

(4) Post assessment and continuing evaluation - In addition to the requirements in ASME/ANSI B31.8S Section 6.4 and NACE SP0502-2008, Section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include –

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in 192.939. (See Appendix D of NACE SP0502-2008.)

2.6.8.10 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.4. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2.

2.6.9 CFR Reference: 192.927 What are the Requirements for Using Internal Corrosion Direct Assessment (ICDA)?

2.6.9.1 CFR Language: 192.927(b)

(b) *General requirements* - An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ASNI B31.8S (incorporated by reference, see 192.7), Section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with 192.921(a)(4) or 192.937(c)(4).

2.6.9.2 ASME Standard Language

The CFR references ASME/B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.4 and Appendix B2. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2. Appendix B2 of B31.8S may be found in Subsection 2.6.7.4.1.

2.6.9.3 CFR Language: 192.927(c)(1)(i)

(c) *The ICDA plan* - An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation location, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.
  (1) *Preassessment* - In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to –
    (i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

2.6.9.4 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Appendix A2 & A3 in their entireties. Appendix A of B31.8S may be found in Subsection 2.6.5.4.2.

2.6.10 CFR Reference: 192.929 What are the Requirements for Using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

2.6.10.1 CFR Language: 192.929(b)(2)

(b) *General requirements* - An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for –
  (2) *Assessment method* - The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

2.6.10.2 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Appendix A3. Appendix A3 of B31.8S may be found in Subsection 2.6.5.4.2.3.

2.6.11 CFR Reference: 192.933 What Actions Must Be Taken to Address Integrity Issues? (192.933(a), (d)(1), (d)(1)(i))

2.6.11.1 CFR Language: 192.933(a)

(a) General requirements - An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

2.6.11.2 ASME Standard Reference

The CFR references ASME B31G "Manual for Determining the Remaining Strength of Corroded Pipelines" in its entirety.

2.6.11.3 CFR Language

(c) Schedule for evaluation and remediation - An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

2.6.11.4 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 7, Figure A-7.1-1. Section 7, Figure A-7.1-1 of B31.8S may be found in Figure 9.

2.6.11.5 CFR Language: 192.933(d)(1)

(d) Special requirements for scheduling remediation – (1) *Immediate repair conditions* - An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

2.6.11.6 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 7. For user convenience, Section 7 of B31.8S has been included below.

2.6.11.6.1 Responses to Integrity Assessments and Mitigation (Repair and Prevention) (B31.8S –7)

2.6.11.6.1.1 General (B31.8S –7.1)

This section covers the schedule of responses to the indications obtained by inspection (see Section 6), repair activities that can be affected to remedy or eliminate an unsafe condition, preventive actions that can be taken to reduce or eliminate a threat to the integrity of a pipeline, and establishment of the inspection interval. Inspection intervals are based on the characterization of defect indications, the level of mitigation achieved, the prevention methods employed, and the useful life of the data, with consideration given to expected defect growth.

Examination, evaluation, and mitigative actions shall be selected and scheduled to achieve risk reduction where appropriate in each segment within the integrity management program.

The integrity management program shall provide analyses of existing and newly implemented mitigation actions to evaluate their effectiveness and justify their use in the future.

Figure 2-24 includes a summary of some prevention and repair methods and their applicability to each threat.

2.6.11.6.1.2 Responses to Pipeline In-Line Inspections (B31.8S - 7.2)

An operator shall complete the response according to a prioritized schedule established by considering the results of a risk assessment and the severity of in-line inspection indications. The required response schedule interval begins at the time the condition is discovered. When establishing schedules, responses can be divided into the following three groups:
(a) immediate: indication shows that defect is at failure point
(b) scheduled: indication shows defect is significant but not at failure point
(c) monitored: indication shows defect will not fail before next inspection

Upon receipt of the characterization of indications discovered during a successful in-line inspection, the operator shall promptly review the results for immediate response indications. Other indications shall be reviewed within 6 months and a response plan shall be developed. The plan shall include the methods and timing of the response (examination and evaluation). For scheduled or monitored responses, an operator may re-inspect rather than examine and evaluate, provided the reinspection is conducted and results obtained within the specified time frame.

Metal Loss Tools for Internal and External Corrosion. (B31.8S - 7.2.1)

Indications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. This would include any corroded areas that have a predicted failure pressure level less than 1.1 times the MAOP as determined by ASME B31G or equivalent. Also in this group would be any metal-loss indication affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding. The operator shall take action on these indications by either examining them or reducing the operating pressure to provide an additional margin of safety, within a period not to exceed 5 days following determination of the condition. If the examination cannot be completed within the required 5 days, the operator shall temporarily reduce the operating pressure until the indication is examined. Figure 2-25 shall be used to determine the reduced operating pressure based on the selected response time. After examination and evaluation, any defect found to require repair or removal shall be promptly remediated by repair or removal unless the operating pressure is lowered to mitigate the need to repair or remove the defect.

Indications in the scheduled group are suitable for continued operation without immediate response provided they do not grow to critical dimensions prior to the scheduled response. Indications characterized with a predicted failure pressure greater than 1.10 times the MAOP shall be examined and evaluated according to a schedule established by Figure 2-25. Any defect found to require repair or removal shall be promptly remediated by repair or removal unless the operating pressure is lowered to mitigate the need to repair or remove the defect.

Monitored indications are the least severe and will not require examination and evaluation until the next scheduled integrity assessment interval stipulated by the integrity management plan, provided that they are not expected to grow to critical dimensions prior to the next scheduled assessment.

Crack Detection Tools for Stress Corrosion Cracking. (B31.8S - 7.2.2)

It is the responsibility of the operator to develop and document appropriate assessment, response, and repair plans when in-line inspection (ILI) is used for the detection and sizing of indications of stress corrosion cracking (SCC).

In lieu of developing assessment, response, and repair plans, an operator may elect to treat all indications of stress corrosion cracks as requiring immediate response, including examination or pressure reduction within a period not to exceed 5 days following determination of the condition.

After examination and evaluation, any defect found to require repair or removal shall be promptly remediated by repair, removal, or lowering the operating pressure until such time as removal or repair is completed.

Metal Loss and Caliper Tools for Third-Party Damage and Mechanical Damage. (B31.8S - 7.2.3)

Indications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. These could include dents with gouges. The operator shall examine these indications within a period not to exceed 5 days following determination of the condition.

Indications requiring a scheduled response would include any indication on a pipeline operating at or above 30% of specified minimum yield strength (SMYS) of a plain dent that exceeds 6% of the nominal pipe diameter, mechanical damage with or without concurrent visible indentation of the pipe, dents with cracks, dents that affect ductile girth or seam welds if the depth is in excess of 2% of the nominal pipe diameter, and dents of any depth that affect nonductile welds. (For additional information, see ASME B31.8, para. 851.4.). The operator shall expeditiously examine these indications within a period not to exceed 1 year following determination of the condition. After examination and evaluation, any defect found to require repair or removal shall be promptly remediated by repair or removal, unless the operating pressure is lowered to mitigate the need to repair or remove the defect.

