Managing System Integrity for Hazardous Liquid Pipelines

API RECOMMENDED PRACTICE 1160
THIRD EDITION, FEBRUARY 2019
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Introduction

The goal of any pipeline operator is to operate the pipeline so that there are no adverse effects on the public, employees, the environment, or customers. The goal is an error-free, spill-free, and incident-free operation of the pipeline.

An integrity management program provides a way to improve the safety of pipeline systems and to allocate operator resources effectively to:

— identify and analyze actual and potential precursor events that can result in pipeline incidents,
— examine the likelihood and potential severity of pipeline incidents,
— provide a comprehensive and integrated method for examining and comparing the spectrum of risks and risk reduction activities available,
— provide a structured, easily-communicated way for selecting and implementing risk reduction activities,
— establish and track system performance with the goal of improving that performance.

This recommended practice (RP) outlines a process that an operator of a pipeline system can use to assess risks and make decisions about risks in operating a hazardous liquid pipeline to achieve a number of goals, including reducing both the number and consequences of incidents. Section 4 describes the components of an integrity management program. This RP also supports the development of integrity management programs required under 49 CFR 195.452 of the U.S. federal pipeline safety regulations.

This RP is intended for use by individuals and teams charged with planning, implementing, and improving a pipeline integrity management program. A team may include engineers, operating personnel, and technicians or specialists with specific experience or expertise (such as corrosion, in-line inspection, and right-of-way patrolling). Users of this RP should be familiar with applicable pipeline safety regulations (e.g. 49 CFR 195). This RP is also designed to serve as a roadmap to relevant consensus standards, recommended practices, guidance documents, technical reports, advisory bulletins, and safety regulations that can help operators manage integrity for hazardous liquid pipelines.

Guiding Principles

The development of this RP was based on certain guiding principles. These principles are reflected in multiple sections and are provided to give the reader the opportunity to view pipeline integrity from a broader perspective.

Integrity should be built into pipeline systems from initial planning, design, and construction. Integrity management of a pipeline starts with the sound design and construction of the pipeline. Guidance for new construction is provided in several consensus standards, including ASME B31.4, as well as pipeline safety regulations. As these standards and guidelines are applied to the design of a pipeline, the designer should consider the area the pipeline traverses and the possible impacts that the pipeline may have on that area, and the people that reside in its vicinity. New construction is not a subject of this RP, but the design specifications and as-built condition of the pipeline provide important baseline information for an integrity management program.

Effective integrity management is built on qualified people using defined processes to operate maintained facilities. The integrity of the physical facility is only part of the complete system that allows an operator to reduce both the number of incidents and the adverse effects of errors and incidents. The total system also includes the people that operate the facility and the work processes that the employees use and follow. A comprehensive integrity management program should address people, processes, and facilities.

An integrity management program should be flexible. An integrity management program should be customized to
An integrity management program should be flexible. An integrity management program should be customized to support each operator's unique conditions. Furthermore, the program should be continually evaluated and modified to accommodate changes in the pipeline design and operation, changes in the environment in which the system operates, and new operating data and other integrity-related information.

Continuous evaluation is required to ensure the program takes appropriate advantage of improved technology and that the program remains integrated with the operator's business practices, and effectively supports the operator's integrity goals.

The integration of information is a key component for managing system integrity. A key element of the integrity management program is the integration of all relevant information in the decision-making process. 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 integrating all of the relevant information, the operator can determine where the risks of an incident are applicable and are the greatest and make prudent decisions to reduce these risks.

Preparing for and conducting a risk assessment is a key element in managing pipeline system integrity. Risk assessment is an analytical process through which an operator determines the types of adverse events or conditions that might impact pipeline integrity, the likelihood that those events or conditions 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 and analysis of design, construction, operating, maintenance, testing, and other information about a pipeline system. Risk assessments can have varying scopes, varying levels of detail, and use different methods. The ultimate goal of assessing risks is to identify and prioritize the most significant risks so that an operator can make informed decisions about these issues.

Assessing risks to pipeline integrity is an iterative process. The operator continuously gathers new and refreshed information about the pipeline system through operating, maintenance, and testing experience. This information should be factored into the understanding of system risks. As the significance and relevance of this newer information to risk is understood, the operator may need to adjust its integrity plan accordingly. This may result in changes to inspection methods or frequency or additional modifications to the pipeline system in response to the data. As changes are made, different pipelines within a single operating company and different operators will be at different places with regard to the goal of incident-free operation. Each pipeline system and each company should implement specific goals and measures to monitor the improvements in integrity, and to assess the need for additional changes. The following applies to operators:

— Operators have multiple options available to address risks. Components of the facility or system can be changed; additional training can be provided to the people that operate the system; processes or procedures can be modified; or a combination of actions can be used to optimize risk reduction.

— Operators should address integrity issues raised from assessments and information analysis.

— Operators should evaluate anomalies and identify those that are potentially injurious to pipeline integrity.

— Operators should remediate or eliminate injurious defects.

— Operators should periodically assess the capabilities of new technologies and techniques that may provide improved understanding about the pipe’s condition or provide new opportunities to reduce risk. Knowledge about what is available and effective will allow the operator to apply the most appropriate technologies or techniques to a specific risk to best address potential impacts.

