Managing System Integrity of Gas Pipelines

ASME Code for Pressure Piping, B31
Supplement to ASME B31.8

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

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ASME B31.8S-2012

(Revision of ASME B31.8S-2010)

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Three Park Avenue • New York, NY • 10016 USA

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The next edition of this Code is scheduled for publication in 2014.

ASME issues written replies to inquiries concerning interpretations of technical aspects of this Code. Periodically certain actions of the ASME B31 Committee may be published as Cases. Cases and interpretations are published on the ASME Web site under the Committee Pages at http://cstools.asme.org/ as they are issued.

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CONTENTS

Nonmandatory Appendices

FOREWORD

Pipeline system operators continuously work to improve the safety of their systems and operations. In the United States, both liquid and gas pipeline operators have been working with their regulators for several years to develop a more systematic approach to pipeline safety integrity management.

The gas pipeline industry needed to address many technical concerns before an integrity management standard could be written. A number of initiatives were undertaken by the industry to answer these questions; as a result of 2 yr of intensive work by a number of technical experts in their fields, 20 reports were issued that provided the responses required to complete the 2002 edition of this Code. (The list of these reports is included in the reference section of this Code.)

This Code is nonmandatory, and is designed to supplement B31.8, ASME Code for Pressure Piping, Gas Transmission and Distribution Piping Systems. Not all operators or countries will decide to implement this Code. This Code becomes mandatory if and when pipeline regulators include it as a requirement in their regulations.

This Code is a process code, which describes the process an operator may use to develop an integrity management program. It also provides two approaches for developing an integrity management program: a prescriptive approach and a performance or risk-based approach. Pipeline operators in a number of countries are currently utilizing risk-based or risk-management principles to improve the safety of their systems. Some of the international standards issued on this subject were utilized as resources for writing this Code. Particular recognition is given to API and their liquids integrity management standard, API 1160, which was used as a model for the format of this Code.

The intent of this Code is to provide a systematic, comprehensive, and integrated approach to managing the safety and integrity of pipeline systems. The task force that developed this Code hopes that it has achieved that intent.

The 2004 Supplement was approved by the B31 Standards Committee and by the ASME Board on Pressure Technology Codes and Standards. It was approved as an American National Standard on March 17, 2004.

The 2010 Supplement was approved by the B31 Standards Committee and by the ASME Board on Pressure Technology Codes and Standards. It was approved as an American National Standard on April 20, 2010.

The 2012 Edition of the Supplement is a compilation of the 2010 Edition and the revisions that occurred since the issuance of the 2010 Edition. This Edition was approved by ANSI on September 14, 2012.

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Code for Pressure Piping

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ASME B31.8S-2012
SUMMARY OF CHANGES

Following approval by the ASME B31 Standards Committee, the ASME Board on Pressure Technology Codes and Standards, and ASME, and after public review, ASME B31.8S-2012 was approved by the American National Standards Institute on September 14, 2012.

ASME B31.8S-2012 consists of B31.8S-2010; editorial changes, revisions, and corrections; as well as the following changes identified by a margin note, **(12)**.

Page	*Location*	*Change*
14	Table 5.6.1-1	(1) All entries for Direct assessment revised (2) Note (4) revised
20	6.4.1	First and last paragraph revised
23, 24	Table 7.1-1	General Note, definition for *ECA* revised
28	9.1	First paragraph revised
31–33	9.4(b)(1)	Revised
	9.4(b)(2)	Revised
	9.4(b)(3)	Revised
	9.4(c)	Revised
	Table 9.4(b)-1	Revised
	Table 9.4(c)-1	Revised
	9.4(e)(8)	Revised
	9.4(e)(9)	Revised
35–43	12.2(b)	Revised
	12.2(b)(1)	Revised
	12.2(b)(6)	Revised
	13	(1) Definitions of *butt joint, butt weld, discontinuity, engineering assessment,* and *in-line inspection tools* added (2) Definitions of *engineering critical assessment* and *smart pig* revised
	14	Revised
50	A-3.1	Revised
	A-3.2	First paragraph revised
	A-3.3	Title revised
	A-3.3.1	First paragraph revised
	A-3.3.2	(1) First paragraph revised (2) Fourth paragraph of A-3.3.2 redesignated as A-3.3.3 and revised (3) Last paragraph revised

Page	*Location*	*Change*
	A-3.4	(1) Second and third paragraphs revised (2) Fourth paragraph added
51	Fig. A-3	Deleted
	A-3.4.1	(1) Second and third paragraphs deleted (2) Last paragraph revised
	A-3.4.2(d)(1)(b)	Revised
	A-3.4.2(d)(3)	Deleted
	A-3.4.3	Revised
	A-3.4.4	Added
52	Table A-3.4.1-1	Title revised
	A-3.5	Revised
	A-3.6(b)	Revised
54	A-4.3	(1) First paragraph revised (2) Third paragraph added
65	B-1	Revised in its entirety
	Table B-1	Deleted
	B-2	Revised

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MANAGING SYSTEM INTEGRITY OF GAS PIPELINES

1 INTRODUCTION

1.1 Scope

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 (as defined in section 13) 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.

1.2 Purpose and Objectives

Managing the integrity of a gas pipeline system is the primary goal of every pipeline system operator. Operators want to continue providing safe and reliable delivery of natural gas to their customers without adverse effects on employees, the public, customers, or the environment. Incident-free operation has been and continues to be the gas pipeline industry's goal. The use of this Code as a supplement to the ASME B31.8 Code will allow pipeline operators to move closer to that goal.

A comprehensive, systematic, and integrated integrity management program provides the means to improve the safety of pipeline systems. Such an integrity management program provides the information for an operator to effectively allocate resources for appropriate prevention, detection, and mitigation activities that will result in improved safety and a reduction in the number of incidents.

This Code describes a process that an operator of a pipeline system can use to assess and mitigate risks in order to reduce both the likelihood and consequences of incidents. It covers both a prescriptive- and a performance-based integrity management program.

The prescriptive process, when followed explicitly, will provide all the inspection, prevention, detection, and mitigation activities necessary to produce a satisfactory integrity management program. This does not preclude conformance with the requirements of ASME B31.8. The performance-based integrity management program alternative utilizes more data and more extensive risk analyses, which enables the operator to achieve a greater degree of flexibility in order to meet or exceed the requirements of this Code specifically in the areas of inspection intervals, tools used, and mitigation techniques employed. An operator cannot proceed with the performance-based integrity program until adequate inspections are performed that provide the information on the pipeline condition required by the prescriptive-based program. The level of assurance of a performance-based program or an alternative international standard must meet or exceed that of a prescriptive program.

The requirements for prescriptive- and performance-based integrity management programs are provided in each of the sections in this Code. In addition, Nonmandatory Appendix A provides specific activities, by threat categories, that an operator shall follow in order to produce a satisfactory prescriptive integrity management program.

This Code is intended for use by individuals and teams charged with planning, implementing, and improving a pipeline integrity management program. Typically, a team will include managers, engineers, operating personnel, technicians, and/or specialists with specific expertise in prevention, detection, and mitigation activities.

1.3 Integrity Management Principles

A set of principles is the basis for the intent and specific details of this Code. They are enumerated here so that the user of this Code can understand the breadth and depth to which integrity shall be an integral and continuing part of the safe operation of a pipeline system.

Functional requirements for integrity management shall be engineered into new pipeline systems from initial planning, design, material selection, and construction. Integrity management of a pipeline starts with sound design, material selection, and construction of the pipeline. Guidance for these activities is primarily provided in ASME B31.8. There are also a number of consensus standards that may be used, as well as pipeline jurisdictional safety regulations. If a new line is to become a part of an integrity management program, the functional requirements for the line, including prevention, detection, and mitigation activities, shall be considered in order to meet this Code. Complete records of material, design, and construction for the pipeline are essential for the initiation of a good integrity management program.

System integrity requires commitment by all operating personnel using comprehensive, systematic, and integrated processes to safely operate and maintain pipeline systems. In order to have an effective integrity management program, the program shall address the operator's organization, processes, and the physical system.

An integrity management program is continuously evolving and must be flexible. An integrity management program should be customized to meet each operator's unique conditions. The program shall be periodically evaluated and modified to accommodate changes in pipeline operation, changes in the operating environment, and the influx of new data and information about the system. Periodic evaluation is required to ensure the program takes appropriate advantage of improved technologies and that the program utilizes the best set of prevention, detection, and mitigation activities that are available for the conditions at that time. Additionally, as the integrity management program is implemented, the effectiveness of the activities shall be reassessed and modified to ensure the continuing effectiveness of the program and all its activities.

Information integration is a key component for managing system integrity. A key element of the integrity management framework is the integration of all pertinent information when performing risk assessments. Information that can impact an operator's understanding of the important risks to a pipeline system comes from a variety of sources. The operator is in the best position to gather and analyze this information. By analyzing all of the pertinent information, the operator can determine where the risks of an incident are the greatest, and make prudent decisions to assess and reduce those risks.

Risk assessment is an analytical process by which an operator determines the types of adverse events or conditions that might impact pipeline integrity. Risk assessment also determines the likelihood or probability of those events or conditions that will lead to a loss of integrity, and the nature and severity of the consequences that might occur following a failure. This analytical process involves the integration of design, construction, operating, maintenance, testing, inspection, and other information about a pipeline system. Risk assessments, which are the very foundation of an integrity management program, can vary in scope or complexity and use different methods or techniques. The ultimate goal of assessing risks is to identify the most significant risks so that an operator can develop an effective and prioritized prevention/detection/mitigation plan to address the risks.

Assessing risks to pipeline integrity is a continuous process. The operator shall periodically gather new or additional information and system operating experience. These shall become part of revised risk assessments and analyses that in turn may require adjustments to the system integrity plan.

New technology should be evaluated and implemented as appropriate. Pipeline system operators should avail themselves of new technology as it becomes proven and practical. New technologies may improve an operator's ability to prevent certain types of failures, detect risks more effectively, or improve the mitigation of risks.