Limitations to Response Times for Prescriptive-Based Program. (B31.8S - 7.2.4)

When time-dependent anomalies such as internal corrosion, external corrosion, or stress corrosion cracking are being evaluated, an analysis utilizing appropriate assumptions about growth rates shall be used to ensure that the defect will not attain critical dimensions prior to the scheduled repair or next inspection. GRI-00/0230 contains additional guidance for these analyses

Figure 2-24: Summary of some prevention and repair methods and their applicability to each threat (B31.8S - Table 7.1-1)

Prevention, Detection, and Repair Methods	Third-Party Damage			Corrosion Related		Equipment				Incorrect Operation	Weather Related			Manufacture		Construction				O-Force	Environ-ment
	TPD(IF)	PDP	Vand	Ext	Int	Gask/ Oring	Strip/ BP	Cont/ Rel	Seal/ Pack	IO	CW	L	HR/F	Pipe Seam	Pipe	Gweld	Fab Weld	Coup	WB/B	EM	SCC
Prevention/Detection																					
Aerial patrol	X	X	X	...	...	...	...	...	...	...	X	X	X	...	...	...	...	X	...	X	...
Foot patrol	X	X	X	X	...	...	...	...	...	...	X	X	X	...	...	...	...	X	...	X	...
Visual/mechanical inspection	...	...	...	...	...	X	X	X	X	...	X	...	...	...	...	X	...	...	...	...	...
One call system	X	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Compliance audit	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...
Design specifications	...	...	...	X	X	X	X	X	X	...	...	...	...	...	...	X	...	X	X	X	X
Materials specifications	...	...	...	...	...	X	X	X	X	...	X	...	X	X	X	...	X	...	...	...	...
Manufacturer inspection	...	X	...	...	...	...	...	X	X	...	...	...	...	X	X	...	X	...	...	...	...
Transportation inspection	...	X	...	...	...	...	...	...	...	...	...	...	...	X	X	...	...	...	...	...	...
Construction inspection	...	X	...	X	...	X	X	X	X	...	...	...	...	...	X	X	X	X	X	...	X
Preservice pressure test	...	X	...	...	...	...	...	...	...	...	...	...	...	X	X	X	X	X	X	...	...
Public education	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
O&M procedures	X	X	X	X	X	X	X	X	X	X	X	...	X	...	...	...	...	X	X	X	X
Operator training	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...
Increase marker frequency	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Strain monitoring	...	...	...	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	X	...
External protection	X	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X	...
Maintain ROW	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X	...
Increased wall thickness	X	X	X	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X	...
Warning tape mesh	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
CP monitor/maintain	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X
Internal cleaning	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Leakage control measures	...	X	X	X	X	X	X	X	X	...	...	...	...	...	...	...	...	X	...	...	...
Pig-GPS/strain measurement	...	...	...	...	...	...	...	...	...	...	X	...	X	...	...	...	...	...	...	X	...
Reduce external stress	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	X	X	X	X
Install heat tracing	...	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...
Line relocation	X	...	X	...	...	...	...	...	...	...	X	...	X	...	...	...	...	...	...	X	...
Rehabilitation	...	X	...	X	X	...	...	...	...	...	...	...	...	...	...	...	...	X	X	X	X
Coating repair	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X
Increase cover depth	X	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X	...	...
Operating temperature reduction	...	...	...	...	...	X	...	...	X	...	...	...	...	...	...	...	...	...	...	...	X
Reduce moisture	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Biocide/inhibiting injection	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Install thermal protection	...	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...
Repairs																					
Pressure reduction	...	X	...	X	X	X	...	...	...	...	...	...	...	X	X	X	X	X	...	...	X
Replacement	X	X	X	X	X	X	X	X	X	...	X	X	X	X	X	X	X	X	X	X	X
ECA, recoat	...	...	...	X	X	...	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...
Grind repair/ECA	...	X	X	...	...	...	...	...	...	...	...	...	...	X	X	X	X	...	...	...	X
Direct deposition weld	...	C	C	C	C	...	...	...	...	...	...	...	...	C	C	C	C	...	...	...	...

Figure 2-24 - Summary of some prevention and repair methods and their applicability to each threat (B31.8S - Table 7.1-1) (cont.)

Prevention, Detection, and Repair Methods	Third-Party Damage			Corrosion Related		Equipment				Incorrect Operation	Weather Related			Manufacture		Construction				O-Force	Environment
	TPD(IF)	PDP	Vand	Ext	Int	Gask/Oring	Strip/BP	Cont/Rel	Seal/Pack	IO	CW	L	HR/F	Pipe Seam	Pipe	Gweld	Fab Weld	Coup	WB/B	EM	SCC
Repairs (Cont'd)																					
Type B, pressurized sleeve	...	X	X	X	X	...	...	...	...	...	...	...	...	X	X	X	X	X	...	...	X
Type A, reinforcing sleeve	...	X	X	X	...	...	...	...	...	...	...	...	...	X	X	X	A/D	...	...	...	X
Composite sleeve	...	D	D	X	...	...	...	...	...	...	...	...	...	X	X	X	A	...	...	...	...
Epoxy filled sleeve	...	X	X	X	...	...	...	...	...	...	...	...	...	X	X	X	A	X	X	C	...
Annular filled saddle	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	B	...	...	...	...
Mechanical leak clamp	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	A	...	...	...	...

Key

X = acceptable

... = unacceptable

A = these may be used to repair straight pipe but may not be used to repair branch and T joints.

B = these may be used to repair branch and T joints but may not be used to repair straight pipe.

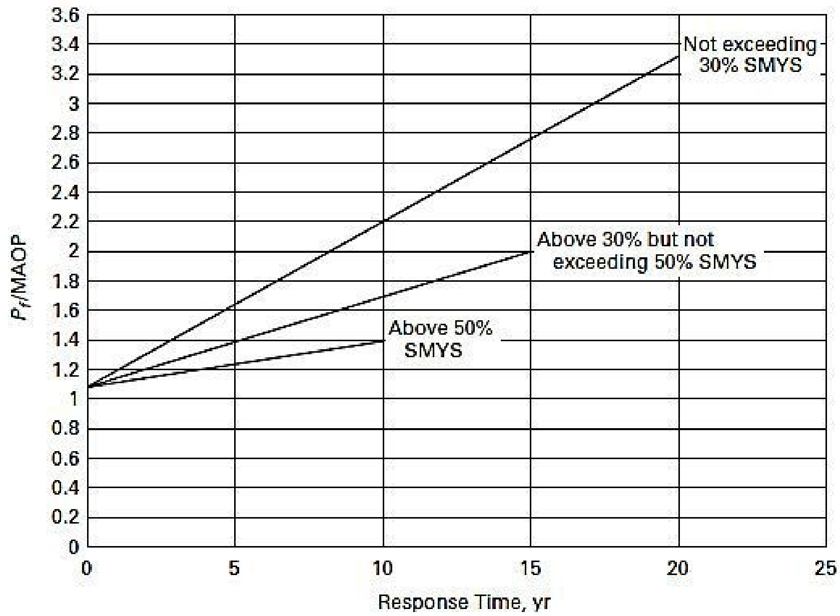
C = the materials, weld procedures, and pass sequences need to be properly designed and correctly applied to ensure cracking is avoided. Particular care must be exercised to ensure the safety of workers when welding on pressurized lines. Guidance can be found in publications by W.A. Bruce, et al., IPC2002-27131, IPC2006-10299, and IPC 2008-64353.

D = this repair is not intended to restore axial pipe strength. It can only be used for damaged pipe where all the stress risers have been ground out and the missing wall is filled with uncompressible filler. Transitions at girth welds, fittings, and to heavy wall pipe require additional care to ensure the hoop carrying capacity is effectively restored.