Pipeline system integrity and integrity management programs should be evaluated on a continual basis. Operators are encouraged to perform internal reviews to ensure the effectiveness of the integrity management program in achieving the program’s goals. Some operators may choose to use the services of third parties to assist with such evaluations.
Managing System Integrity for Hazardous Liquid Pipelines

1 Scope

This recommended practice (RP) is applicable to pipeline systems used to transport hazardous liquids as defined in U.S. Title 49 CFR Part 195.2. The use of this RP is not limited to pipelines regulated under 49 CFR 195 and the principles embodied in integrity management are applicable to all pipeline systems.

This RP is specifically designed to provide the operator with a description of industry-proven practices in pipeline integrity management.

The RP is largely targeted to onshore pipelines along the right-of-way, but the process and approach can be applied to pipeline facilities, including pipeline stations, terminals, and delivery facilities associated with pipeline systems. Certain sections of this RP provide guidance specific to pipeline stations, terminals, and delivery facilities.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Bulletin 5T1, Imperfection and Defect Terminology

API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction

API Recommended Practice 1110, Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide

API Standard 1163, In-line Inspection Systems Qualification

API Recommended Practice 1166, Excavation Monitoring and Observation for Damage Prevention

API Recommended Practice 1173, Pipeline Safety Management Systems

API Recommended Practice 1176, Assessment and Management of Cracking in Pipelines


ASME B31.4, Liquid and Slurry Piping Transportation Systems

ASME B31.8S, Managing System Integrity of Gas Pipelines

ASTM E1049-85, Standard Practices for Cycle Counting in Fatigue Analysis

NACE SP0169, Control of External Corrosion on Underground or Submerged Metallic Piping Systems

NACE SP0204, Stress Corrosion Cracking (SCC) Direct Assessment Methodology

NACE SP0502, Pipeline External Corrosion Direct Assessment Methodology
3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1 abandoned pipeline
Pipeline has been shut down, physically isolated from other in-service lines, connections to all sources of hazardous liquid or gas natural or other gas are isolated (capped or blinded), system purged of combustibles, sealed, and permanently removed from service. Some or all of the pipeline may have been physically removed.

NOTE See also decommissioned pipeline and idle pipeline.

3.1.2 actionable anomaly
An anomaly that may exceed acceptable limits based on the operator’s anomaly and pipeline data analysis; see API 1163.

3.1.3 active pipeline
A pipeline or pipeline segment being used to transport hazardous liquids in accordance with the provisions of the applicable code.

NOTE See also in-service pipeline.

3.1.4 anomaly
An unexamined deviation from the normal sound pipe material, coatings, or welds.

NOTE 1 See also flaw, defect, and imperfection.

NOTE 2 Also, an indication generated by nondestructive inspection; see NACE 35100.

3.1.5 cathodic protection
Technique by which metallic pipe is protected against external corrosion.

3.1.6 check valve
A valve that permits fluid to flow freely in only one direction and contains a mechanism to automatically prevent flow in the other direction.

3.1.7 critical location
Locations such as populated areas, commercially navigable waterways, drinking water resources, ecologically sensitive areas, and others as designated by the operator.

NOTE 1 See also high consequence area.

NOTE 2 Operators in the United States shall comply with 49 CFR 195 requirements for high consequence areas.
3.1.8 decommissioned pipeline
Pipeline has been shut down, physically isolated from other in-service lines, connections to all sources of hazardous liquid or gas natural or other gas are sealed (capped or blinded), system purged of combustibles, sealed, and removed from service. Decommissioned pipelines are generally not intended to be returned to service.

NOTE See also idle pipeline and abandoned pipeline.

3.1.9 defect
Imperfection of a type or magnitude exceeding acceptable criteria.

NOTE See also anomaly, flaw, and imperfection.

3.1.10 design pressure
Pressure defined by the yield strength, wall thickness, nominal outside diameter, and appropriate joint and design factors.

3.1.11 direct assessment
DA
Integrity assessment processes for detecting time-dependent degradation of a pipeline caused by external corrosion, internal corrosion, or stress corrosion cracking that involve making certain measurements, conducting certain analyses, and excavating the pipeline where appropriate to examine its condition.

NOTE See also external corrosion direct assessment, internal corrosion direct assessment, and stress corrosion cracking direct assessment.

3.1.12 double submerged arc welded pipe
DSA W pipe
Pipe that has a straight longitudinal or helical seam containing filler metal deposited on both sides of the joint by the submerged-arc process.

3.1.13 electric resistance welded pipe
ERW pipe
Pipe that has a straight longitudinal seam produced without the addition of filler metal by the application of mechanical force and heat obtained from electric resistance.

3.1.14 emergency flow restriction device
EFRD
A valve that restricts fluid flow to only one flow direction or can be closed from a location remote from where the valve is installed.

NOTE See check valve or remote control valve.

3.1.15 environmentally assisted cracking
EAC
Corrosive attack of the pipe metal caused by exposure to specific environments either internal or external to the pipe and resulting in any of several forms of metal cracking. EAC includes, but is not limited to, hydrogen-induced cracking.
(HIC), stress-oriented hydrogen-induced cracking (SOHIC), sulfide-stress cracking (SSC), or stress corrosion cracking (SCC).

3.1.16  
**estimated rupture pressure**
ERP
Failure pressure, estimated using an appropriate fitness for service calculation without a factor of safety.

3.1.17  
**external corrosion direct assessment**
An integrity assessment process for locating possible external corrosion, damaged coating, or deficiencies in cathodic protection on a pipeline by making above-ground measurements and following up with excavations to examine the pipe where appropriate; see NACE SP0502.

3.1.18  
**failure pressure ratio**
FPR
Ratio of the ERP to the maximum pressure expected during service, i.e. the ratio of the calculated failure pressure of an anomaly to the maximum operating pressure (MOP) at the location of the anomaly, i.e. \( FPR = \frac{ERP}{MOP} \).