Performance measurement of the system and the program itself is an integral part of a pipeline integrity management program. Each operator shall choose significant performance measures at the beginning of the program and then periodically evaluate the results of these measures to monitor and evaluate the effectiveness of the program. Periodic reports of the effectiveness of an operator's integrity management program shall be issued and evaluated in order to continuously improve the program.

Integrity management activities shall be communicated to the appropriate stakeholders. Each operator shall ensure that all appropriate stakeholders are given the opportunity to participate in the risk assessment process and that the results are communicated effectively.

2 INTEGRITY MANAGEMENT PROGRAM OVERVIEW

2.1 General

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 Fig. 2.1-1 are required for all integrity management programs.

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

The process shown in Fig. 2.1-2 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 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 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.

Fig. 2.1-1 Integrity Management Program Elements

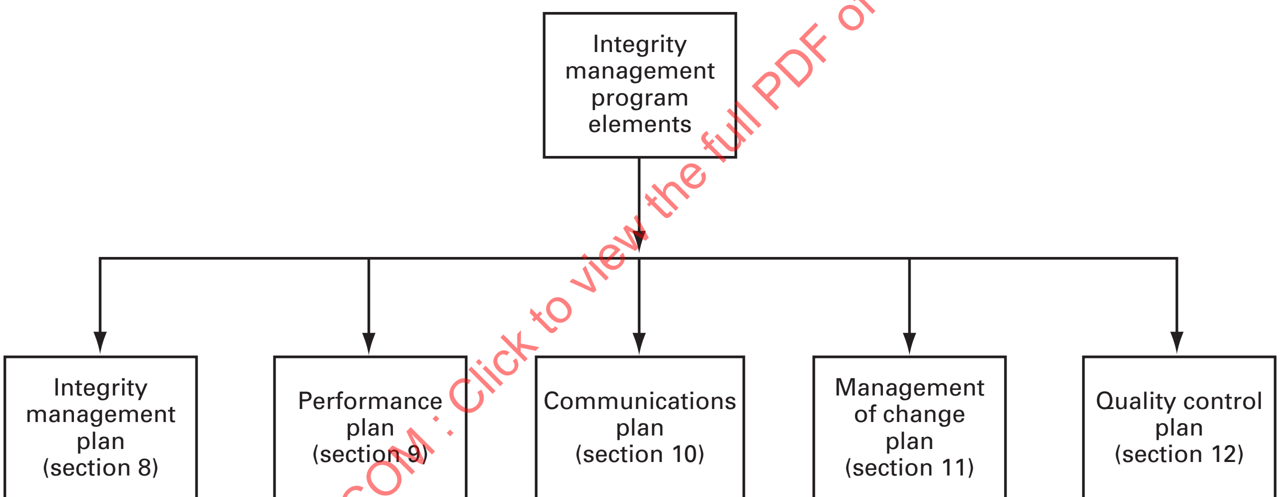
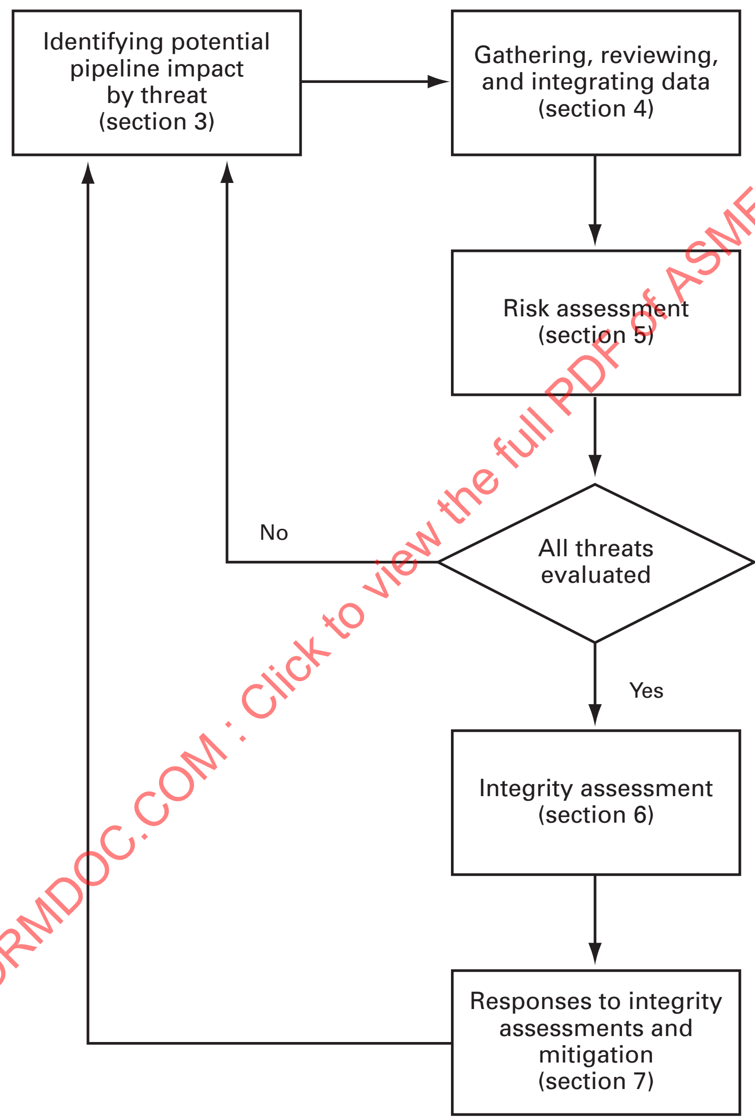


Fig. 2.1-2 Integrity Management Plan Process Flow Diagram



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.

There is no single "best" approach that is applicable to all pipeline systems for all situations. This Code 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 Fig. 2.1-1 are required for all integrity management programs.

The process of managing integrity is an integrated and iterative process. Although the steps depicted in Fig. 2.1-2 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 section 2, as well as instructions to the more specific and detailed description of the individual elements that compose the remainder of this Code. References to the specific detailed sections in this Code are shown in Figs. 2.1-1 and 2.1-2.

2.2 Integrity Threat Classification

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

(a) defective pipe seam

(b) defective pipe

(2) welding/fabrication related

(a) defective pipe girth weld (circumferential) including branch and T joints

(b) defective fabrication weld

(c) wrinkle bend or buckle

(d) stripped threads/broken pipe/coupling failure

(3) equipment

(a) gasket O-ring failure

(b) control/relief equipment malfunction

(c) seal/pump packing failure

(d) miscellaneous

(c) Time-Independent

(1) third party/mechanical damage

(a) damage inflicted by first, second, or third parties (instantaneous/immediate failure)

(b) previously damaged pipe (such as dents and/or gouges) (delayed failure mode)

(c) vandalism

(2) incorrect operational procedure

(3) weather-related and outside force

(a) cold weather

(b) lightning

(c) heavy rains or floods

(d) 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 Nonmandatory Appendix A 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."

2.3 The Integrity Management Process

The integrity management process depicted in Fig. 2.1-2 is described below.

2.3.1 Identify Potential Pipeline Impact by Threat. 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 para. 2.2.

2.3.2 Gathering, Reviewing, and Integrating Data. 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). Section 3 provides information on consequences. Section 4 provides details for data gathering, review, and integration of pipeline data.

2.3.3 Risk Assessment. 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 section 3) 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 Nonmandatory Appendix A). 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. Section 5 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. Nonmandatory Appendix A provides the steps to be followed for a prescriptive program.

2.3.4 Integrity Assessment. 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 para. 6.5. 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. Section 6 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.

2.3.5 Responses to Integrity Assessment, Mitigation (Repair and Prevention), and Setting Inspection Intervals. 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 time-frames 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. Section 7 provides details on repair and prevention techniques.

2.3.6 Update, Integrate, and Review Data. 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.

2.3.7 Reassess Risk. 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.

2.4 Integrity Management Program

The essential elements of an integrity management program are depicted in Fig. 2.1-1 and are described below.

2.4.1 Integrity Management Plan. The integrity management plan is the outcome of applying the process depicted in Fig. 2.1-2 and discussed in section 8. 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 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 8 provides details on plan development.

The plan shall be periodically updated to reflect new information and the current understanding of integrity threats. As new risks or new manifestations 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.

2.4.2 Performance Plan. 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. Section 9 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.

2.4.3 Communications Plan. 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. Section 10 provides further information about communications plans.

2.4.4 Management of Change Plan. 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. Section 11 discusses the important aspects of managing changes as they relate to integrity management.

2.4.5 Quality Control Plan. Section 12 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.

3 CONSEQUENCES

3.1 General

Risk is the mathematical product of the likelihood (probability) and the consequences of events that result 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.

Paragraph 3.2 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.

3.2 Potential Impact Area

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

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

where

d = outside diameter 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.

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

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.

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

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

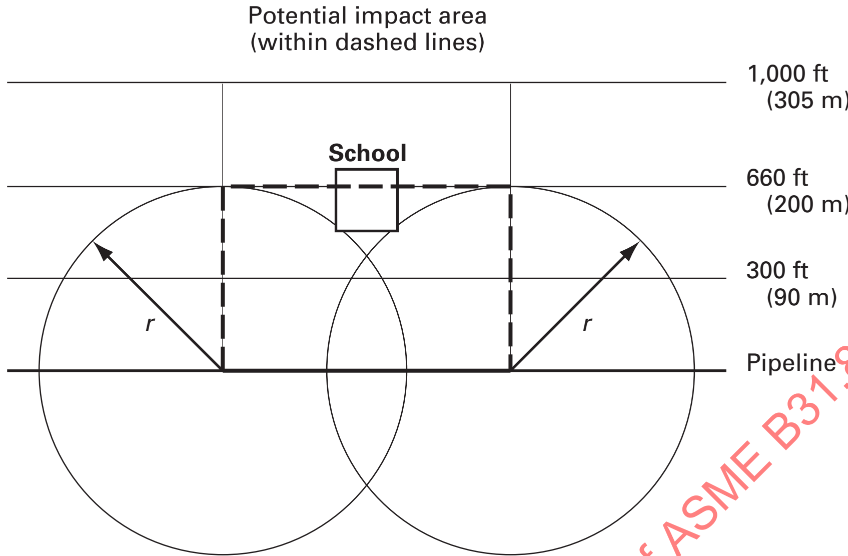
$$r = \sqrt{\frac{115{,}920}{8} \cdot \mu \cdot \chi_g \cdot \lambda \cdot C_d \cdot H_C \cdot \frac{Q}{a_o} \cdot \frac{pd^2}{I_{th}}}$$

where

a_o = sonic velocity of gas = $\sqrt{\dfrac{\gamma RT}{m}}$
C_d = discharge coefficient
d = line diameter
H_C = heat of combustion
I_{th} = threshold heat flux
m = gas molecular weight
p = live pressure
Q = flow factor = $\gamma\left(\dfrac{2}{\gamma+1}\right)^{\frac{\gamma+1}{2(\gamma-1)}}$
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

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

Fig. 3.2-1 Potential Impact Area



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

to the center of the last affected circle (see Fig. 3.2-1). 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 sections 4 and 5).