GENERAL NOTE: The abbreviations found in Table 7.1-1 relate to the 21 threats discussed in section 5. Explanations of the abbreviations are as follows:

Cont/Rel = control/relief equipment malfunction
Coup = coupling failure
CW = cold weather
Direct deposition weld = a very specialized repair technique that requires detailed materials information and procedure validation to avoid possible cracking on live lines
ECA = engineering critical assessment
EM = Earth movement
Ext = external corrosion
Fab Weld = defective fabrication weld including branch and T joints
Gask/Oring = gasket or O-ring
Gweld = defective pipe girth weld (circumferential)
HR/F = heavy rains or floods
Int = internal corrosion
IO = incorrect operations
L = lightning
PDP = previously damaged pipe (delayed failure mode such as dents and/or gouges) (previously damaged pipe); see ASME B31.8 para. 851.4.2 and Nonmandatory Appendix R-2.
Pipe = defective pipe
Pipe Seam = defective pipe seam
SCC = stress corrosion cracking
Seal/Pack = seal/pump packing failure
Strip/BP = stripped thread/broken pipe
TPD(IF) = damage inflicted by first, second, or third parties (instantaneous/immediate failure)
Vand = vandalism
WB/B = wrinkle bend or buckle

Figure 2-25: Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan (B31.8S - Fig. 7.2.1-1)



GENERAL NOTE: Predicted failure pressure, P_f, is calculated using a proven engineering method for evaluating the remaining strength of corroded pipe. The failure pressure ratio is used to categorize a defect as immediate, scheduled, or monitored.

When determining repair intervals, the operator should consider that certain threats to specific pipeline operating conditions may require a reduced examination and evaluation interval. This may include third-party damage or construction threats in pipelines subject to pressure cycling or external loading that may promote increased defect growth rates. For prescriptive-based programs, the inspection intervals are conservative for potential defects that could lead to a rupture; however, this does not alleviate operators of the responsibility to evaluate the specific conditions and changes in operating conditions to ensure the pipeline segment does not warrant special consideration (see GRI-01/0085).

If the analysis shows that the time to failure is too short in relation to the time scheduled for the repair, the operator shall apply temporary measures, such as pressure reduction, until a permanent repair is completed. In considering projected repair intervals and methods, the operator should consider potential delaying factors, such as access, environmental permit issues, and gas supply requirements.

Extending Response Times for Performance-Based Program. (B31.8S - 7.2.5)

An engineering critical assessment (ECA) of some defects may be performed to extend the repair or reinspection interval for a performance-based program. ECA is a rigorous evaluation of the data that reassesses the criticality of the anomaly and adjusts the projected growth rates based on site-specific parameters.

The operator's integrity management program shall include documentation that describes grouping of specific defect types and the ECA methods used for such analyses.

2.6.11.6.1.3 Responses to Pressure Testing (B31.8S - 7.3)

Any defect that fails a pressure test shall be promptly remediated by repair or removal.

External and Internal Corrosion Threats. (B31.8S - 7.3.1)

The interval between tests for the external and internal corrosion threats shall be consistent with Figure 2-24.

Stress Corrosion Cracking Threat. (B31.8S - 7.3.2)

The interval between pressure tests for stress corrosion cracking shall be as follows:

(a) If no failures occurred due to SCC, the operator shall use one of the following options to address the long-term mitigation of SCC:
   (1) a documented hydrostatic retest program with a technically justifiable interval or
   (2) an engineering critical assessment to evaluate the risk and identify further mitigation methods

(b) If a failure occurred due to SCC, the operator shall perform the following:
   (1) implement a documented hydrostatic retest program for the subject segment and
   (2) technically justify the retest interval in the written retest program

Manufacturing and Related Defect Threats. (B31.8S - 7.3.3)

A subsequent pressure test for the manufacturing threat is not required unless the MAOP of the pipeline has been raised or when the operating pressure has been raised above the historical operating pressure (highest pressure recorded in 5 years prior to the effective date of this supplement).

2.6.11.6.1.4 Responses to Direct Assessment Inspections (B31.8S - 7.4)

External Corrosion Direct Assessment (ECDA). (B31.8S - 7.4.1)

For the ECDA prescriptive program for pipelines operating above 30% SMYS, if the operator chooses to examine and evaluate all the indications found by inspection, and repairs all defects that could grow to failure in 10 years, then the reinspection interval shall be 10 years. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 5 years, provided an analysis is performed to ensure all remaining defects will not grow to failure in 10 years. The interval between determination and examination shall be consistent with Figure 2-25.

For the ECDA prescriptive program for pipeline segments operating up to but not exceeding 30% SMYS, if the operator chooses to examine and evaluate all the indications found by inspections and repair all defects that could grow to failure in 20 years, the reinspection interval shall be 20 years. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 10 years, provided an analysis is performed to ensure all remaining defects will not grow to failure in 20 (at an 80% confidence level). The interval between determination and examination shall be consistent with Figure 2-25.

Internal Corrosion Direct Assessment (ICDA). (B31.8S - 7.4.2)

For the ICDA prescriptive program, examination and evaluation of all selected locations must be performed within 1 year of selection. The interval between subsequent examinations shall be consistent with Figure 2-25.

Stress Corrosion Cracking Direct Assessment (SCCDA). (B31.8S - 7.4.3)

For the SCCDA prescriptive program, examination and evaluation of all selected locations must be performed within 1 year of selection. ILI or pressure testing (hydrotesting) may not be warranted if significant and extensive cracking is not present on a pipeline system. The interval between subsequent examinations shall provide similar safe interval between periodic integrity assessments consistent with Figure 2-25 and Subsection 2.6.5.4.2.3. Figure 2-25 and Subsection 2.6.5.4.2.3 are applicable to prescriptive-based programs. The intervals may be extended for a performance-based program as provided in Subsection 2.6.11.6.1.2.

2.6.11.6.1.5 Timing for Scheduled Responses (B31.8S - 7.5)

Figure 2-25 contains three plots of the allowed time to respond to an indication, based on the predictive failure pressure P_f divided by the MAOP of the pipeline. The three plots correspond to

(a) pipelines operating at pressures above 50% of SMYS
(b) pipelines operating at pressures above 30% of SMYS but not exceeding 50% of SMYS
(c) pipelines operating at pressures not exceeding 30% of SMYS

The figure is applicable to the prescriptive-based program. The intervals may be extended for the performance-based program as provided in Subsection 2.6.11.6.1.2.

2.6.11.6.1.6 Repair Methods (B31.8S - 7.6)

Figure 2-24 provides acceptable repair methods for each of the 21 threats.

Each operator's integrity management program shall include documented repair procedures. All repairs shall be made with materials and processes that are suitable for the pipeline operating conditions and meet ASME B31.8 requirements.

2.6.11.6.1.7 Prevention Strategy/Methods (B31.8S - 7.7)

Prevention is an important proactive element of an integrity management program. Integrity management program prevention strategies should be based on data gathering, threat identification, and risk assessments conducted per the requirements of Subsections 2.6.5.2.1, 2.6.1.2.1, 2.6.5.4.1, and 2.6.5.6.1. Prevention measures shown to be effective in the past should be continued in the integrity management program. Prevention strategies (including intervals) should also consider the classification of identified threats as time-dependent, stable, or time-independent in order to ensure that effective prevention methods are utilized.

Operators who opt for prescriptive programs should use, at a minimum, the prevention methods indicated in Subsection 2.6.5.4.2 under "Mitigation."

For operators who choose performance-based programs, both the preventive methods and time intervals employed for each threat/segment should be determined by analysis using system attributes, information about existing conditions, and industry-proven risk assessment methods.

2.6.11.6.1.8 Prevention Options (B31.8S - 7.8)

An operator's integrity management program shall include applicable activities to prevent and minimize the consequences of unintended releases. Prevention activities do not necessarily require justification through additional inspection data. Prevention actions can be identified during normal pipeline operation, risk assessment, implementation of the inspection plan, or during repair.