3.1.19  
**Fatigue (cited in API RP 1176)**
Process of forming or enlarging a defect or flaw due to cycles of stress.

3.1.20  
**flaw**
An imperfection that is smaller than the maximum allowable size.

NOTE  See also anomaly, defect, and imperfection.

3.1.21  
**guided wave ultrasonic testing**
GWUT
A technique for detecting anomalies in a pipeline that involves introducing mechanical stress waves that propagate axially from a circumferential array of low-frequency transducers placed around the pipeline at a fixed location.

NOTE 1  The wall thickness of the pipe serves as a wave guide, and the locations of anomalies are established by the timing of the arrival of a wave reflected from the anomaly back to the location of the emitting device.

NOTE 2  The technique is applicable for distances up to several hundred feet depending on site specific conditions such as bends, coating type, weld spacing or other factors.

3.1.22  
**heat-affected zone**
HAZ
The portion of the base metal that was not melted during brazing, cutting, or welding, but whose microstructure and properties were affected by the heat of these processes.

3.1.23  
**hard spot**
Area in the pipe with a hardness level considerably higher than that of the surrounding metal, usually due to localized quenching or alloy segregation.
3.1.24  
**high consequence area**  
**HCA**  
Those locations where a pipeline release might have a significant adverse effect on an unusually sensitive area, a high population area, another populated area, or a commercially navigable waterway.

**NOTE 1** This definition is specific to the federal regulations in the United States, see 49 CFR 195.

**NOTE 2** An unusually sensitive area is a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

3.1.25  
**high pressure test**  
A test undertaken at pressures potentially greater than necessary for qualifying a pipeline for service under regulations in order to address or assess for an identified or targeted pipeline threat.

**NOTE** Similar to a “spike” test, an alternative when spike testing may not be advised or warranted.

3.1.26  
**highly volatile liquid**  
A hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 40 psia (276 kPa) at 100 °F (37.8 °C).

3.1.27  
**hydrogen-induced cracking**  
**stepwise cracking**  
**HIC**  
Cracking that may occur in line pipe steels containing manganese sulfide inclusions exposed to atomic hydrogen generated at the surface of the pipe externally by a cathodic reaction or internally by a corrosion reaction of sour products and water.

3.1.28  
**hydrogen stress cracking**  
A form of cracking that may occur in localized hard spots or hard heat-affected zones in a line pipe steel if those zones are exposed to atomic hydrogen.

3.1.29  
**hydrostatic test**  
Means of assessing the integrity of a new or existing pipeline that involves filling the pipeline with water and pressurizing to a level significantly in excess of the MOP for an appropriate duration to confirm no leaks are present and to demonstrate that the pipeline is fit for service at the MOP.

**NOTE** See API RP 1110.

3.1.30  
**idle pipeline**  
Pipeline has been shut down, physically isolated from all sources of hazardous liquid or gas (natural or other gas (capped or blinded), system purged of combustibles or maintain a blanket of natural gas at pressure and removed from service. An idled line may be returned to active service. Certain inspection and maintenance activities may be suspended.

3.1.31  
**imperfection**  
A flaw or other discontinuity noted during inspection that passes acceptance criteria during an engineering and inspection analysis.
NOTE See also anomaly, defect, and flaw.

3.1.32
indication
A discovery from nondestructive testing (NDT), inspection technique, or signal from an ILI system.

3.1.33
in-line inspection
ILI
Inspection of a pipeline from the interior of the pipe using an inspection tool.

NOTE 1 This is also called intelligent or smart pigging.

NOTE 2 This includes free swimming, tethered, and self-propelled inspection tools.

3.1.34
in-service pipeline
active pipeline
A pipeline or pipeline segment that currently transports hazardous liquids.

3.1.35
integrity assessment
Method for determining the pipe’s condition.

NOTE Methods can include ILI, pressure testing, direct assessment, or other technologies that can demonstrate the integrity of the pipe.

3.1.36
internal corrosion direct assessment
ICDA
Integrity assessment process conducted for the purpose of locating and remediating anomalies arising from internal corrosion of a pipeline.

NOTE See NACE SP0208 (LP-ICDA standard for liquid petroleum), NACE SP0206 (DG-ICDA standard for dry gas), and NACE SP0110 (WG-ICDA standard for wet gas).

3.1.37
maximum operating pressure
MOP
Maximum pressure at which a liquid pipeline system may be operated in accordance with the provisions of the applicable code.

3.1.38
mill test pressure
The test pressure applied in the pipe mill as part of the original pipe manufacturing process.

3.1.39
mitigation
mitigative action
Taking appropriate action based on an assessment of risk factors to reduce the overall level of pipeline integrity risk by reducing the amount of risk from a probability or consequence standpoint.

3.1.40
operator
Entity that operates pipeline facilities.
3.1.41 piping circuit
A section of piping that has all points exposed to an environment of similar threat state and that is of similar design conditions and construction material.

3.1.42 preventive and mitigative measures
Activities designed to reduce the likelihood of a pipeline failure (preventive) and/or minimize or eliminate the consequences of a pipeline failure (mitigative).

3.1.43 remediation
Taking action to remove one or more causes of pipeline risk or to neutralize the potentially adverse effects of an injurious anomaly consisting of, but not limited to, further testing and evaluation, changes to the physical environment, operational changes, continued monitoring, administrative/procedural changes, and repairs of defects.

3.1.44 remote control valve
Any valve that is operated from a location remote from where the valve is installed.