3.3 Consequence Factors to Consider

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, child-care 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.

4 GATHERING, REVIEWING, AND INTEGRATING DATA

4.1 General

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 Nonmandatory Appendix A.

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.

4.2 Data Requirements

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 section 5). 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.

Table 4.2.1-1 Data Elements for Prescriptive Pipeline Integrity Program

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

4.2.1 Prescriptive Integrity Management Programs. Limited data sets shall be gathered to evaluate each threat for prescriptive integrity management program applications. These data lists are provided in Nonmandatory Appendix A for each threat and summarized in Table 4.2.1-1. 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.

4.2.2 Performance-Based Integrity Management Programs. 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 Nonmandatory Appendix A.

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.

4.3 Data Sources

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 Table 4.3-1 are necessary for integrity management program initiation. As the

Table 4.3-1 Typical Data Sources for Pipeline Integrity Program

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

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 section 9.

4.4 Data Collection, Review, and Analysis

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.

4.5 Data Integration

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.

Table 4.2.1-1 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 Table 4.2.1-1. 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 section 3) 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.

5 RISK ASSESSMENT

5.1 Introduction

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

5.2 Definition

The operator shall follow section 5 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 Nonmandatory Appendix A.

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 (see para. 2.2)

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 section 3.

5.3 Risk Assessment Objectives

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.

5.4 Developing a Risk Assessment Approach

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 section 11).

5.5 Risk Assessment Approaches

(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.

5.6 Risk Analysis

5.6.1 Risk Analysis for Prescriptive Integrity Management Programs. 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 Table 5.6.1-1. 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 para. 5.5 are considered appropriate.

(12) **Table 5.6.1-1 Integrity Assessment Intervals: Time-Dependent Threats, Internal and External Corrosion, Prescriptive Integrity Management Plan**

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.

5.6.2 Risk Analysis for Performance-Based Integrity Management Programs. Performance-based integrity management programs shall prioritize initial integrity assessments utilizing any of the methods described in para. 5.5.

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 Nonmandatory Appendix A 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.

5.7 Characteristics of an Effective Risk Assessment Approach

Considering the objectives summarized in para. 5.3, 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 section 12). 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.*

5.8 Risk Estimates Using Assessment Methods

A description of various details and complexities associated with different risk assessment processes has been provided in para. 5.5. 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 para. 5.5. 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 Table 5.6.1-1. 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.

5.9 Data Collection for Risk Assessment

Data collection issues have been discussed in section 4. 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.

5.10 Prioritization for Prescriptive-Based and Performance-Based Integrity Management Programs

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 Nonmandatory Appendix A. 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.

5.11 Integrity Assessment and Mitigation

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. Section 6 discusses integrity assessment and section 7 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.

5.12 Validation

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.

6 INTEGRITY ASSESSMENT

6.1 General

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 in-line inspection, pressure testing, direct assessment, or other methodologies provided in para. 6.5. 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.

Section 2 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 section 7.

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 section 6 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.

6.2 Pipeline In-Line Inspection

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.

6.2.1 Metal Loss Tools for the Internal and External Corrosion Threat. 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.

6.2.2 Crack Detection Tools for the Stress Corrosion Cracking Threat. 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 SCC, but is not considered accurate for sizing. High inspection speeds can degrade sizing accuracy.

6.2.3 Metal Loss and Caliper Tools for Third-Party Damage and Mechanical Damage Threat. 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.

6.2.4 All Other Threats. In-line inspection is typically not the appropriate inspection method to use for all other threats listed in section 2.

6.2.5 Special Considerations for the Use of In-Line Inspection Tools

(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 important issues that should be considered are as follows:

(1) Pipeline Questionnaire. The questionnaire provides 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.

6.2.6 Examination and Evaluation. 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 section 7.

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 section 7.

6.3 Pressure Testing

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.

6.3.1 Time-Dependent Threats. 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.

6.3.2 Manufacturing and Related Defect Threats. 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 yr prior to the effective date of this Code), 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.

6.3.3 All Other Threats. Pressure testing is typically not the appropriate integrity assessment method to use for all other threats listed in section 2.

6.3.4 Examination and Evaluation. 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.

6.4 Direct Assessment

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.

6.4.1 External Corrosion Direct Assessment (ECDA) for the External Corrosion Threat. 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. (12)

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 is to identify locations where external corrosion defects may have formed. It is recognized that evidence of other threats such as mechanical damage and stress corrosion cracking (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.

6.4.2 Internal Corrosion Direct Assessment Process (ICDA) for the Internal Corrosion Threat. 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 section 4). 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 Nonmandatory Appendix B, section B-2, and the NACE 0206-2006 Standard Practice, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA).

6.4.3 Stress Corrosion Cracking Direct Assessment (SCCDA) for the Stress Corrosion Cracking Threat. 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 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.

6.4.4 All Other Threats. Direct assessment is typically not the appropriate integrity assessment method to use for all other threats listed in section 2.

6.5 Other Integrity Assessment Methodologies

Other proven integrity assessment methods may exist for use in managing the integrity of pipelines. For the purpose of this Code, 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 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.

7 RESPONSES TO INTEGRITY ASSESSMENTS AND MITIGATION (REPAIR AND PREVENTION)

7.1 General

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.

Table 7.1-1 includes a summary of some prevention and repair methods and their applicability to each threat.

7.2 Responses to Pipeline In-Line Inspections

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 mo 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 reinspect rather than examine and evaluate, provided the reinspection is conducted and results obtained within the specified time frame.

7.2.1 Metal Loss Tools for Internal and External Corrosion. 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 7.2.1-1 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 Fig. 7.2.1-1. 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.

7.2.2 Crack Detection Tools for Stress Corrosion Cracking. 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.

7.2.3 Metal Loss and Caliper Tools for Third-Party Damage and Mechanical Damage. 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.

(12)

Table 7.1-1 Acceptable Threat Prevention and Repair Methods

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
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	...	...	...	...

(12)

Table 7.1-1 Acceptable Threat Prevention and Repair Methods (Cont'd)

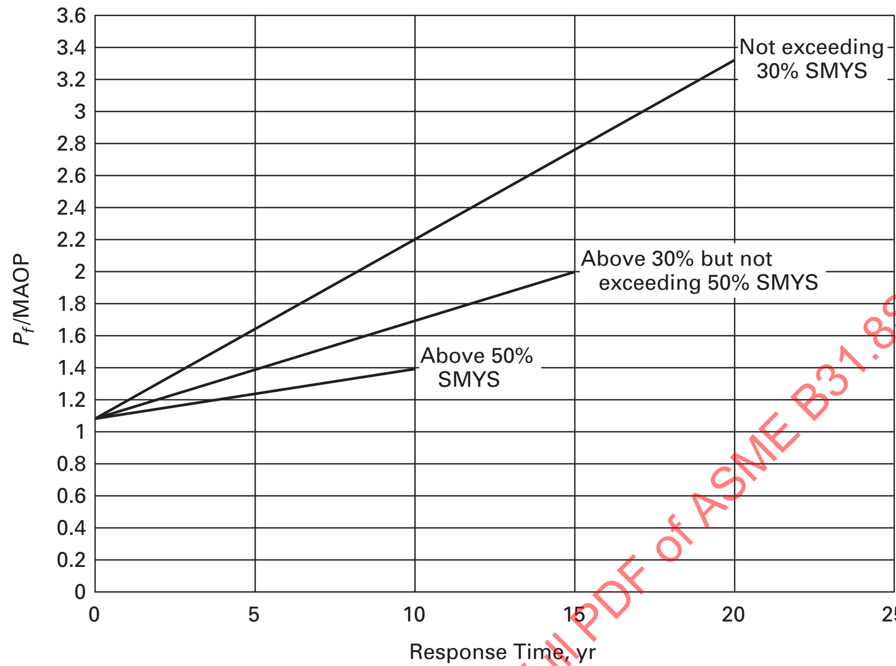
Prevention, Detection, and Repair Methods	Third-Party Damage			Corrosion Related		Equipment				Incorrect Operation	Weather Related			Manufacture		Construction				O-Force	Environ-ment
	TPD(IF)	PDP	Vand	Ext	Int	Gask/ Oring	Strip/ BP	Cont/ Rel	Seal/ Pack	IO	CW	L	HR/F	Pipe Seam	Pipe	Gweld	Fab Weld	Coup	WB/B	EM	SCC
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

Fig. 7.2.1-1 Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan



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.

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 yr 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.

7.2.4 Limitations to Response Times for Prescriptive-Based Program. 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 (see section 14) contains additional guidance for these analyses.

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.

7.2.5 Extending Response Times for Performance-Based Program. 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.

7.3 Responses to Pressure Testing

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

7.3.1 External and Internal Corrosion Threats. The interval between tests for the external and internal corrosion threats shall be consistent with Table 5.6.1-1.

7.3.2 Stress Corrosion Cracking Threat. 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

7.3.3 Manufacturing and Related Defect Threats. 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 yr prior to the effective date of this supplement).

7.4 Responses to Direct Assessment Inspections

7.4.1 External Corrosion Direct Assessment (ECDA). 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 yr, then the reinspection interval shall be 10 yr. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 5 yr, provided an analysis is performed to ensure all remaining defects will not grow to failure in 10 yr. The interval between determination and examination shall be consistent with Fig. 7.2.1-1.