The predominant prevention activities presented in Subsection 2.6.11.6.1 include information on the following:
(a) preventing third-party damage
(b) controlling corrosion
(c) detecting unintended releases
(d) minimizing the consequences of unintended releases
(e) operating pressure reduction

There are other prevention activities that the operator may consider. A tabulation of prevention activities and their relevance to the threats identified in Subsection 2.6.5.2.1 is presented in Figure 2-24.

2.6.11.7 CFR Language: 192.933(d)(1)(i)

(d) Special requirements for scheduling remediation – (1) *Immediate repair conditions* - An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, Section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator

completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(1) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to Part 192.

2.6.11.8 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 7. Section 7 of B31.8S may be found in Subsection 2.6.11.6.1.

2.6.12 CFR Reference: 192.935 What Additional Preventive and Mitigative Measures Must an Operator Take?

2.6.12.1 CFR Language: 192.935(a)

(a) *General requirements* - An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence are. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See 192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

2.6.12.2 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 5. Section 5 of B31.8S may be found in Subsection 2.6.5.6.1.

2.6.12.3 CFR Language: 192.935(b)(1)(iv)

(b) Third party damage and outside force damage –

(1) *Third party damage* - An operator must enhance its damage prevention program, as required under 192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum –

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502-2008 (incorporated by reference, see 192.7). An operator must excavate, and remediate, in accordance with ASME/ANSI B31.8S and 192.933 any indication of coating holidays or discontinuity warranting direct examination.

2.6.12.4 ASME Standard Language

49 CFR 192.935(b)(1)(iv) does not contain direct reference to ASME B31.8S. However, B31.8S Non-Mandatory Appendix A-7 best illustrates the intent of 192.935(b)(1)(iv). Appendix A-7 of B31.8S may be found in Subsection 2.6.5.4.2.7.

2.6.13 CFR Reference: 192.937 What is a Continual Process of Evaluation and Assessment to Maintain a Pipeline's Integrity?

2.6.13.1 CFR Language: 192.937(c)(1)

(c) Assessment methods - In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (see 192.917), or by confirmatory direct assessment under the conditions specified in 192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, see 192.7), Section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

2.6.13.2 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 6.2. Section 6 of B31.8S may be found in Subsection 2.6.5.2.2.

2.6.14 CFR Reference: 192.939 What are the Required Reassessment Intervals?

2.6.14.1 CFR Language: 192.939(a)(1)(i)

(a) Pipelines operating at or above 30% SMYS - An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) Pressure test or internal inspection or other equivalent technology. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by –

(i) Basing the interval on the identified threats for the covered segment (see 192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by 192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S, section 5, Table 3.

2.6.14.2 ASME Standard Language

49 CFR 192.939(a)(1)(i) does not contain direct references to ASME B31.8S. However, B31.8S Section 7 best illustrates the intent of 192.939(a)(1)(i). Section 7 of B31.8S may be found in Subsection 2.6.11.6.1.

2.6.14.3 CFR Language: 192.939(a)(1)(ii)

(a) *Pipelines operating at or above 30% SMYS* - An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.
   (1) *Pressure test or internal inspection or other equivalent technology* - An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by –
      (ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S, Section 5, Table 3.

2.6.14.4 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 5. Section 5 of B31.8S may be found in Subsection 2.6.5.6.1.

2.6.14.5 CFR Language: 192.933(a)(3)

(a) *Pipelines operating at or above 30% SMYS* - An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with 192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.
   (3) *Internal Corrosion or SCC Direct Assessment* - An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, Section 5, Table 3.

2.6.14.6 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 7. Section 7 of B31.8S may be found in Subsection 2.6.11.6.1.

2.6.15 CFR Reference: 192.945 What Methods Must an Operator Use to Measure Program Effectiveness?

2.6.15.1 CFR Language: 192.945(a)

(a) *General* - An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, see 192.7 of this part), Section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by 191.17 of this sub-chapter.

2.6.15.2 ASME Standard Language

The CFR references ASME B31.8S "Supplement to B31.8 on Managing System Integrity of Gas Pipelines" Section 9.4. Section 9.4 of B31.8S may be found in Subsection 2.6.3.2.1.4.

2.7 Appendix

2.7.1 CFR Reference: Item II, Appendix B to Part 192

2.7.1.1 CFR Language: Item II, Appendix B to Part 192

II. Steel pipe of unknown or unlisted specification.

(a) *Bending Properties* - For pipe 2 inches (51 millimeters) or less in diameter, a length of pipe must be cold bent through at least 90 degrees around a cylindrical mandrel that has a diameter 12 times the diameter of the pipe, without developing cracks at any portion and without opening the longitudinal weld.
For pipe more than 2 inches (51 millimeters) in diameter, the pipe must meet the requirements of the flattening tests set forth in ASTM A53 (incorporated by reference, see 192.7), except that the number of tests must be at least equal to the minimum required in paragraph II-D of this appendix to determine yield strength.

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

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

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

NUMBER OF TENSILE TESTS – ALL SIZES

10 lengths or less	1 set of tests for each length.
11 to 100 lengths	1 set of tests for each 5 lengths, but not less than 10 tests
Over 100 lengths	1 set of tests for each 10 lengths, but not less than 20 tests

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

2.7.1.2 ASME Standard Reference:

The CFR references ASME Boiler & Pressure Vessel Code, Section IX, "Welding, Brazing, and Fusing Qualifications" in its entirety.

3 49 CFR 193 – LIQUEFIED NATURAL GAS FACILITIES: FEDERAL SAFETY STANDARDS

3.1 Construction

3.1.1 CFR Reference: 193.2321 Nondestructive Tests

3.1.1.1 CFR Language: 193.2321(a)

(a) The butt welds in metal shells of storage tanks with internal design pressure above 15 psig must be nondestructively examined in accordance with the ASME Boiler and Pressure Vessel Code (Section VIII Division 1)(incorporated by reference, see 193.2013), except that 100 percent of welds that are both longitudinal (or meridional) and circumferential (or latitudinal) of hydraulic load bearing shells with curved surfaces that are subject to cryogenic temperatures must be nondestructively examined in accordance with the ASME Boiler and Pressure Vessel Code (Section VIII Division 1)(Incorporated by reference, see 193.2013).

3.1.1.2 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section VIII, Division I, “Rules for Construction of Pressure Vessels” in its entirety.

4 49 CFR 195 – TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE

4.1 General

4.1.1 CFR Reference: 195.5 Conversion to Service Subject to This Part

4.1.1.1 CFR Language: 195.5(a)(1)(i)

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

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in satisfactory condition for safe operation. If one or more of the variables necessary to verify the design pressure under 195.106 or to perform the testing under paragraph (a)(4) of this section is unknown, the design pressure may be verified and the maximum operating pressure determined by –

(i) Testing the pipeline in accordance with ASME B31.8, Appendix N, to produce a stress equal to the yield strength; and

4.1.1.2 ASME Standard Reference

The CFR references ASME B31.8, "Gas Transmission and Distribution Piping Systems", Appendix N. Appendix N of B31.8 may be found in Subsection 2.5.1.2.1.

4.2 Design Requirements

4.2.1 CFR Reference: 195.118 Fittings

4.2.1.1 CFR Language: 195.118(a)

(a) Butt-welding type fittings must meet the marking, end preparation, and the bursting strength requirements of ASME/ANSI B16.9 or MSS Standard Practice SP-75.

4.2.1.2 ASME Standard Reference

The CFR references ASME B16.9, "Factory-Made Wrought Buttwelding Fittings" in its entirety.

4.2.2 CFR Reference: 195.124 Closures

4.2.2.1 CFR Language: 195.124

Each closure to be installed in a pipeline system must comply with the ASME Boiler and Pressure Vessel Code, Section VIII, Pressure Vessels, Division 1, and must have pressure and temperature ratings at least equal to those of the pipe to which the closure is attached.