NOTE A remote control valve is usually operated by the supervisory control and data acquisition (SCADA) system.

3.1.45 risk
Measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

3.1.46 risk assessment
Systematic, analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined.

3.1.47 risk management
An 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.

3.1.48 selective seam weld corrosion
SSWC
Form of external or internal corrosion attack that occurs preferentially along the weld bond line of ERW or FW line pipe that often has the appearance of a wedge-shaped groove when conditions exist that cause the bond line region or the ERW or FW seam to corrode at a faster rate than the surrounding base metal.

3.1.49 spike hydrostatic test
Short-duration hydrostatic test wherein the pressure level is higher than the strength test, the purpose of which is to achieve an increased level of confidence in the serviceability of the pipeline or an increased interval until the next assessment.

NOTE Similar to high pressure testing.
3.1.50  
stand-up (operational) test  
A pressure test to determine the leak tightness of a pipeline or pipeline segment, typically conducted with product or water at a pressure significantly less than hydrostatic test pressure and does not exceed the MOP of the pipe.

NOTE   A pipeline company may conduct this test after a pipeline is constructed but prior to beginning shipment of product delivery.

3.1.51  
stress corrosion cracking direct assessment  
SCCDA  
Direct assessment conducted for the purpose of locating and remediating anomalies arising from stress corrosion cracking (SCC) of a pipeline or evaluating whether SCC is a threat on a particular pipeline.

NOTE   See NACE SP0204.

3.1.52  
stress riser  
a scrape, gouge, groove, notch, or metal loss unrelated to corrosion.

3.1.53  
surge pressure (transient pressure)  
Pressure produced by a change in the velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

3.1.54  
transit fatigue  
Development of longitudinal fatigue cracks in line pipe as the result of transportation by rail car, truck, or marine vessel.

3.2  
Acronyms and Abbreviations

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4 Integrity Management Program

4.1 Program Considerations

4.1.1 Integrity Management Program Components

A pipeline integrity management program is a documented set of policies, processes, and procedures to manage pipeline risk. The program should begin with threat identification and then facilitate appropriate and timely actions on the part of a pipeline operator to ensure that a pipeline system is continually operated in a manner that manages risk to the public, employees, the environment, and customers. In addition to traditional integrity management activities related to assessment, inspection, and maintenance of the pipeline system, a comprehensive pipeline integrity management program should also include activities that assess and improve the performance of the program itself. The program elements that should be included in an integrity management program are depicted in Figure 1 and discussed in detail in Section 4.2.
To address pipeline risk changing over time, a pipeline operator must continue to assess its pipelines at specified intervals and periodically evaluate the integrity of its pipelines. A pipeline operator ensures these periodic reassessments are effective through a continuous cycle of monitoring pipeline condition, identifying and assessing risks, and taking action to reduce the most significant risks. Risk assessments should be periodically updated and revised to reflect current conditions so operators can most effectively use their finite resources to achieve the goal of error-free, spill-free operation.

4.1.2 Continuous Integrity Management Improvement with a Pipeline Safety Management System

Figure 1 illustrates one example of the continuous cycle of a pipeline integrity management program. Figure 1 also reflects the way this continuous cycle aligns with the Plan-Do-Check-Act (PDCA) cycle of a pipeline safety management system (pipeline SMS). Discussed in greater detail in API RP 1173, Pipeline Safety Management Systems, a pipeline SMS provides a mechanism for enhanced risk assessment and continuous pipeline safety performance improvement. While API RP 1173 is a flexible and scalable framework, its core principles of learning from experience, continuous improvement, and awareness and management of many linked activities will improve the effectiveness of a pipeline integrity management program. To emphasize these benefits, the elements of an integrity management program discussed in Section 4.2 are organized by their occurrence in the PDCA cycle of a pipeline SMS. Programs may evolve and mature over time. The PDCA elements depicted in Figure 1 also apply to facility integrity management programs which are discussed in Section 12.

In addition to organizing integrity management program activities in a continuous PDCA improvement loop, application of individual elements of API RP 1173 will enhance the effectiveness of integrity management program activities. Examples include the following:

— Supporting integrity management resource needs and commercial trade-offs
  — Leadership and Management Commitment (API RP 1173, Section 5)

— Influencing pipeline integrity risk assessment
  — Stakeholder Engagement (API RP 1173, Section 6)
  — Risk Management (API RP 1173, Section 7)
  — Operational Controls (API RP 1173, Section 8)
  — Management of Change (API RP 1173, Section 8.3)

— Benefit pipeline integrity assessment and program evaluation activities
  — Incident Investigation, Evaluation and Lessons Learned (API RP 1173, Section 9)
  — Safety Assurance (API RP 1173, Section 10)
  — Management Review and Continuous Improvement (API RP 1173, Section 11)

A further concept for operators to consider is applying the PDCA cycle to individual integrity management activities. Just as the activities of the integrity management program may be arrayed around the PDCA cycle as illustrated in Figure 1, each of those activities may have their own PDCA cycle of tasks. For example, the activity of Conduct Pipeline Inspections, Testing, and Examinations is positioned in Figure 1 in the “Do” stage of the cycle. Conducting pipeline inspections also involves planning the inspections, performing the inspections, tasks to verify the inspections, and potential improvement tasks for the next round of inspections. Organizing individual tasks formally by PDCA stage is up to the operator, but the model may prove useful for some operators.
4.2 Elements of Integrity Management

Integrity management program elements accomplish the threat management goals of the program through both direct pipeline integrity-related activities as well as supporting activities to improve the quality of the program itself. In pipeline SMS terms, a successful integrity management program includes integrity management “Plan and Do” assessment, inspection and maintenance activities, “Check and Act” performance measuring, evaluation, and improvement activities.