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 yr, the reinspection interval shall be 20 yr. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 10 yr, provided an analysis is performed to ensure all remaining defects will not grow to failure in 20 yr (at an 80% confidence level). The interval between determination and examination shall be consistent with Fig. 7.2.1-1.

7.4.2 Internal Corrosion Direct Assessment (ICDA). For the ICDA prescriptive program, examination and evaluation of all selected locations must be performed within 1 yr of selection. The interval between subsequent examinations shall be consistent with Fig. 7.2.1-1.

7.4.3 Stress Corrosion Cracking Direct Assessment (SCCDA). For the SCCDA prescriptive program, examination and evaluation of all selected locations must be performed within 1 yr 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 Fig. 7.2.1-1 and section A-3 in Nonmandatory Appendix A. Figure 7.2.1-1 and section A-3 in Nonmandatory Appendix A are applicable to prescriptive-based programs. The intervals may be extended for a performance-based program as provided in para. 7.2.5.

7.5 Timing for Scheduled Responses

Figure 7.2.1-1 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 para. 7.2.5.

7.6 Repair Methods

Table 7.1-1 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.

7.7 Prevention Strategy/Methods

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 sections 2, 3, 4, and

5. 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 Nonmandatory Appendix A 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.

7.8 Prevention Options

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 section 7 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 section 2 is presented in Table 7.1-1.

8 INTEGRITY MANAGEMENT PLAN

8.1 General

The integrity management plan is developed after gathering the data (see section 4) and completing the risk assessment (see section 5) 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 section 6). 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 section 7).

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.

8.2 Updating the Plan

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 section 4). 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 section 11).

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.

8.3 Plan Framework

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

8.3.1 Gathering, Reviewing, and Integrating Data. 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 section 4.

8.3.2 Assess Risk. 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 section 5.

8.3.3 Integrity Assessment. Based on the assessment of risk, the appropriate integrity assessments shall be implemented. Integrity assessments shall be conducted 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.

Table 5.6.1-1 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 Nonmandatory Appendix A, para. A-3.4. The assessment schedules for all other threats are identified in appropriate chapters of Nonmandatory Appendix A 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 section 6.

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.

8.3.4 Responses to Integrity Assessment, Mitigation (Repair and Prevention), and Intervals. 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 section 7)

Tables 8.3.4-1, 8.3.4-2, and 8.3.4-3 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.

9 PERFORMANCE PLAN

9.1 Introduction (12)

This section provides the performance plan requirements that apply to both prescriptive- and performance-based integrity management programs.

Table 8.3.4-1 Example of Integrity Management Plan for Hypothetical Pipeline Segment (Segment Data: Line 1, Segment 3)

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

Table 8.3.4-2 Example of Integrity Management Plan for Hypothetical Pipeline Segment (Integrity Assessment Plan: Line 1, Segment 3)

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

Table 8.3.4-3 Example of Integrity Management Plan for Hypothetical Pipeline Segment (Mitigation Plan: Line 1, Segment 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 external or internal 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.

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?

9.2 Performance Measures Characteristics

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.

9.2.1 Process or Activity Measures. 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.

9.2.2 Operational Measures. 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 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.

9.2.3 Direct Integrity Measures. 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 above are illustrated in Table 9.2.3-1.

9.3 Performance Measurement Methodology

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.

9.4 Performance Measurement: Intrasystem

(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

Table 9.2.3-1 Performance Measures

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)

threat-specific metrics for each threat in Nonmandatory Appendix A [see Table 9.4(b)-1]. Additionally, the following overall program measurements shall be determined and documented:

(12) *(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.]

(12) *(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.)

(12) *(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)

(12) *(c)* For operators implementing performance-based programs, the threat-specific metrics shown in Nonmandatory Appendix A 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. Table 9.4(c)-1 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 Table 9.4(c)-1 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 Fig. 2.1-2 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.

(12) **Table 9.4(b)-1 Performance Metrics**

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

(12) **Table 9.4(c)-1 Overall Performance Measures**

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

(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.

(12) (8) Required activities are documented.

(12) (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.

9.5 Performance Measurement: Industry Based

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.

9.6 Performance Improvement

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.

10 COMMUNICATIONS PLAN

10.1 General

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 individuals 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.

10.2 External Communications

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.

10.3 Internal Communications

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.

11 MANAGEMENT OF CHANGE PLAN

(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.

12 QUALITY CONTROL PLAN

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

12.1 General

Quality control as defined for this Code 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.

12.2 Quality Management Control

(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

(12) (b) Specifically, activities to be included in the quality control program are as follows:

(12) (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. (12)

(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.

13 TERMS, DEFINITIONS, AND ACRONYMS (12)

See Fig. 13-1 for the hierarchy of terminology for integrity assessment.

actionable anomaly: anomalies that may exceed acceptable limits based on the operator's anomaly and pipeline data analysis.

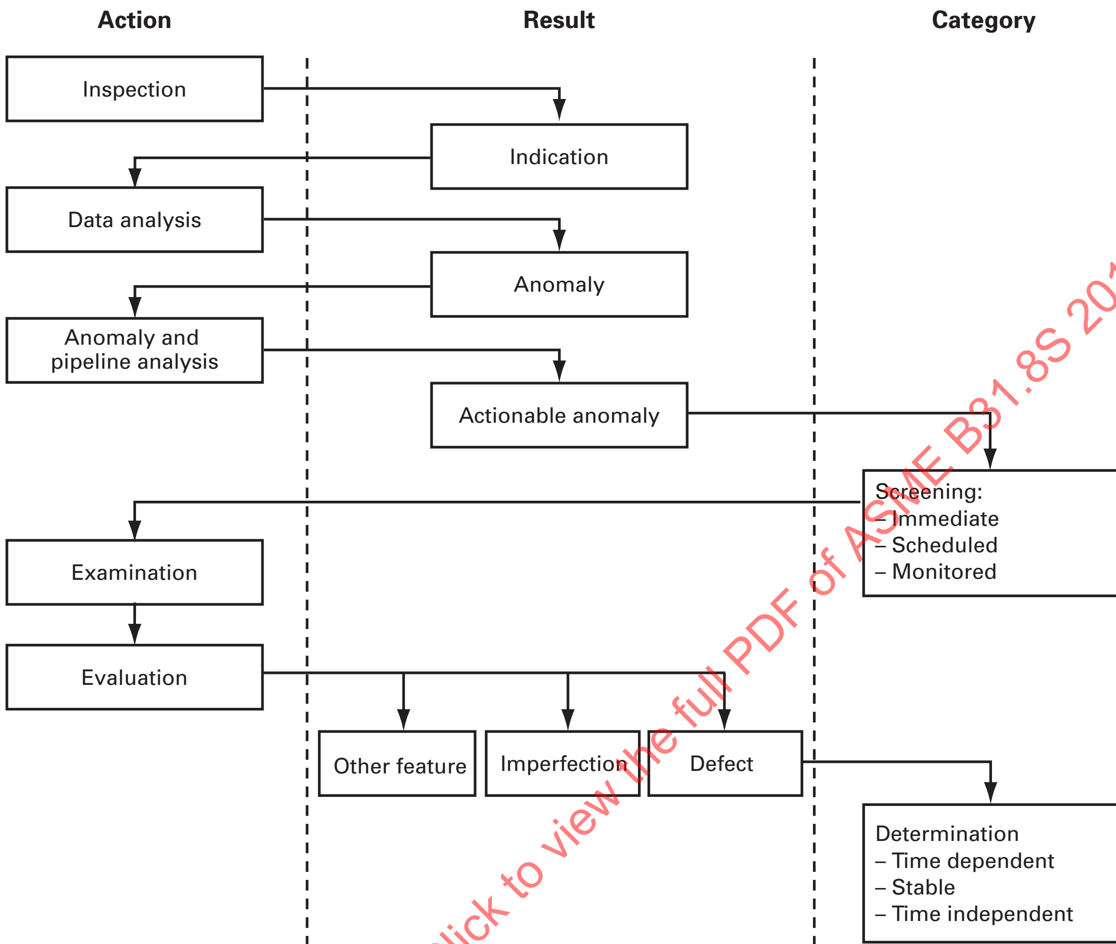
active corrosion: corrosion that is continuing or not arrested.

annular filled saddle: an external steel fabrication, similar to a sleeve, except one half is pierced and forged to provide a close fit around a hot tap "T." The other half away from the "T" is joined with seam welds like a type A sleeve. The annular space between the pressure containing pipes and the saddle is filled with an incompressible material to provide mechanical support to the welded "T."

anomaly: an unexamined deviation from the norm in pipe material, coatings, or welds.

anomaly and pipeline data analysis: the process through which anomaly and pipeline data are integrated and analyzed to further classify and characterize anomalies.