4.2.2.2 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section VIII, Division I, Rules for Construction of Pressure Vessels in its entirety.

4.3 Construction

4.3.1 CFR Reference: 195.222 Welders: Qualification of Welders

4.3.1.1 CFR Language: 195.222(a)

(a) Each welder must be qualified in accordance with Section 6 of API 1104 (incorporated by reference, see 195.3) or Section IX of the ASME Boiler and Pressure Code, (incorporated by reference, see 195.3) except that a welder qualified under an earlier edition than listed in 195.3 may weld but may not re-qualify under that earlier edition.

4.3.1.2 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section IX, "Welding, Brazing, and Fusing Qualifications" in its entirety.

4.4 Pressure Testing

4.4.1 CFR Reference: 195.307 Pressure Testing Aboveground Breakout Tanks

4.4.1.1 CFR Language: 195.307(e)

(e) For aboveground breakout tanks built to API Standard 2510 and first placed in service after October 2, 2000, pressure testing must be in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2.

4.4.1.2 ASME Standard Reference

The CFR references ASME Boiler & Pressure Vessel Code, Section VIII, Division I, Rules for Construction of Pressure Vessels in its entirety.

4.5 Operation and Maintenance

4.5.1 CFR Reference: 195.406 Maximum Operating Pressure

4.5.1.1 CFR Language: 195.406(a)(1)(i)

(a) Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:
- *(1)* The internal design pressure of the pipe determined in accordance with 195.106. However, for steel pipe in pipelines being converted under 195.5, if one or more factors of the design formula (195.106) are 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 N5.0 of appendix N of ASME B31.8, reduced by the appropriate factors in 195.106(a) and (e); or
  - (ii) If the pipe is 12 ¾ inch (324 mm) or less outside diameter and is not tested to yield under this paragraph, 200 psi (1379 kPa) gage.

4.5.1.2 ASME Standard Reference

The CFR references ASME B31.8, Gas Transmission and Distribution Piping Systems, Section N5.0 of Appendix N in its entirety. Appendix N of B31.8 may be found in Subsection 2.5.1.2.1.

4.5.2 CFR Reference: 195.452 Pipeline Integrity Management in High Consequence Areas

4.5.2.1 CFR Language: 195.452(h)(4)(i), 195.452(h)(4)(i)(B)

(h) What actions must an operator take to address integrity issues: -

(4) Special requirements for scheduling remediation –

(i) Immediate repair conditions - An operator's evaluation and remediation schedule must provide for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure or shut down the pipeline until the operator completes the repair of these conditions. An operator must calculate the temporary reduction in operating pressure using the formula in Section 451.6.2.2(b) of ANSI/ASME B31.4 (incorporated by reference, see 195.3). An operator must treat the following conditions as immediate repair conditions:

(B) A calculation of the remaining strength of the pipe shows a predicted burst pressure less than the established maximum operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G ("Manual for Determining the Remaining Strength of Corroded Pipelines" (1991) or AGA Pipeline Research Committee Project PR-3-805 ("A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe" (December 1989)). These documents are incorporated by reference and are available at the addresses listed in 195.3.

4.5.2.2 ASME Standard Reference

The CFR references ASME B31.4, "Pipeline Transportation Systems for Liquids and Slurries", Section 451.6.2.2(b). For user convenience, Section 451.6.2 of B31.4 has been included below.

4.5.2.2.1 Limits and Disposition of Imperfections and Anomalies (B31.4 – 451.6.2)

4.5.2.2.1.1 Limits (B31.4 – 451.6.2.1)

Pipe containing leaks shall be removed or repaired.

4.5.2.2.1.2 Corrosion (B31.4 – 451.6.2.2)

(a) External or Internal Corrosion. Areas of external or internal metal loss with a maximum depth greater than 80% of the wall thickness shall be removed or repaired. An appropriate fitness-for-purpose criterion may be used to evaluate the longitudinal profile of corrosion caused metal loss in base metal of the pipe or of non-preferential corrosion-caused metal loss which crosses a girth weld or impinges on a submerged arc welded seam.

(b) External Corrosion. Externally corroded areas exposed for examination must be cleaned to bare metal. In general, areas of corrosion with a maximum depth of 20% or less of the thickness required for design (t) need not be repaired. However, measures should be taken to prevent further corrosion. An area of corrosion with maximum depth greater than 20% but less than or equal to 80% of the wall thickness shall be permitted to remain in the pipeline unrepaired provided that the pressure at such an area does not exceed a safe level. Generally acceptable methods for calculating a safe operating pressure include: ASME B31G, "modified B31G," an effective area method (e.g., RSTRENG).

For pipelines subjected to unusual axial loads, lateral movement or settlement, or for pipelines comprised of materials with yield-to-tensile ratios exceeding 0.93, an engineering critical assessment shall be performed to calculate a safe pressure.

If the safe operating pressure is less than the intended operating pressure, the affected area shall be removed or repaired.

(c) Internal Corrosion. The limitations for areas with internal corrosion and areas with a combination of internal and external corrosion are the same as for external corrosion. When dealing with internal

corrosion, consideration should be given to the uncertainty related to the indirect measurement of wall thickness and the possibility that internal corrosion may require continuing mitigative efforts to prevent additional metal loss.

(d) Interaction of Corrosion-Caused Metal Loss Areas. Two or more areas of corrosion-caused metal loss that are separated by areas of full wall thickness may interact in a manner that reduces the remaining strength to a greater extent than the reduction resulting from the individual areas. Two types of interaction are possible and each should be assessed as follows:

(1) Type I Interaction (see Figure 4-1). If the circumferential separation distance, C, is greater than or equal to 6 times the wall thickness required for design, the areas A1 and A2 should be evaluated as separate anomalies. If the circumferential separation distance is less than six times the wall thickness, the composite area (A1 + A2 − A3) and the overall length, L, should be used.

(2) Type II Interaction (see Figure 4-2). If the axial separation distance, L3, is greater than or equal to 1 in. (25.4 mm), the areas A1 and A2 should be evaluated as separate anomalies. If the axial separation distance is less than 1 in. (25.4 mm), area A1 plus A2 should be used and the length, L, should be taken as L1 + L2 + L3.

(e) Grooving, Selective, or Preferential Corrosion of Welds. Grooving, selective, or preferential corrosion of the longitudinal seam of any pipe manufactured by the electric resistance welding (ERW) process, electric induction welding process, or electric flash welding process shall be removed

Figure 4-1: Type I Interaction (B31.4 - Fig. 451.6.2.2-1)

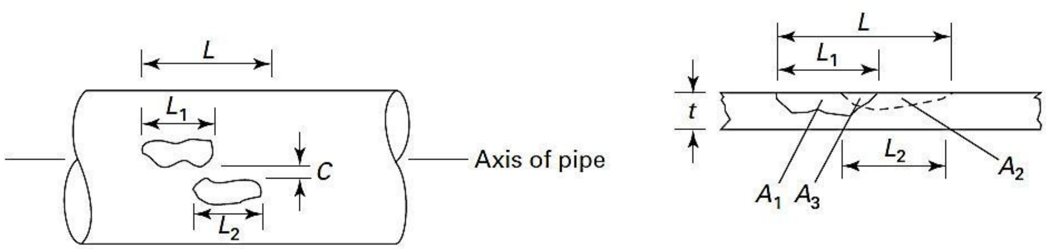
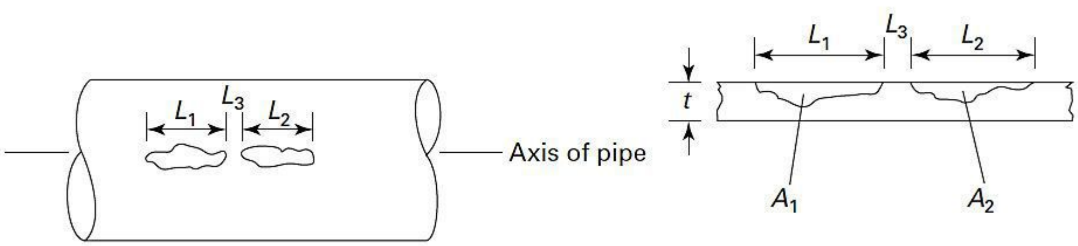


Figure 4-2: Type 2 Interaction (B31.4 - Fig. 451.6.2.2-2)



4.5.2.3 CFR Language: 195.452(h)(4)(iii)(D)

(h) What actions must an operator take to address integrity issues: -

(4) Special requirements for scheduling remediation –

(iii) 180-day conditions - Except for conditions listed in paragraph (h)(4)(i) or (ii) of this section, an operator must schedule evaluation and remediation of the following within 180 days of discovery of the condition:

(D) calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly.