4.2.1 “Plan” Integrity Management Elements

(1) Gather Data to Identify Integrity Threats—To understand the potential threats to the integrity of a pipeline segment an operator should gather, review, and integrate the relevant and available information. Such information generally consists of the design of the pipeline, the attributes of the pipeline, the operational history including operating pressure ranges and past releases if any, the results of prior inspections and assessments including any in-line inspections (ILIs) or hydrostatic tests, previously made repairs or other mitigative responses, corrosion and cathodic protection surveys, and measures taken to prevent releases or the effects of a release. In addition, as the system continues to be operated, the accumulated operating, maintenance, and surveillance data should be collected for
input into the next scheduled re-evaluation of risk prior to the next integrity assessment. Section 5 provides an overview of hazardous liquid pipeline threats and Annex A provides a detailed description of each threat. Section 7 provides a summary of the data sources, common data elements that are typically used in risk analyses, and approaches to data review and integration.

(2) Identify Potential Pipeline Impacts to Critical Locations—This program element involves the identification of pipeline segments that may affect critical locations in the event of a release. Identification of critical locations involves evaluating populated, environmentally sensitive, and navigable water area information, integrating this information with pipeline mapping data, and determining at which locations a release may impact these areas. The identified critical locations may change with time or with changes to the pipeline system. Therefore, critical locations need to be reviewed and updated on a regular basis. Guidance for making these determinations is provided in Section 6 of this RP.

(3) Assess Risk and Rank Segments—Data assembled from the previous steps are used to conduct a risk assessment of the pipeline system. Risk reassessments should be performed at established intervals to factor in recent operating data and to consider changes to the pipeline system design (e.g. new valves, newly replaced pipeline segments, or rehabilitation projects) and operation (e.g. a change in flow or the hydraulic pressure profile). Changes in population, changes altering segments that can affect critical locations, the results of previous integrity assessments, and the impacts of repairs and mitigative measures should also be taken into account in these risk reassessments. The goal should be to ensure that the analytical process reflects the latest understanding of pipe condition. Section 8 provides guidance for developing and implementing a risk assessment approach.

(4) Develop or Revise a Pipeline Integrity Assessment Plan—The pipeline operator should develop a plan to assess the integrity of the pipeline system, or modify as appropriate, an existing plan that has been followed previously. The pipeline operator's plan should identify the internal inspection technique(s), pressure testing, or other technology that will be used to assess the integrity of the pipeline. It should also establish the schedule for conducting these assessments, the justification for the integrity assessment method(s) selected, and mitigative measures that will be employed. Section 9 provides guidance for conducting integrity assessments, and Annex B provides a description of the various internal inspection techniques available and guidance to assist operators in selecting an integrity assessment method.

4.2.2 “Do” Integrity Management Elements

(5) Conduct Pipeline Inspections, Testing, and Examinations—The pipeline operator should implement the in-line inspection (ILI), hydrostatic pressure testing, or direct assessment described in the pipeline integrity assessment plan. The specific type of inspection, testing, or examination undertaken will reflect the most appropriate method for addressing the threat and risks identified in the integrity assessment plan. Section 9 provides guidance for conducting integrity assessments and Annex B provides a description of available internal inspection techniques.

(6) Integrate Integrity Assessment Data—The pipeline operator should collect data on the integrity of its pipeline, including data generated by integrity inspections, testing, and examination. The pipeline operator should gather data in a timely manner, including results and reports generated by inspection vendors. The pipeline operator should pay particular attention to regulatory or other recommended timeframes within which to obtain results from inspection vendors.

In addition to data on its pipelines, the operator should also collect data on its inspection, testing, and examination methods. The pipeline operator will use this inspection tool and method data to analyze the effectiveness of its inspection tools and integrity program. Data on in-line inspections should be collected to compare to integrity excavations and non-destructive examination results to assess the effectiveness of each inspection tool or examination method. Section 7 provides a summary of the data sources, common data elements, and approaches to data review and integration.

(7) Collect Program Performance Data—The pipeline operator should collect program performance metrics that indicate the effectiveness of its integrity management program. The operator should collect measures of the quality of
its threat assessment, critical location selection, risk assessment, assessment planning, inspection, integrity assessment, remediation activities, preventive and mitigative activities, reassessment intervals, and program improvement. Section 13 provides guidance for developing performance measures to evaluate program effectiveness and for conducting audits of integrity management programs.

4.2.3 “Check” Integrity Management Elements

(8) Review Management of Change (MOC) Measures—Pipeline systems and the environments in which they operate are not static. A systematic process should be used to ensure that changes to the pipeline system design, operation, or maintenance are evaluated for their potential risk impacts prior to implementation and to ensure that changes in the environment in which the pipeline operates are documented and evaluated. Furthermore, after these changes have been made, they should be incorporated, as appropriate, into future risk assessments to be sure the risk assessment process addresses the system as it is currently configured, operated, and maintained. Section 14 discusses the important aspects of MOC as it relates to integrity management.

(9) Integrate Pipeline, Tool, and Program Performance Data Together with MOC Information—The pipeline operator should integrate data from pipeline inspections, testing and examination, data on inspection tool performance, and MOC information. Each of these data sources analyzed individually may produce an incomplete picture of the integrity of a specific pipeline segment. Data integration will allow the operator to understand the cumulative impact of each threat factor reflected by multiple data sources when evaluating pipeline integrity.