Fig. 13-1 Hierarchy of Terminology for Integrity Assessment



arc welding or arc weld: group of welding processes that produces coalescence by heating them with an arc. The processes are used with or without the application of pressure and with or without filler metal.

backfill: material placed in a hole or trench to fill excavated space around a pipeline or other appurtenances.

batch: a volume of liquid that flows en masse in a pipeline physically separated from adjacent volume(s) of liquid or gas. [Sealing (batching) pigs are typically used for separation.]

bell hole: excavation that minimizes surface disturbance yet provides sufficient room for examination or repair of buried facilities.

buckle: condition in which the pipeline has undergone sufficient plastic deformation to cause permanent wrinkling in the pipe wall or excessive cross-sectional deformation caused by bending, axial, impact, and/or torsional loads acting alone or in combination with hydrostatic pressure.

butt joint: a joint between two members aligned approximately in the same plane. See Figs. 1(A), 2(A), 3, 51(A), and 51(B) in AWS A3.0.

butt weld: a nonstandard term for a weld in a butt joint.

calibration dig: exploratory excavation to validate findings of an in-line inspection tool with the purpose of improving data interpretation.

caliper tool or geometry tool: an instrumented in-line inspection tool designed to record conditions, such as dents, wrinkles, ovality, bend radius, and angle, by sensing the shape of the internal surface of the pipe.

carbon dioxide: a heavy, colorless gas that does not support combustion, dissolves in water to form carbonic acid, and is found in some natural gas streams.

cast iron: unqualified term "cast iron" shall apply to gray cast iron, which is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed throughout the metal.

cathodic protection (CP): technique to reduce the corrosion of a metal surface by making that surface the cathode of an electromechanical cell.

certification: written testimony of qualification.

characterize: to qualify the type, size, shape, orientation, and location of an anomaly.

close interval survey (CIS): inspection technique that includes a series of aboveground pipe-to-soil potential measurements taken at predetermined increments of a few to several feet (meters) along the pipeline and used to provide information on the effectiveness of the cathodic protection system.

coating: liquid, liquefiable, or mastic composition that, after application to a surface, is converted into a solid protective, decorative, or functional adherent film. Coating also includes tape wrap.

coating system: complete number and types of coats applied to a substrate in a predetermined order. (When used in a broader sense, surface preparation, pretreatments, dry film thickness, and manner of application are included.)

component or pipeline component: an individual item or element fitted in line with pipe in a pipeline system, such as, but not limited to, valves, elbows, tees, flanges, and closures.

composite repair sleeve: permanent repair method using composite sleeve material, which is applied with an adhesive.

consequence: impact that a pipeline failure could have on the public, employees, property, and the environment.

corrosion: deterioration of a material, usually a metal, that results from an electrochemical reaction with its environment.

corrosion inhibitor: chemical substance or combination of substances that, when present in the environment or on a surface, prevents or reduces corrosion.

corrosion rate: rate at which corrosion proceeds.

crack: very narrow, elongated defect caused by mechanical splitting into two parts.

current: flow of electric charge.

data analysis: the evaluation process through which inspection indications are classified and characterized.

defect: a physically examined anomaly with dimensions or characteristics that exceed acceptable limits.

dent: permanent deformation of the circular cross-section of the pipe that produces a decrease in the diameter and is concave inward.

detect: to sense or obtain measurable wall loss indications from an anomaly in a steel pipeline using in-line inspection or other technologies.

diameter or nominal outside diameter: as-produced or as-specified outside diameter of the pipe, not to be confused with the dimensionless NPS (DN). For example, NPS 12 (DN 300) pipe has a specified outside diameter of 12.750 in. (323.85 mm), NPS 8 (DN 200) pipe has a specified outside diameter of 8.625 in. (219.08 mm), and NPS 24 pipe has a specified outside diameter of 24.000 in. (609.90 mm).

direct current voltage gradient (DCVG): inspection technique that includes aboveground electrical measurements taken at predetermined increments along the pipeline and is used to provide information on the effectiveness of the coating system.

discontinuity: an interruption of the typical structure of a material, such as a lack of homogeneity in its mechanical, metallurgical, or physical characteristics. A discontinuity is not necessarily a defect.

documented: condition of being in written form.

double submerged-arc welded pipe (DSAW pipe): pipe that has a straight longitudinal or helical seam containing filler metal deposited on both sides of the joint by the submerged-arc welded process.

ductility: measure of the capability of a material to be deformed plastically before fracturing.

electric resistance welded pipe (ERW pipe): pipe that has a straight longitudinal seam produced without the addition of filler metal by the application of pressure and heat obtained from electrical resistance. ERW pipe forming is distinct from flash welded pipe and furnace butt-welded pipe as a result of being produced in a continuous forming process from coils of flat plate.

electrolyte: medium containing ions that migrate in an electric field.

engineering assessment: a documented assessment, using engineering principles, of the effect of relevant variables upon service or integrity of a pipeline system, using engineering principles, and conducted by, or under the supervision of, a competent person with demonstrated understanding and experience in the application of the engineering and risk management principles related to the issue being assessed.

engineering critical assessment: an analytical procedure, based upon fracture mechanics, that allows determination of the maximum tolerable sizes for imperfections, and conducted by, or under the supervision of, a competent person with demonstrated understanding and experience in the application of the engineering principles related to the issue being assessed.

environment: surroundings or conditions (physical, chemical, mechanical) in which a material exists.

epoxy: type of resin formed by the reaction of aliphatic or aromatic polyols (like bisphenol) with epichlorohydrin and characterized by the presence of reactive oxirane end groups.

evaluation: a review, following the characterization of an actionable anomaly, to determine whether the anomaly meets specified acceptance criteria.

examination: direct physical inspection of a pipeline that may include the use of nondestructive examination (NDE) techniques or methods.

experience: work activities accomplished in a specific NDT method under the direction of qualified supervision including the performance of the NDT method and related activities but not including time spent in organized training programs.

failure: general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use.

fatigue: process of development of or enlargement of a crack as a result of repeated cycles of stress.

feature: any physical object detected by an in-line inspection system. Features may be anomalies, components, nearby metallic objects, welds, or some other item.

film: thin, not necessarily visible layer of material.

galvanic corrosion: accelerated corrosion of a metal because of an electrical contact with a more noble metal and/or a more noble localized section of the metal or nonmetallic conductor in a corrosive electrolyte.

gas: as used in this Code, any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. The common types are natural gas, manufactured gas, and liquefied petroleum gas distributed as a vapor, with or without the admixture of air.

gas processing plant: facility used for extracting commercial products from gas.

gathering system: one or more segments of pipeline, usually interconnected to form a network, that transports gas from one or more production facilities to the inlet of a gas processing plant. If no gas processing plant exists, the gas is transported to the most downstream of either of the following:

(a) the point of custody transfer of gas suitable for delivery to a distribution system

(b) the point where accumulation and preparation of gas from separate geographic production fields in reasonable proximity has been completed

geographic information system (GIS): system of computer software, hardware, data, and personnel to help manipulate, analyze, and present information that is tied to a geographic location.

girth weld: complete circumferential butt weld joining pipe or components.

global positioning system (GPS): system used to identify the latitude and longitude of locations using GPS satellites.

gouge: mechanically induced metal-loss, which causes localized elongated grooves or cavities in a metal pipeline.

high-pressure distribution system: gas distribution piping system that operates at a pressure higher than the standard service pressure delivered to the customer. In such a system, a service regulator is required on each service line to control the pressure delivered to the customer.

hydrogen-induced damage: form of degradation of metals caused by exposure to environments (liquid or gas) that allows absorption of hydrogen into the material. Examples of hydrogen-induced damage are formation of internal cracks, blisters, or voids in steels; embrittlement (i.e., loss of ductility); and high-temperature hydrogen attack (i.e., surface decarburization and chemical reaction with hydrogen).

hydrogen sulfide (H_2S): toxic gaseous impurity found in some well gas streams. It also can be generated in situ as a result of microbiologic activity.

hydrostatic test or hydrotest: a pressure test using water as the test medium.

imperfection: an anomaly with characteristics that do not exceed acceptable limits.

incident: unintentional release of gas due to the failure of a pipeline.

inclusion: nonmetallic phase such as an oxide, sulfide, or silicate particle in a metal pipeline.

indication: finding of a nondestructive testing technique or method that deviates from the expected. It may or may not be a defect.

in-line inspection (ILI): steel pipeline inspection technique that uses devices known in the industry as intelligent or smart pigs. These devices run inside the pipe and provide indications of metal loss, deformation, and other defects.

in-line inspection tools: any instrumented device or vehicle that records data and uses nondestructive test methods or other techniques to inspect the pipeline from the inside. These tools are also known as intelligent pigs or smart pigs.

in-service pipeline: defined here as a pipeline that contains natural gas to be transported. The gas may or may not be flowing.

inspection: use of a nondestructive testing technique or method.

integrity: defined here as the capability of the pipeline to withstand all anticipated loads (including hoop stress due to operating pressure) plus the margin of safety established by this section.

integrity assessment: process that includes inspection of pipeline facilities, evaluating the indications resulting from the inspections, examining the pipe using a variety of techniques, evaluating the results of the examinations, characterizing the evaluation by defect type and severity, and determining the resulting integrity of the pipeline through analysis.

launcher: pipeline facility used to insert a pig into a pressurized pipeline, sometimes referred to as a "pig trap."

leak: unintentional escape of gas from the pipeline. The source of the leak may be holes, cracks (include propagating and nonpropagating, longitudinal, and circumferential), separation or pullout, and loose connections.

length: a piece of pipe of the length delivered from the mill. Each piece is called a length, regardless of its actual dimension. This is sometimes called a "joint," but "length" is preferred.

liquefied petroleum gas(es) (LPG): liquid petroleum gases composed predominantly of the following hydrocarbons, either by themselves or as mixtures: butane (normal butane or isobutane), butylene (including isomers), propane, propylene, and ethane. LPG can be stored as liquids under moderate pressures (approximately 80 psig [550 kPa] to 250 psig [1 720 kPa]) at ambient temperatures.

low-pressure distribution system: gas distribution piping system in which the gas pressure in the mains and service lines is substantially the same as that delivered to the customer's appliances. In such a system, a service regulator is not required on the individual service lines.

low stress pipeline: pipeline that is operated in its entirety at a hoop stress level of 20% or less of the specified minimum yield strength of the line pipe.

magnetic flux leakage (MFL): an in-line inspection technique that induces a magnetic field in a pipe wall between two poles of a magnet. Sensors record status in leakage in this magnetic flux (flow) outside the pipe wall, which can be correlated to metal loss.

magnetic particle inspection (MPI): a nondestructive test method utilizing magnetic leakage fields and suitable indicating materials to disclose surface and near-surface discontinuity indications.

management of change: process that systematically recognizes and communicates to the necessary parties changes of a technical, physical, procedural, or organizational nature that can impact system integrity.

maximum allowable operating pressure (MAOP): maximum pressure at which a pipeline system may be operated in accordance with the provisions of the ASME B31.8 Code.

mechanical damage: type of metal damage in a pipe or pipe coating caused by the application of an external force. Mechanical damage can include denting, coating removal, metal removal, metal movement, cold working of the underlying metal, puncturing, and residual stresses.

metal loss: types of anomalies in pipe in which metal has been removed from the pipe surface, usually due to corrosion or gouging.

microbiologically influenced corrosion (MIC): corrosion or deterioration of metals resulting from the metabolic activity of microorganisms. Such corrosion may be initiated or accelerated by microbial activity.

mitigation: limitation or reduction of the probability of occurrence or expected consequence for a particular event.

municipality: city, county, or any other political subdivision of a State.

nondestructive examination (NDE) or nondestructive testing (NDT): testing method, such as radiography, ultrasonic, magnetic testing, liquid penetrant, visual, leak testing, eddy current, and acoustic emission, or a testing technique, such as magnetic flux leakage, magnetic particle inspection, shear-wave ultrasonic, and contact compression-wave ultrasonic.

operating stress: stress in a pipe or structural member under normal operating conditions.