Suitable remaining strength calculation methods include, but are not limited to, ASME/ANSI B31G (“Manual for Determining the Remaining Strength of Corroded Pipelines” (1991)) or AGA Pipeline Research Committee Project PR-3-805 (“A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe” (December 1989)). These documents are incorporated by reference and are available at the addresses listed in 195.3.

4.5.2.4 ASME Standard Reference

The CFR references ASME B31G, “Manual for Determining the Remaining Strength of Corroded Pipelines” in its entirety.

APPENDIX A – DESCRIPTIONS OF REFERENCED ASME STANDARDS

This Appendix is provided for informational purposes only. The following descriptions are taken primarily from the scopes of the respective documents. They have been edited for clarity and consistency. For practical applications, the scope of the governing standard applies.

B16.1 Gray Iron Pipe Flanges and Flanged Fittings: (Classes 25, 125, and 250)

This Standard covers Classes 25, 125, and 250 Gray Iron Pipe Flanges and Flanged Fittings. It includes:
(a) pressure–temperature ratings
(b) sizes and method of designating openings of reducing fittings
(c) marking
(d) materials
(e) dimensions and tolerances
(f) bolting and gaskets
(g) pressure testing

B16.5 Pipe Flanges and Flanged Fittings

This Standard covers pressure-temperature ratings, materials, dimensions, tolerances, marking, testing, and methods of designating openings for pipe flanges and flanged fittings including:
(a) flanges with rating class designations 150, 300, 400, 600, 900, and 1500 in sizes NPS 1⁄2 through NPS 24 and flanges with rating class designation 2500 in sizes NPS 1⁄2 through NPS 12, with requirements given in both metric and U.S. Customary units with diameter of bolts and flange bolt holes expressed in inch units;
(b) flanged fittings with rating class designation 150 and 300 in sizes NPS 1⁄2 through NPS 24; and
(c) flanged fittings with rating class designation 400, 600, 900, and 1500 in sizes NPS 1⁄2 through NPS 24 and flanged fittings with rating class designation 2500 in sizes NPS 1⁄2 through NPS 12

This Standard is limited to:
(a) flanges and flanged fittings made from cast or forged materials
(b) blind flanges and certain reducing flanges made from cast, forged, or plate materials
(c) requirements and recommendations regarding flange bolting, gaskets, and joints.

B16.9 Factory-Made Wrought Buttwelding Fittings

This Standard covers overall dimensions, tolerances, ratings, testing, and markings for factory-made wrought butt welding fittings in size NPS 1⁄2 through NPS 48 (DN 15 through DN 1200). Fittings may be made to special dimensions, sizes, shapes, and tolerances by agreement between the manufacturer and the purchaser. Fabricated laterals and other fittings employing circumferential or intersection welds are considered pipe fabrication and are not within the description of this Standard. Fabricated lap joint stub ends are exempt from the above restrictions, provided they meet all the requirements of the applicable ASTM material specification listed in this Standard.

B31G Manual for Determining the Remaining Strength of Corroded Pipelines.

This document is intended solely for the purpose of providing guidance in the evaluation of metal loss in pressurized pipelines and piping systems. It is applicable to all pipelines and piping systems within the description of the transportation pipeline codes that are part of ASME B31 Code for Pressure Piping, namely: ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids; ASME B31.8, Gas Transmission and Distribution Piping Systems; ASME B31.11, Slurry Transportation Piping Systems; and ASME B31.12, Hydrogen Piping and Pipelines, Part PL. Where the term pipeline is used, it may also be read to apply to piping or pipe conforming to the acceptable applications and within technical limitations.

B31.4 Pipeline Transportation Systems for Liquids and Slurries

This Code prescribes requirements for the design, materials, construction, assembly, inspection, testing, operation, and maintenance of piping transporting liquids between production facilities, tank farms, natural gas processing plants, refineries, pump stations, ammonia plants, terminals (marine, rail, and truck), and other delivery and receiving points. This Code also prescribes requirements for the design, materials, construction, assembly, inspection, testing, operation, and maintenance of piping transporting aqueous slurries of nonhazardous materials such as coal, mineral ores, concentrates, and other solid materials, between a slurry processing plant or terminal and a receiving plant or terminal. Piping consists of pipe, flanges, bolting, gaskets, valves, relief devices, fittings, and the pressure containing parts of other piping components. It also includes hangers and supports, and other equipment items necessary to prevent overstressing the pressure containing parts. It does not include support structures such as frames of buildings, stanchions, or foundations. Also included within the description of this Code are:

(a) primary and associated auxiliary liquid petroleum and liquid anhydrous ammonia piping at pipeline terminals (marine, rail, and truck), tank farms, pump stations, pressure reducing stations, and metering stations, including scraper traps, strainers, and prover loops;
(b) storage and working tanks, including pipe-type storage fabricated from pipe and fittings, and piping interconnecting these facilities;
(c) liquid petroleum and liquid anhydrous ammonia piping located on property that has been set aside for such piping within petroleum refinery, natural gasoline, gas processing, ammonia, and bulk plants; and
(d) those aspects of operation and maintenance of liquid pipeline systems relating to the safety and protection of the general public, operating company personnel, environment, property, and the piping systems.

B31.8 Gas Transmission and Distribution Piping Systems

(a) This Code covers the design, fabrication, installation, inspection, and testing of pipeline facilities used for the transportation of gas. This Code also covers safety aspects of the operation and maintenance of those facilities. This Code is concerned only with certain safety aspects of liquefied petroleum gases when they are vaporized and used as gaseous fuels. All of the requirements of NFPA 58 and NFPA 59 and of this Code concerning design, construction, and operation and maintenance of piping facilities shall apply to piping systems handling butane, propane, or mixtures of these gases.
(b) This Code does not apply to:
  (1) design and manufacture of pressure vessels covered by the BPV Code
  (2) piping with metal temperatures above 450°F (232°C) or below −20°F (−29°C)
  (3) piping beyond the outlet of the customer's meter set assembly (Refer to ANSI Z223.1/NFPA 54.)
  (4) piping in oil refineries or natural gasoline extraction plants, gas treating plant piping other than the main gas stream piping in dehydration, and all other processing plants installed as part of a gas transmission system, gas manufacturing plants, industrial plants, or mines
  (5) vent piping to operate at substantially atmospheric pressures for waste gases of any kind
  (6) wellhead assemblies, including control valves, flow lines between wellhead and trap or separator, offshore platform production facility piping, or casing and tubing in gas or oil wells (For offshore platform production facility piping, see API RP 14E.)
  (7) the design and manufacture of proprietary items of equipment, apparatus, or instruments
  (8) the design and manufacture of heat exchangers (Refer to appropriate TEMA2 Standard.)
  (9) liquid petroleum transportation piping systems (Refer to ASME B31.4.)
  (10) liquid slurry transportation piping systems
  (11) carbon dioxide transportation piping systems

(12) liquefied natural gas piping systems (Refer to NFPA 59A and ASME B31.3.)(13) cryogenic piping systems

B31.8S Supplement to B31.8 on Managing System Integrity of Gas Pipelines.