Operators should ensure that policies, processes, procedures, and records are in place to provide integrity management program managers with the multiple streams and sources of data and information they need to review and integrate. Depending upon the specific organizational or authority structure of an operator, sources of data or information needed for pipeline integrity management may be generated or stored outside the purview of integrity managers. Established policies, processes, and procedures will ensure necessary data and information is generated and delivered into the integrity management program in alignment with the program’s PDCA cycle. Section 7 provides guidance on data maintenance and management of change.

(10) Review Operator, Industry, and Regulator Learnings, and Recommendations—An operator should also gather, review, and integrate applicable industry trends, regulatory notices, and other operators’ experiences where applicable. Pipeline safety information and lessons learned shared by pipeline operators through industry groups and forums may relate to a specific risk or threat faced by a pipeline operator. Recommendations or reports issued by investigators after incidents, as well as advisory bulletins issued by regulators, may also contain information beneficial to pipeline integrity. Many of the products produced for the Management Review and Continuous Improvement element of a pipeline SMS, discussed in Chapter 11 of API RP 1173, will benefit pipeline integrity management including results of risk management review, results and recommendations of incident investigations, evaluations and lessons learned, results of internal and external audits, and evaluations and stakeholder feedback. Section 13 discusses performance tracking and trending to facilitate continuous improvement efforts.

(11) Evaluate Integrity Program Performance—Reviews need to be performed on a periodic basis to evaluate the effectiveness of a pipeline operator's integrity management program. The operator should review program performance metrics and periodically evaluate the effectiveness of its integrity assessment methods and its preventive and mitigative risk control activities, including repair. The operator should also evaluate the effectiveness of its management systems and processes in supporting integrity management decisions. A combination of performance measures and system self-reviews is necessary to evaluate the overall effectiveness of a pipeline integrity management program. Section 13.4 describes integrity management program issues recommended for review and evaluation. Results of this evaluation may also feed into a Management Review conducted as part of an operator's pipeline SMS.

(12) Assess Pipeline Integrity—The pipeline operator should assess the integrity of its pipeline segments based on an evaluation and consideration of the results of its integrated data. As discussed above, pipeline inspection results, data on inspection tool performance, and MOC information are all necessary to develop a comprehensive assessment of a pipeline’s integrity. Pipeline operators should also incorporate into integrity assessments any applicable operator,
industry, or regulator lessons, recommendations, or advisories. For pipeline segments that may affect critical locations, the operator should establish reasonable and technically justifiable time limits for the examination of several classes of anomalies detected by ILI. This schedule should consider applicable regulatory statutes. Section 9.2 provides guidance for prioritizing features identified by ILI for examination and repair. Annex C provides a description of commonly used repair techniques to address the different types of defects that might be discovered during integrity assessment.

4.2.4 “Act” Integrity Management Elements

(13) Perform Pipeline Remediation Activities—The pipeline operator should implement appropriate remediation activities based on its pipeline integrity assessment(s). Specific remediation activities should address the threats to the pipeline segment and the risk represented by those threats. Section 9.2 describes strategies for responding to anomalies identified by pipeline inspection, testing, or examination, including conditions requiring immediate or scheduled response.

(14) Perform Pipeline Preventive and Mitigative Activities—A pipeline operator should establish and implement a process to evaluate the need for additional measures to reduce pipeline risk. The following list provides some examples of potential measures:

— Preventing mechanical damage. Generally, this involves participating in one-call systems, locating and marking a pipeline segment when excavation is to take place on the right-of-way, monitoring contractors working on the right-of-way, establishing and maintaining a public awareness program, maintaining visible right-of-ways, and conducting periodic aerial or ground surveillance of the right-of-ways.

— Establishing and maintaining a corrosion mitigation program.

— Installing emergency flow restriction devices (EFRDs) at appropriate locations.

— Developing emergency response plans to limit the amounts of unrecovered product in the event of a release.

Additional preventive and mitigative measures are described in Section 11.

(15) Calculate Pipeline Reassessment Intervals—The pipeline operator should conduct integrity reassessments on a periodic basis. The pipeline operator should develop a schedule for reassessments that considers items such as the rates of deterioration, the consequences of an event, and other risk factors. Section 10 provides guidelines for scheduling reassessments. Examples of how one might go about calculating reassessment intervals are presented in Annex D.

(16) Undertake Integrity Program Improvement—The operator should use the results of the program performance evaluation to modify the integrity management program as part of a continuous improvement process. Recommendations for changes or improvements, or both, should be based on analysis of the performance measures and the audits. All recommendations for changes or improvements, or both, should be documented, and the recommendations should be implemented in the next cycle of integrity assessment. Section 13 provides guidance for developing performance measures to evaluate program effectiveness and Section 14 discusses the important aspects of MOC related to integrity management.

5 Threat Assessment

5.1 Threats

Integrity management begins with a systematic and comprehensive consideration of potential threats to the integrity of the pipeline or facility. The threats for hazardous liquid pipelines that operators should consider are as follows:

a) external corrosion;
b) internal corrosion;

c) selective seam weld corrosion (SSWC), external or internal;

d) environmentally assisted cracking (EAC) including stress corrosion cracking (SCC), hydrogen-induced cracking (HIC), stress-oriented hydrogen-induced cracking (SOHIC), and sulfide-stress cracking (SSC);

e) manufacturing defects including defective pipe seams, hard heat-affected zones (HAZ), and defective pipe including pipe body hard spots;

f) construction and fabrication defects including defective girth welds, defective fabrication welds, wrinkle bends, and stripped threads/broken pipe/coupling failures;

g) equipment failure including gasket or o-ring failure, control or relief equipment failure, seal or pump packing failure, and miscellaneous;

h) mechanical damage caused by accident, negligence or deliberate act of vandalism;

i) incorrect operations; and

j) weather and outside forces including cold weather, lightning, heavy rains or floods, or earth movements, or a combination thereof, which may cause wrinkles, buckles, cracked valve bodies, and girth weld cracks.