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.

performance-based integrity management program: integrity management process that utilizes risk management principles and risk assessments to determine prevention, detection, and mitigation actions and their timing.

pig: device run inside a pipeline to clean or inspect the pipeline, or to batch fluids.

pigging: use of any independent, self-contained device, tool, or vehicle that moves through the interior of the pipeline for inspecting, dimensioning, cleaning, or drying.

pipe: a tubular product, including tubing, made for sale as a production item, used primarily for conveying a fluid and sometimes for storage. Cylinders formed from plate during the fabrication of auxiliary equipment are not pipe as defined herein.

pipe grade: portion of the material specification for pipe, which includes specified minimum yield strength.

pipeline: all parts of physical facilities through which gas moves in transportation, including: pipe, valves, fittings, flanges (including bolting and gaskets), regulators, pressure vessels, pulsation dampeners, relief valves, appurtenances attached to pipe, compressor units, metering facilities, pressure regulating stations, pressure relief stations, and fabricated assemblies. Included within this definition are gas transmission and gathering lines, which transport gas from production facilities to onshore locations, and gas storage equipment of the closed-pipe type, which is fabricated or forged from pipe or fabricated from pipe and fittings.

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

pipeline section: continuous run of pipe between adjacent compressor stations, between a compressor station and a block valve, or between adjacent block valves.

pipe-to-soil potential: electric potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

piping and instrumentation diagram (P&ID): drawing showing the piping and instrumentation for a pipeline or pipeline facility.

pitting: localized corrosion of a metal surface that is confined to a small area and takes the form of cavities called pits.

predicted failure pressure, P_f: an internal pressure that is used to prioritize a defect as immediate, scheduled, or monitored. See the detail explanation with Fig. 7.2.1-1. The failure pressure is calculated utilizing B31G or similar method when the design factor, F, is set to unity.

prescriptive integrity management program: integrity management process that follows preset conditions that result in fixed inspection and mitigation activities and timelines.

pressure: unless otherwise stated, pressure is expressed in pounds per square inch (kilopascals) above atmospheric pressure (i.e., gage pressure), and is abbreviated as psig (kPa).

pressure test: means by which the integrity of a piece of equipment (pipe) is assessed, in which the item is filled with a fluid, sealed, and subjected to pressure. It is used to validate integrity and detect construction defects and defective materials.

probability: likelihood of an event occurring.

qualification: demonstration and documented knowledge, skills, and abilities, along with documented training and/or experience required for personnel to properly perform the duties of a specific job or task.

receiver: pipeline facility used for removing a pig from a pressurized pipeline; sometimes referred to as a "pig trap."

residual stress: stress present in an object in the absence of any external loading, typically resulting from manufacturing or construction processes.

resistivity:

(a) resistance per unit length of a substance with uniform cross-section

(b) measure of the ability of an electrolyte (e.g., soil) to resist the flow of electric charge (e.g., cathodic protection current)

Resistivity data are used to design a groundbed for a cathodic protection system.

rich gas: gas that contains significant amounts of hydrocarbons or components that are heavier than methane and ethane. Rich gases decompress in a different fashion than pure methane or ethane.

right-of-way (ROW): strip of land on which pipelines, railroads, power lines, roads, highways, and other similar facilities are constructed. The ROW agreement secures the right to pass through property owned by others. ROW agreements generally allow the right of ingress and egress for the operation and maintenance of the facility, and the installation of the facility. The ROW width can vary with the construction and maintenance requirements of the facility's operator and is usually determined based on negotiation with the affected landowner, by legal action, or by permitting authority.

risk: measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.

risk assessment: systematic process in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and can be performed at varying level of detail depending on the operator's objectives (see section 5).

risk management: overall program consisting of identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.

root cause analysis: family of processes implemented to determine the primary cause of an event. These processes all seek to examine a cause-and-effect relationship through the organization and analysis of data. Such processes are often used in failure analyses.

rupture: complete failure of any portion of the pipeline that allows the product to escape to the environment.

rust: corrosion product consisting of various iron oxides and hydrated iron oxides. (This term properly applies only to iron and ferrous alloys.)

seam weld: longitudinal or helical seam in pipe, which is made in the pipe mill for the purpose of making a complete circular cross-section.

segment: length of pipeline or part of the system that has unique characteristics in a specific geographic location.

sensors: devices that receive a response to a stimulus (e.g., an ultrasonic sensor detects ultrasound).

shall: "shall" or "shall not" are used to indicate that a provision is mandatory.

shielding: preventing or diverting the flow of cathodic protection current from its natural path.

should: "should," "should not," or "it is recommended" are used to indicate that a provision is not mandatory but recommended as good practice.

sizing accuracy: given by the interval within which a fixed percentage of all metal-loss features will be sized. The fixed percentage is stated as the confidence level.

smart pig: see *in-line inspection tools*.

soil liquefaction: soil condition, typically caused by dynamic cyclic loading (e.g., earthquake, waves) where the effective shear strength of the soil is reduced such that the soil exhibits the properties of a liquid.

specified minimum yield strength (SMYS): expressed in pounds per square inch (MPa), minimum yield strength prescribed by the specification under which pipe is purchased from the manufacturer.

storage field: geographic field containing a well or wells that are completed for and dedicated to subsurface storage of large quantities of gas for later recovery, transmission, and end use.

strain: change in length of a material in response to an applied force, expressed on a unit length basis (e.g., inches per inch or millimeters per millimeter).

stress: internal resistance of a body to an external applied force, expressed in units of force per unit area (psi or MPa). It may also be termed "unit stress."

stress corrosion cracking (SCC): form of environmental attack of the metal involving an interaction of a local corrosive environment and tensile stresses in the metal, resulting in formation and growth of cracks.

stress level: level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

subject matter experts: individuals that have expertise in a specific area of operation or engineering.

submerged arc welding: arc welding process that uses an arc or arcs between a bare metal electrode or electrodes and the weld pool. The arc and molten metal are shielded by a blanket of granular flux on the workpieces. The process is used without pressure and with filler metal from the electrode and sometimes from a supplemental source (welding rod, flux, or metal granules).

survey: measurements, inspections, or observations intended to discover and identify events or conditions that indicate a departure from normal operation or undamaged condition of the pipeline.

system or pipeline system: either the operator's entire pipeline infrastructure or large portions of that infrastructure that have definable starting and stopping points.

temperature: expressed in degrees Farenheit (°F) [degrees Celsius (°C)].

tensile stress: applied pulling force divided by the original cross-sectional area.

third-party damage: damage to a gas pipeline facility by an outside party other than those performing work for the operator. For the purposes of this Code, this also includes damage caused by the operator's personnel or the operator's contractors.

tool: generic term signifying any type of instrumented tool or pig.

training: organized program developed to impart the knowledge and skills necessary for qualification.

transmission line: segment of pipeline installed in a transmission system or between storage fields.

transmission system: one or more segments of pipeline, usually interconnected to form a network, that transports gas from a gathering system, the outlet of a gas processing plant, or a storage field to a high- or low-pressure distribution system, a large-volume customer, or another storage field.

transportation of gas: gathering, transmission, or distribution of gas by pipeline or the storage of gas.

ultrasonic: high-frequency sound. Ultrasonic examination is used to determine wall thickness and to detect the presence of defects.

uprating: qualifying of an existing pipeline or main for a higher maximum allowable operating pressure.

weld: localized coalescence of metals or nonmetals produced by heating the materials to the welding temperature, with or without the application of pressure, or by the application of pressure alone and with or without the use of filler material.

welding procedures: detailed methods and practices involved in the production of a weldment.

wrinkle bend: pipe bend produced by field machine or controlled process that may result in prominent contour discontinuities on the inner radius. The wrinkle is deliberately introduced as a means of shortening the inside meridian of the bend. Note that this definition does not apply to a pipeline bend in which incidental minor, smooth ripples are present.

14 REFERENCES AND STANDARDS (12)

The following is a list of publications that support or are referenced in this Standard. The references shall be to the specific editions cited below, except the user may use the latest published edition of ANSI approved standards unless specifically prohibited by this Standard, and providing the user has reviewed the latest edition of the standard to ensure that the integrity of the pipeline system is not compromised. If a newer or amended edition of a standard is not ANSI approved, then the user shall use the specific edition reference date shown herein. An asterisk (*) is used to indicate that the specific edition of the standard has been accepted as an American National Standard by the American National Standards Institute (ANSI).