This Code applies to onshore pipeline systems constructed with ferrous materials and that transport gas. The principles and processes embodied in integrity management are applicable to all pipeline systems. This Code is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes. The processes and approaches within this Code are applicable to the entire pipeline system.

BPVC Boiler & Pressure Vessel Code, Section I, Rules for Construction of Power Boilers

The Boiler and Pressure Vessel Standards Committees' function is to establish rules of safety relating only to pressure integrity, which govern the construction of boilers, pressure vessels, transport tanks, and nuclear components, and the in-service inspection of nuclear components and transport tanks. This Code covers rules for construction of power boilers, electric boilers, miniature boilers, high-temperature water boilers, heat recovery steam generators, and certain fired pressure vessels to be used in stationary service and includes those power boilers used in locomotive, portable, and traction service. The description of Section I applies to the boiler proper and to the boiler external piping. Superheaters, economizers, and other pressure parts connected directly to the boiler without intervening valves are considered as parts of the boiler proper, and their construction shall conform to Section I rules. Boiler external piping is considered as that piping which begins where the boiler proper or isolable superheater or isolable economizer terminates at:

(a) the first circumferential joint for welding end connections; or
(b) the face of the first flange in bolted flanged connections; or
(c) the first threaded joint in that type of connection; and which extends up to and including the valve or valves required by this Code.

ASME Code Certification and/or inspection by the Authorized Inspector, when required by this Code, is required for the boiler proper and the boiler external piping. Construction rules for materials, design, fabrication, installation, and testing of the boiler external piping are contained in the ASME B31.1 Power Piping Code. Piping beyond the valve or valves required by Section I is not within the description of Section I, and it is not the intent that the Certification Mark be applied to such piping or any other piping. The material for forced-circulation boilers, boilers with no fixed steam and water line, and high-temperature water boilers shall conform to the requirements of the Code. Reheaters receiving steam which has passed through part of a turbine or other prime mover and separately fired steam superheaters which are not integral with the boiler are considered fired pressure vessels and their construction shall comply with Code requirements for superheaters, including safety devices. Piping between the reheater connections and the turbine or other prime mover is not within the description of the Code. Steam piping to the inlet connections and from the outlet connections of nonintegral separately fired superheaters is not within the description of this Code.

A pressure vessel in which steam is generated by the application of heat resulting from the combustion of fuel (solid, liquid, or gaseous) shall be classed as a fired steam boiler. Unfired pressure vessels in which steam is generated shall be classed as unfired steam boilers with the following exceptions:

(a) vessels known as evaporators or heat exchangers
(b) vessels in which steam is generated by the use of heat resulting from operation of a processing system containing a number of pressure vessels such as used in the manufacture of chemical and petroleum products

Unfired steam boilers shall be constructed under the provisions of Section I or Section VIII. Expansion tanks connected to high-temperature water boilers without intervening valves shall be constructed to the requirements of Section I or Section VIII. A pressure vessel in which an organic fluid is vaporized by the application of heat resulting from the combustion of fuel (solid, liquid, or gaseous) shall be constructed under the provisions of Section I. Vessels in which vapor is generated incidental to the operation of a processing system, containing a number of pressure vessels such as used in chemical and petroleum manufacture, are not covered by the rules of Section I.

BPVC Boiler & Pressure Vessel Code, Section VIII, Division 1, Rules for Construction of Pressure Vessels

(a) The Boiler and Pressure Vessel Standards Committees' function is to establish rules of safety relating only to pressure integrity, which govern the construction of boilers, pressure vessels, transport tanks, and nuclear components, and the inservice inspection of nuclear components and transport tanks. For the description of this Division, pressure vessels are containers for the containment of pressure, either internal or external. This pressure may be obtained from an external source, or by the application of heat from a direct or indirect source, or any combination thereof.

(b) The following classes of vessels are not included in the description of this Division:
- (1) those within the description of other Sections;
- (2) fired process tubular heaters;
- (3) pressure containers which are integral parts or components of rotating or reciprocating mechanical devices, such as pumps, compressors, turbines, generators, engines, and hydraulic or pneumatic cylinders where the primary design considerations and/or stresses are derived from the functional requirements of the device;
- (4) structures whose primary function is the transport of fluids from one location to another within a system of which it is an integral part, that is, piping systems;
- (5) piping components, such as pipe, flanges, bolting, gaskets, valves, expansion joints, fittings, and the pressure containing parts of other components, such as strainers and devices which serve such purposes as mixing, separating, snubbing, distributing, and metering or controlling flow, provided that pressure containing parts of such components are generally recognized as piping components or accessories;
- (6) a vessel for containing water under pressure, including those containing air the compression of which serves only as a cushion, when none of the following limitations are exceeded:
  - (i) a design pressure of 300 psi (2 MPa);
  - (ii) a design temperature of 210°F (99°C);
- (7) a hot water supply storage tank heated by steam or any other indirect means when none of the following limitations is exceeded:
  - (i) a heat input of 200,000 Btu/hr (58.6 kW);
  - (ii) a water temperature of 210°F (99°C);
  - (iii) a nominal water containing capacity of 120 gal (450 L);
- (8) vessels not exceeding the design pressure, at the top of the vessel, limitations below, with no limitation on size:
  - (i) vessels having an internal or external pressure not exceeding 15 psi (100 kPa);
  - (ii) combination units having an internal or external pressure in each chamber not exceeding 15 psi (100 kPa) and differential pressure on the common elements not exceeding 15 psi (100 kPa);
  - (iv) vessels having an inside diameter, width, height, or cross section diagonal not exceeding 6 in. (152 mm), with no limitation on length of vessel or pressure;
  - *(iv)* pressure vessels for human occupancy.

(c) Any pressure vessel which meets all the applicable requirements of this Division may be stamped with the Certification Mark with the U Designator.

(d) The rules of this Division have been formulated on the basis of design principles and construction practices applicable to vessels designed for pressures not exceeding 3,000 psi (20 MPa). For pressures above 3,000 psi (20 MPa), deviations from and additions to these rules usually are necessary to meet the requirements of design principles and construction practices for these higher pressures.

(e) In relation to the geometry of pressure containing parts, the description of this Division includes the following:
- (1) where external piping; other pressure vessels including heat exchangers; or mechanical devices, such as pumps, mixers, or compressors, are to be connected to the vessel:
  - (i) the welding end connection for the first circumferential joint for welded connections
  - (ii) the first threaded joint for screwed connections;
  - (iii) the face of the first flange for bolted, flanged connections;
  - (iv) the first sealing surface for proprietary connections or fittings;
- (2) where nonpressure parts are welded directly to either the internal or external pressure retaining surface of a pressure vessel, this description shall include the design, fabrication, testing, and material requirements established for nonpressure part attachments by the applicable paragraphs of this Division;
- (3) pressure retaining covers for vessel openings, such as manhole or handhole covers, and bolted covers with their attaching bolting and nuts;
- (4) the first sealing surface for proprietary fittings or components for which rules are not provided by this Division, such as gages, instruments, and nonmetallic components.

(f) The description of this Division includes provisions for pressure relief devices necessary to satisfy the requirements of this Division.