An operator shall review data for each pipeline segment or facility to determine which of these threats are credible and need to be addressed.

It is recognized that not all 10 threats may apply to every hazardous liquid pipeline and that pipeline operators may want to customize their approach to considering these threats. These 10 threats are discussed in detail in Annex A. Any of these threats may have a time-delayed or interactive component to them. While fatigue by itself is not a threat, it can facilitate crack initiation and growth from an extant defect.

Failure of dents through environmental cracking, and delayed failure of mechanical damage are considered interactive threats and are discussed in 5.2.

5.2 Threat Interaction

A review of industry failure databases has shown that threats can interact and combine to create a more severe situation than the individual threats alone. Identifying threats and their interactions is performed by overlaying, comparing, and integrating relevant data sets for the pipeline, including pipeline attributes, construction factors, operating parameters and history, integrity assessment history, maintenance and repair history, and incident data. The processes and considerations relevant to the integration of the data are discussed in Section 7. Additional information can be found in API Bulletin 1178.

Examples of specific threat interactions can be broadly categorized by the following:

— corrosion (external or internal) with manufacturing defects like defective pipe seams, EAC (typically SCC) or SSWC;

— mechanical damage that contains stress concentrators (gouges, grooves, arc burns, or cracks) or corroded areas;

— localized loading from weather and outside force events that would impact an anomaly’s probability of failure;

— incorrect operations (e.g. valve closure leading to overpressure) affecting existing anomalies.
An additional reference is provided in the PHMSA Report Task III.B.2 Report DTPH56-14-H-00004, *Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats*. Inspection considerations for coincidental or interacting threats are provided in Annex B.8.

5.2.1 EAC and Manufacturing Defects Interacting with External or Internal Corrosion

The presence of external or internal corrosion in the same area as a cracking threat, either EAC (typically SCC), SSWC, or manufacturing defects (longitudinal seam weld anomalies) can create challenges for assessment methods. External or Internal corrosion can obscure the crack response for some ILI technologies and affect the depth measurement accuracy. Manufacturing defects interacting with external or internal corrosion can result in a narrow axially-oriented defect (more commonly known as SSWC) that is not easily detected or characterized with conventional metal loss ILI tools. The growth rate for SSWC, based on failure analysis experience, is typically two to four times the rate of growth in the base metal. This condition can lead to rapid development of a critically sized flaw in a defective seam bondline and has the potential to cause a rupture at low operating stress levels.

5.2.2 Mechanical Damage Interacting with External Corrosion or Cracking

Mechanical damage often damages the pipeline coating and creates a local stress in the pipeline which makes it more susceptible to external corrosion or EAC at the location of the damage. Threat interaction with external corrosion can occur where the indentation is sufficient to damage the coating and the cathodic protection is locally impaired. The increase in residual stress associated with the indentation or gouge can also be sufficient to initiate and grow cracks at this location.

Plain indentations less than six percent of the pipe diameter do not immediately reduce the strength of the pipe. Section 6.4.2 of API RP 1176 describes certain deformation geometries and susceptible environments that may potentially result in cracking and eventual failure (generally occurring as a leak) of an indentation. Factors that may lead to cracking include, but are not limited to, diameter to wall thickness \( \frac{D}{t} \) ratio (with a ratio of 100 and higher being more prone to cracking), pressure cycle severity, indentation shape, and physical restraint of the indentation. Data evaluation and opportunistic excavations may enable an operator to identify where cracking in plain indentations may be a threat.

There is significant and ongoing research being done in this field, including by the Pipeline Research Council International, which was not available at the time of this writing.

5.2.3 Equipment, Construction and Fabrication Defects Interacting with Weather and Outside Force

Weather events, such as heavy rains and floods, can produce scouring of backfill, mudslides, floatation of a pipeline, and vortex shedding in water current. The resulting lateral forces can cause pipes to pull out of mechanical couplings, threaded pipe or fittings to break, and pipelines to fail at the girth weld. The bending moments associated with the weather and outside force loading events can contribute to the severity (i.e. the non-dormancy) of flaws in the girth welds. Given that these features are less sensitive to the internal pressure due to their circumferential orientation, they may fail from secondary loads where the hoop stress is well below the maximum allowable. Using ILI technology to detect girth weld anomalies as described in API RP 1176 and inertial mapping can help assess these interacting threats.

Cold weather can also produce threat interactions with equipment, specifically associated with water freezing inside a pipe or component. Water can expand within a component causing it to fail, flow restrictions or blockages can lead to a pressure excursion, or ice falling from a roof can break small diameter threaded connections.

5.2.4 Incorrect Operations Interacting with Other Threats

Incorrect operations can interact with the other nine threats through overpressure events causing failure of flaws that are not of a critical size during normal operation. Improperly installed equipment or misaligned valves can result in accelerated fatigue of welds, components, or the pipe body.
5.2.5 Time Dependent Interactions

Operational or environmental conditions can act on resident features in the pipeline to cause degradation over time. Examples include the threat of cracks forming and growing due to fatigue from pressure and temperature cycles or vortex-induced or mechanical vibrations. An additional example is the effects of hydrogen that can arise from cathodic protection (CP) systems or sour crude systems. The operator shall assess for the conditions that can lead to time dependent degradation. Section 10 provides guidance to determine appropriate reassessment intervals.