*ANSI/GPTC-Z380-TR-1 (November 2001), Review of Integrity Management for Natural Gas Transmission Pipelines

Publisher: Gas Piping Technology Committee (GPTC) of the American Gas Association (AGA), 400 N. Capitol Street, NW, Washington, DC 20001 (www.aga.org)

*ANSI/ISO/ASQ Q9004-2000, Quality Management Systems: Guidelines for Performance Improvements

Publisher: American Society for Quality (ASQ), P.O. Box 3005, Milwaukee, WI 53201 (www.asq.org)

*API Std 1160, 1st Edition, November 2001 (Reaffirmed November 2008), Managing System Integrity for Hazardous Liquid Pipelines

*API RP 1162, 1st Edition, December 2003, Recommended Practice, Public Awareness Programs for Pipeline Operators

API 1163, In-Line Inspection Systems Qualifications

Publisher: American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005 (www.api.org)

*ASME B31.8, Gas Transmission and Distribution Piping Systems (2007)

*ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B31 Code for Pressure Piping (2009)

ASME CRTD-Vol. 40-1, Risk-Based In-Service Testing — Development of Guidelines, Volume 1: General Document (2000)

ASME Research Report, History of Line Pipe Manufacturing in North America (1996)

ASME STP-PT-011, Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas, October 31, 2008

IPC2002-27124, "Development of Acceptance Criteria for Mild Ripples in Pipeline Field Bends," Proceedings of IPC2002, 4th International Pipeline Conference, September 2002

IPC2002-27131, Qualification of Procedures for Welding Onto In-Service Pipelines

IPC2006-10163, "Method for Establishing Hydrostatic Re-Test Intervals for Pipelines With Stress Corrosion Cracking," Proceedings of IPC2006, 6th International Pipeline Conference, September 2006

IPC2006-10299, Comparison of Methods for Predicting Safe Parameters for Welding Onto In-Service Pipelines

IPC2008-64353, Improved Burnthrough Prediction Model for In-Service Welding Applications

Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Dept.: 22 Law Drive, P.O. Box 2900, Fairfield, NJ 07007-2900 (www.asme.org)

Common Ground Alliance, Best Practices Version 6.0 – February 2009

Publisher: Common Ground Alliance (CGA), 1421 Prince Street, Alexandria, VA 22314 (www.commongroundalliance.com)

GRI-00/0076, Evaluation of Pipeline Design Factors (2000)

GRI-00/0077, Safety Performance of Natural Gas Transmission and Gathering Systems Regulated by Office of Pipeline Safety (2000)

GRI-00/0189, Model for Sizing High Consequence Areas Associated With Natural Gas Pipelines (2000)

GRI-00/0192, GRI Guide for Locating and Using Pipeline Industry Research (2000)

GRI-00/0193, Natural Gas Transmission Pipelines: Pipeline Integrity — Prevention, Detection, & Mitigation Practices (2000)

GRI-00/0228, Cost of Periodically Assuring Pipeline Integrity in High Consequence Areas by In-Line Inspection, Pressure Testing and Direct Assessment (2000)

GRI-00/0230, Periodic Re-Verification Intervals for High-Consequence Areas (2000)

GRI-00/0231, Direct Assessment and Validation (2000)

GRI-00/0232, Leak Versus Rupture Considerations for Steel Low-Stress Pipelines (2000)

GRI-00/0233, Quantifying Pipeline Design at 72% SMYS as a Precursor to Increasing the Design Stress Level (2000)

GRI-00/0246, Implementation Plan for Periodic Re-Verification Intervals for High-Consequence Areas (2000)

GRI-00/0247, Introduction to Smart Pigging in Natural Gas Pipelines (2000)

GRI-01/0027, Pipeline Open Data Standard (PODS) (2001)

GRI-01/0083, Review of Pressure Retesting for Gas Transmission Pipelines (2001)

GRI-01/0084, Proposed New Guidelines for ASME B31.8 on Assessment of Dents and Mechanical Damage (2001)

GRI-01/0085, Schedule of Responses to Corrosion-Caused Metal Loss Revealed by Integrity-Assessment Results (2001)

GRI-01/0111, Determining the Full Cost of a Pipeline Incident (2001)

GRI-01/0154, Natural Gas Pipeline Integrity Management Committee Process Overview Report (2001)

GRI-04/0178, Effect of Pressure Cycles on Gas Pipelines (2004)
GRI-95/0228.1, Natural Gas Pipeline Risk Management, Volume I: Selected Technical Terminology (1995)
GRI-95/0228.2, Natural Gas Pipeline Risk Management, Volume II: Search of Literature Worldwide on Risk Assessment/Risk Management for Loss of Containment (1995)
GRI-95/0228.3, Natural Gas Pipeline Risk Management, Volume III: Industry Practices Analysis (1995)
GRI-95/0228.4, Natural Gas Pipeline Risk Management, Volume IV: Identification of Risk Management Methodologies (1995)
Publisher: Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018 (www.gastechnology.org)

Integrity Characteristics of Vintage Pipelines (2005)
Publisher: The INGAA Foundation, Inc. (INGAA), 20 F Street, NW, Washington, DC 20001 (www.ingaa.org)

Juran's Quality Handbook (5th Edition 2000)
Publisher: McGraw-Hill Company, 1221 Avenue of the Americas, New York, NY 10020-1095 (www.mcgraw-hill.com)

NACE SP0106-2006, Control of Internal Corrosion in Steel Pipelines and Piping Systems
NACE SP0169-2007, Control of External Corrosion on Underground or Submerged Metallic Piping Systems
NACE SP0204-2008, Stress Corrosion Cracking Direct Assessment (SCCDA) Methodology
NACE SP0206-2006, Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)
NACE SP0502-2008, Pipeline External Corrosion Direct Assessment Methodology
Publisher: National Association of Corrosion Engineers (NACE) International, 1440 South Creek Drive, Houston, TX 77084-4906 (www.nace.org)

Pipeline Risk Management Manual (3rd Edition 2004)
Publisher: Gulf Publishing Company, P.O. Box 2608, Houston, TX 77252 (www.gulfpub.com)

Plant Guidelines for Technical Management of Chemical Process Safety (revised edition) 1992
Publisher: Center for Chemical Process Safety (CCPS) of the American Institute of Chemical Engineers (AIChE), Three Park Avenue, New York, NY 10016 (www.aiche.org)

PR-218-9801 (2001), Analysis of DOT Reportable Incidents for Gas Transmission and Gathering System Pipelines, 1985–1997
PR-268-9823 (2004), Guidelines for the Seismic Design and Assessment of Natural Gas and Liquid Hydrocarbon Pipelines
Publisher: Pipeline Research Council International, Inc. (PRCI), 3141 Fairview Park Drive, Falls Church, VA 22042 (www.prci.org)

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NONMANDATORY APPENDIX A THREAT PROCESS CHARTS AND PRESCRIPTIVE INTEGRITY MANAGEMENT PLANS

This Nonmandatory Appendix provides process charts and the essentials of a prescriptive integrity management plan for the nine categories of threats listed in the main body of this Code. The required activities and intervals are not applicable for severe conditions that the operator may encounter. In those instances, more rigorous analysis and more frequent inspection may be necessary.

A-1 EXTERNAL CORROSION THREAT

A-1.1 Scope

Section A-1 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, of external corrosion (see Fig. A-1.1-1). 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.

A-1.2 Gathering, Reviewing, and Integrating Data

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.

A-1.3 Criteria and Risk Assessment

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.

In no case shall the interval between construction and the first required reassessment of integrity exceed 10 yr for pipe operating above 60% SMYS, 13 yr for pipe operating above 50% SMYS and at or below 60% SMYS, 15 yr for pipe operating at or above 30% SMYS and at or below 50% SMYS, and 20 yr 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 in para. A-1.5.

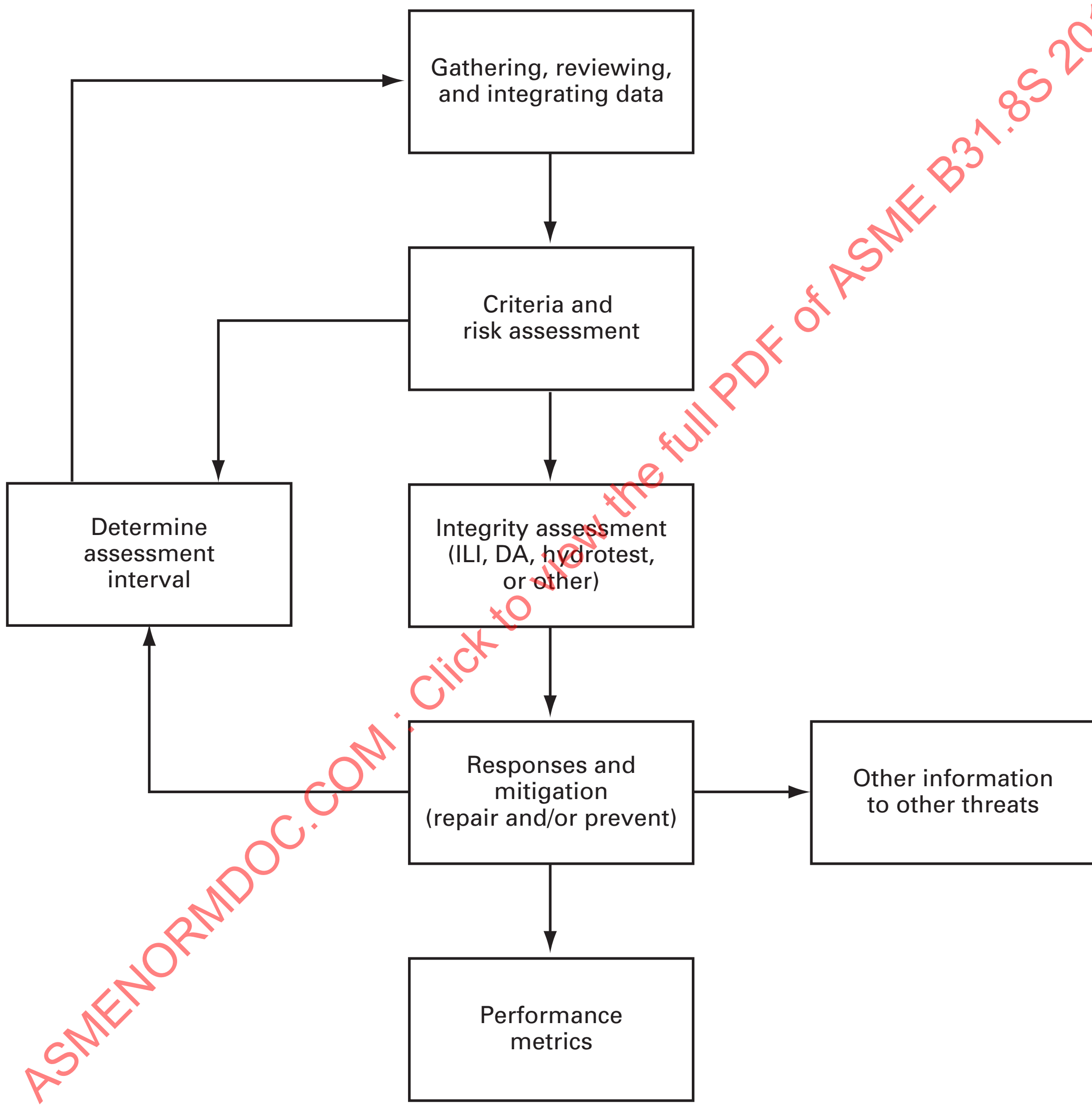
Previous integrity assessments can be considered as meeting these requirements, provided the inspections have equal or greater rigor than that provided by the prescribed inspections in this Code. The interval between the previous integrity assessment and the next integrity assessment cannot exceed the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

A-1.4 Integrity Assessment

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. The operator shall consult section 6 of this Code, 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.