(g) Unfired steam boilers shall be constructed in accordance with the rules of Section I or this Division. The following pressure vessels in which steam is generated shall not be considered as unfired steam boilers, and shall be constructed in accordance with the rules of this Division:
- (1) vessels known as evaporators or heat exchangers;
- (2) vessels in which steam is generated by the use of heat resulting from operation of a processing system containing a number of pressure vessels such as used in the manufacture of chemical and petroleum products;
- (3) vessels in which steam is generated but not withdrawn for external use.

(h) Pressure vessels or parts subject to direct firing from the combustion of fuel (solid, liquid, or gaseous), which are not within the description of Sections I, III, or IV may be constructed in accordance with the rules of this Division.

(i) Gas fired jacketed steam kettles with jacket operating pressures not exceeding 50 psi (345 kPa) may be constructed in accordance with the rules of this Division.

(j) Pressure vessels exclusive of those covered in (b), (g), (h), and (i) that are not required by the rules of this Division to be fully radiographed, which are not provided with quick actuating closures, and that do not exceed the following volume and pressure limits, may be exempted from inspection by Inspectors as defined in this Division, provided that they comply in all other respects with the requirements of this Division:
- (1) 5 ft3 (0.14 m3) in volume and 250 psi (1.7 MPa) design pressure; or
- (2) 3 ft3 (0.08 m3) in volume and 350 psi (2.4 MPa) design pressure;
- (3) 1-1/2 ft3 (0.04 m3) in volume and 600 psi (4.1 MPa) design pressure.

BPVC Boiler & Pressure Vessel Code, Section VIII, Division 2, Alternative Rules, Rules for Construction of Pressure Vessels

(a) The Boiler and Pressure Vessel Standards Committees' function is to establish rules of safety relating only to pressure integrity, which govern the construction of boilers, pressure vessels, transport tanks, and nuclear components, and the inservice inspection of nuclear components and transport tanks. For the description of this Division, pressure vessels are containers for the containment of pressure, either internal or external. This pressure may be obtained from an external source, or by the application of heat from a direct or indirect source, or any combination thereof.

(b) The rules of this Division may be used for the construction of the following pressure vessels.
- (1) Vessels to be installed at a fixed (stationary) location for a specific service where operation and maintenance control is retained during the useful life of the vessel by the user and is in conformance with the User's Design Specification.
- (2) Pressure vessels installed in ocean-going ships, barges, and other floating craft or used for motor vehicle or rail freight. Such pressure vessels may be constructed and stamped per the requirements of this Division.

(c) Pressure vessels or parts subject to direct firing from the combustion of fuel (solid, liquid, or gaseous), that are not within the description of Sections I, III, or IV may be constructed in accordance with the rules of this Division.

(d) Unfired steam boilers shall be constructed in accordance with the rules of Section I or Section VIII, Division 1.

(e) The following pressure vessels in which steam is generated shall be constructed in accordance with the rules of Section VIII, Division 1 or this Division:
- (1) Vessels known as evaporators or heat exchangers;
- (2) Vessels in which steam is generated by the use of heat resulting from operation of a processing system containing a number of pressure vessels such as used in the manufacture of chemical and petroleum products; and
- (3) Vessels in which steam is generated but not withdrawn for external use.

(f) The rules of this Division do not specify a limitation on pressure but are not all-inclusive for all types of construction. For very high pressure vessels, some additions to these rules may be necessary to meet the design principles and construction practices essential to vessels for such pressures.

(g) As an alternative to this Division, Section VIII, Division 3 may be considered for the construction of vessels intended for operating pressures exceeding 68.95 MPa (10,000 psi).

(h) Geometric Description of this Division
The description of this Division is intended to include only the vessel and integral communicating chambers, and shall include the following:
- (1) Where external piping, other pressure vessels including heat exchangers, or mechanical devices (i.e. pumps, mixers, or compressors) are to be connected to the vessel:
  - (i) The welding end connection for the first circumferential joint for welded connections.
  - (ii) The first threaded joint for screwed connections.
  - (iii) The face of the first flange for bolted and flanged connections. Optionally, when the first flange is welded to the nozzle neck, the weld connecting the flange to the nozzle neck may be considered as the first circumferential joint, provided this construction is documented in the

User's Design Specification and is properly described on the vessel drawing and the Manufacturer's Data Report.

(iv) The first sealing surface for proprietary connections or fittings.

(2) Where nonpressure parts are welded directly to either the internal or external pressure retaining surface of a pressure vessel, the description of this Division includes the design, fabrication, testing, and material requirements established for nonpressure part attachments by the applicable paragraphs of this Division.

(3) Pressure retaining covers and their fasteners (bolts and nuts) for vessel openings, such as manhole and handhole covers.

(4) The first sealing surface for proprietary connections, fittings or components that are designed to rules that are not provided by this Division, such as gages, instruments, and nonmetallic components.

(i) Classifications outside the Description of this Division

The following vessels are not included in the description of this Division.

(1) Vessels within the description of other Sections.

(2) Fired process tubular heaters as defined in API RP560.

(3) Pressure containers that are integral parts or components of rotating or reciprocating mechanical devices, such as pumps, compressors, turbines, generators, engines, and hydraulic or pneumatic cylinders where the primary design considerations and/or stresses are derived from the functional requirements of the device.

(4) Structures consisting of piping components, such as pipe, flanges, bolting, gaskets, valves, expansion joints, and fittings whose primary function is the transport of fluids from one location to another within a system of which it is an integral part, that is, piping systems, including the piping system between a pressure relief device and the vessel it protects.

(5) Pressure containing parts of components, such as strainers and devices that serve such purposes as mixing, separating, snubbing, distributing, and metering or controlling flow, provided that pressure containing parts of such components are generally recognized as piping components or accessories.

(6) A vessel for containing water under pressure, including those containing air the compression of which serves only as a cushion, when none of the following limitations are exceeded:

(i) A design pressure of 2.07 MPa (300 psi)

(ii) A design temperature of 99°C (210°F)

(7) A hot water supply storage tank heated by steam or any other indirect means when none of the following limitations is exceeded:

(i) A heat input of 58.6 kW (200,000 Btu/hr)

(ii) A water temperature of 99°C (210°F)

(iii) A nominal water-containing capacity of 454 L (120 gal)

(8) Vessels with an internal or external design pressure not exceeding 103 kPa (15 psi) with no limitation on size, for multi-chambered vessels, the design pressure on the common elements shall not exceed 103 kPa (15 psi).

(9) Vessels with an inside diameter, width, height, or cross section diagonal not exceeding 150 mm (6 in.), with no limitation on length of vessel or pressure.

(10) Pressure vessels for human occupancy (requirements for pressure vessels for human occupancy are covered in ASME PVHO-1.

(j) Combination Units

When a pressure vessel unit consists of more than one independent pressure chamber, only the chambers that come within the description of this Division need be constructed in compliance with its provisions.

(k) Pressure Relief Devices
The description of this Division includes provisions for pressure relief devices necessary to satisfy the requirements of this Division.

BPVC Boiler & Pressure Vessel Code, Section IX, Welding, Brazing, and Fusing Qualifications

This Section contains requirements for the qualification of welders, welding operators, brazers, brazing operators, plastic fusing machine operators, and the material joining processes they use during welding, brazing, and fusing operations for the construction of components under the rules of the ASME Boiler and Pressure Vessel Code, the ASME B31 Codes for Pressure Piping, and other Codes, standards, and specifications that reference this Section. This Section is divided into four parts:
(a) Part QG contains general requirements for all material-joining processes.
(b) Part QW contains requirements for welding.
(c) Part QB contains requirements for brazing.
(d) Part QF contains requirements for plastic fusing.

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