Fig. A-1.1-1 Integrity Management Plan, External Corrosion Threat (Simplified Process: Prescriptive)



(b) *Pressure Test.* The operator shall consult section 6 of this Code, 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 section 6 of this Code, which defines the process, tools, and inspections. The operator selects the appropriate tools and he/she or his/her representative performs the inspections.

A-1.5 Responses and Mitigation

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 section 7 for responses to integrity assessment.

(b) *Direct Assessment.* The response is dependent on the number of indications examined, evaluated, and repaired. Refer to section 7 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 yr. If the test pressure was at least 1.25 times MAOP, the interval shall be 5 yr (see section 7).

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 section 7.

The operator shall select the appropriate prevention practices as outlined in section 7.

A-1.6 Other Data

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.

A-1.7 Assessment Interval

The operator is required to assess integrity periodically. The interval for assessments is dependent on the responses taken as outlined in para. A-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 in section 11.

A-1.8 Performance Measures

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)

A-2 INTERNAL CORROSION THREAT

A-2.1 Scope

Section A-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 Fig. A-2.1-1).

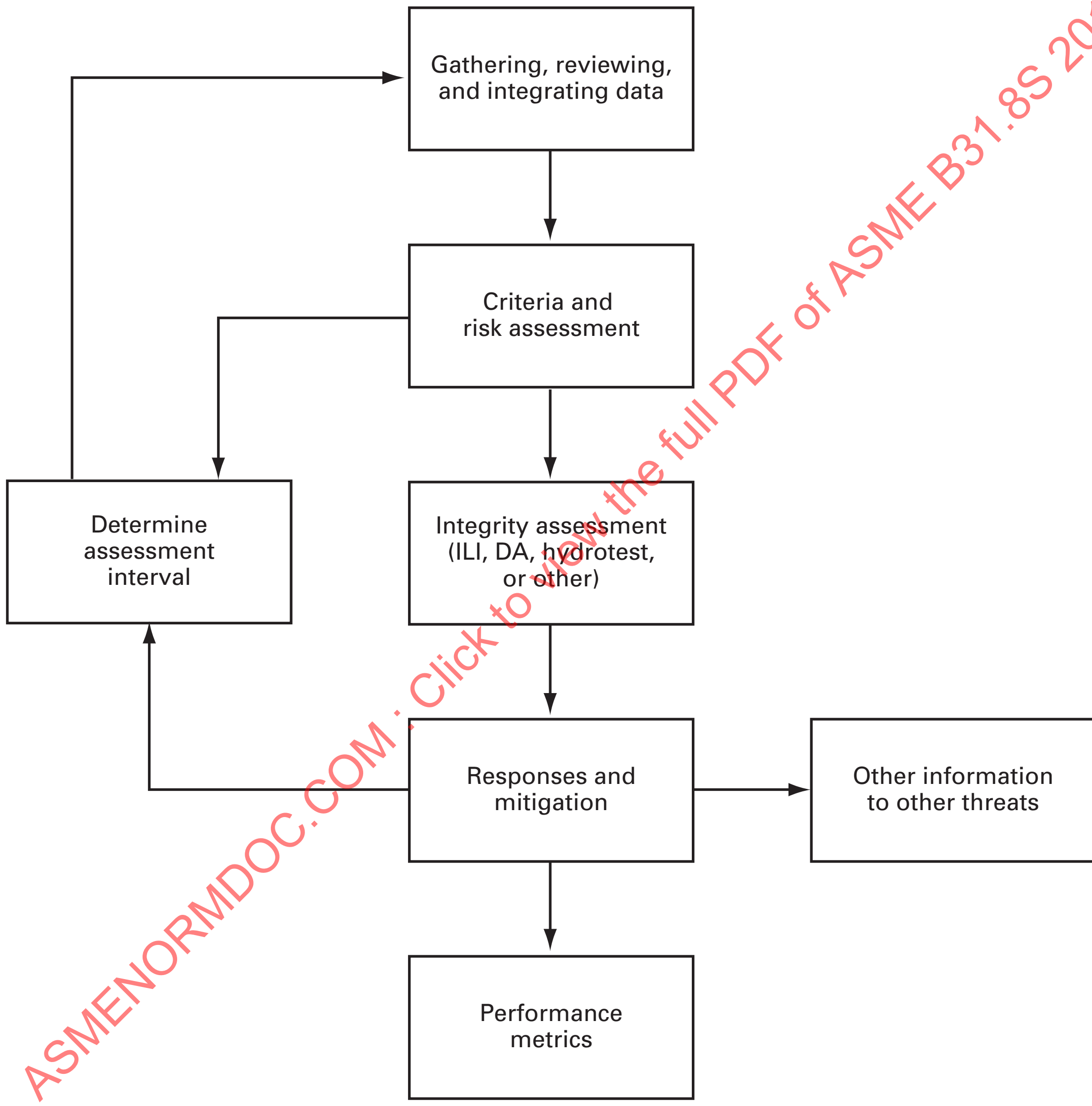
Section A-2 provides a general overview of the integrity management process for internal corrosion in general and also covers some specific issues. Pipeline incident analysis has identified internal corrosion among the causes of past incidents.

A-2.2 Gathering, Reviewing, and Integrating Data

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)

Fig. A-2.1-1 Integrity Management Plan, Internal Corrosion Threat (Simplified Process: Prescriptive)



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.

A-2.3 Criteria and Risk Assessment

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. 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 yr for pipe operating above 60% SMYS, 13 yr for pipe operating above 50% SMYS and at or below 60% SMYS, and 15 yr 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 para. A-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. The interval between the previous integrity assessment and the next integrity assessment cannot exceed the interval stated in this Code.

A-2.4 Integrity Assessment

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 section 6 of this Code, 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 section 6 of this Code, 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 section 6 of this Code, which defines the process, tools, and inspections. The operator selects the appropriate tools and he/she or his/her representative performs the inspections.

A-2.5 Responses and Mitigation

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 section 7 for responses to integrity assessments.

(b) Direct Assessment. The response is dependent on the number of indications examined, evaluated, and repaired. Refer to section 7 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 yr. If the test pressure was at least 1.25 times MAOP, the interval is 5 yr (see section 7).

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 section 7.

The operator shall select the appropriate prevention practices as outlined in section 7. 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.

A-2.6 Other Data

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.

A-2.7 Assessment Interval

The operator is required to assess integrity periodically. The interval for assessment is dependent on the responses taken, as outlined in para. A-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 section 11.

A-2.8 Performance Metrics

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)

A-3 STRESS CORROSION CRACKING THREAT

(12) ### A-3.1 Scope

Section A-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.

(12) ### A-3.2 Gathering, Reviewing, and Integrating Data

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.

A-3.3 Criteria and Threat Assessment (12)

A.3.3.1 Possible Threat of Near-Neutral pH SCC. (12) 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 yr.

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.

A-3.3.2 Possible Threat of High pH SCC. Each segment should be assessed for the possible threat of high pH SCC if the three criterias in para. A-3.3.1 are present and the following two criterias are also present: (12)

(a) operating temperature >100°F (38°C)

(b) distance from compressor station discharge ≤20 mi (32 km)

A-3.3.3 Additional Considerations. 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.

A-3.4 Integrity Assessment (12)

If conditions for SCC are present (i.e., meet the criteria in para. A-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.

Table A-3.4-1 SCC Crack Severity Criteria

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 paras. A-3.4.1 through A-3.4.4.

The severity of SCC indications is characterized by Table A-3.4-1. Several alternative fracture mechanics approaches exist for operators to use for crack severity assessment. The values in Table A-3.4-1 have been developed for typical pipeline attributes and representative SCC growth rates, using widely accepted fracture mechanics analysis methods.

(12) **A-3.4.1 Bell Hole Examination and Evaluation Method.** 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 Tables A-3.4-1 and A-3.4.1-1.

The response requirements applicable to the SCC crack severity categories are provided in Table A-3.4.1-1. The response requirements in Table A-3.4.1-1 incorporate conservative assumptions regarding remaining flaw sizes.

Alternatively, an engineering critical assessment may be conducted to evaluate the threat.

A-3.4.2 Hydrostatic Testing for SCC. 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:

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

(b) perform Engineering Assessment to evaluate (12)
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.

A-3.4.3 In-Line Inspection for SCC. Industry experience has indicated some successful use of in-line inspection (ILI) for SCC in gas pipelines. Refer to para. 7.2.2 for appropriate response to indications of SCC identified by in-line inspection. Table A-3.4-1 can be used to establish a reassessment interval for ILI, provided that the entire segment has been inspected. (12)

A-3.4.4 Stress Corrosion Cracking Direct Assessment (SCCDA). 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 (12)

(12) **Table A-3.4.1-1 Actions Following Discovery of SCC During Excavation**

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

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.

(12) A-3.5 Other Data

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.

A-3.6 Performance Measures

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

(12) *(b)* number of repairs or replacements due to SCC

(c) number of hydrostatic test failures due to SCC

A-4 MANUFACTURING THREAT (PIPE SEAM AND PIPE)

A-4.1 Scope

Section A-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 Fig. A-4.1-1).

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.

A-4.2 Gathering, Reviewing, and Integrating Data

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.

Fig. A-4.1-1 Integrity Management Plan, Manufacturing Threat
(Pipe Seam and Pipe; Simplified Process: Prescriptive)