6 Identifying Critical Locations with Respect to the Consequences of a Release

6.1 General

Because the main goal of pipeline integrity management is to reduce risk to the public, employees, the environment, and the customers, a pipeline operator should place a high priority on the inspection, evaluation, and maintenance of pipeline segments in areas where the consequences of a spill would be most likely to affect a critical location. For operators in the United States, a critical location may be identified as a high consequence area (HCA) and therefore the requirements in 49 CFR 195.452 shall be followed. Note that commercial software including geographic information system (GIS) technology is available to perform many of the tasks described in the following sections. This technology is available from numerous service providers. Information about pipeline segments and facilities that may affect critical locations is used in several key elements of an integrity management program, such as:

- data gathering;
- risk assessment;
- inspection and mitigation;
- decisions on placement of EFRDs;
- installation and use of leak detection systems;
- preventive and mitigative measures;
- development and implementation of spill response plans.

6.2 Determining Whether a Release from a Pipeline Segment or a Facility Could Affect a Critical Location

6.2.1 General

As part of the process of data gathering and integration of information into a pipeline integrity management program (IMP), a pipeline operator should determine if there is a reasonable likelihood that a particular pipeline segment or facility (e.g. pump station, delivery terminal) could affect a critical location in the event of a release. Operators should consider critical locations that are in proximity to the segment or facility as well as those that the pipeline segment actually crosses. Below is a list of items for consideration when determining a potential consequence:

a) the proximity of the pipe to identified critical locations;

b) the nature and characteristics of the product or products transported (such as refined products, crude oil, and highly volatile liquids [HVLs]);

c) the operating conditions of the pipeline (such as pressure, temperature, and flow rate);
d) the topography of the land associated with the critical location and the pipeline segment;

e) the hydraulic gradient of the pipeline;

f) the diameter of the pipeline, the potential release volume (including drain out), and the distance between isolation points;

g) the type and characteristics of the critical location crossed or in proximity to the segment;

h) potential physical pathways between the pipeline and the critical location, including overland spread, water transport including drainage systems, or air dispersion in the case of an HVL;

i) response capability (such as time to detect, confirm, and locate a release; time to respond; and nature of the response).

An outline of the process is shown in Figure 2.

6.2.2 Determining Critical Location Boundaries

The boundary of each critical location should be defined taking into account the amount of product that could be released, the means by which the product could spread, and the potential for personal injuries or property damage associated with a spreading plume of product in the soil, air dispersion of an HVL, pooling or spreading of liquid on the surface, or ignition causing a fire or explosion. Allowance should be made for any possible inaccuracies of the locations of the boundaries.

6.2.3 Identifying Segments or Facilities Located Within Critical Locations

By comparing a map of the pipeline's route to an appropriate map of the critical location, the operator should establish the points where the segment enters and leaves the critical location. Any facility lying within the boundaries of a critical location should be noted as well. This process will identify the segments or facilities where a release will directly affect the critical location.

6.2.4 Identifying Segments or Facilities That Could Affect a Critical Location When Such Segments or Facilities Are Not Located Within the Boundaries of the Critical Location

It should be recognized that a release from a pipeline segment or a facility could affect a critical location even if the segment or the facility is not within the boundaries of the critical location. To identify such segments or facilities, the operator should determine the extent to which released product or the effects of the release can be transported to the critical location. For example, the operator should consider that released product could be transported by overland spread, by water, or by aerial dispersion of a vapor cloud, and that the effects of ignition or explosion could be widespread. Operators may also consider that released product could be transported by spraying of product into the air.

Using topographical maps, maps of populated areas, and knowledge possessed or acquired by the operator’s personnel in the area, the operator should consider scenarios for released product being transported to a critical location. Each scenario should be based on postulating a release from a point along the pipeline segment or from key points such as breakout tanks within a facility. Successive release points along a pipeline segment at some reasonable spacing should be considered. Any point where the release scenario evaluation(s) indicates product reaching a critical location should be identified as one that could affect the critical location. Similarly, the operator should identify each facility as one that could affect a critical location if the release scenario for any key point within that facility results in product being transported to the critical location.
Factors for consideration in establishing release scenarios include the following:

— Release Volume—pipeline diameter, elevation profile, flow rate, time for detection, time to isolate, viscosity and vapor pressure of the product, and tank volume for tanks at facilities;

— Surface Transport—topography, terrain, extremes in ambient temperature, water pathways (surface and underground), ditches, sewers and drain tiles, porosity, and soil permeability;

— Aerial Dispersion—internal pressure and its effect on spraying product into the air, wind direction, analysis HVL (vapor cloud, effect that a vapor cloud fire, a pool fire, or a vapor cloud explosion would have on the critical location).
6.3 Documentation and Updating

The operator should document all pipeline segments and facilities that could affect critical locations. Supporting analyses should be made available to subject matter experts (SMEs) or others who will conduct risk assessments and for prioritizing integrity assessments. Periodically, the operator should conduct a review to see if any changes in segments or facilities that could affect critical locations have occurred. Alternatively, the operator may establish a process to identify changes during the conduct of typical operations and maintenance activities (e.g. aerial patrols, locate requests, management of change, right-of-way maintenance). Any new segments or facilities so identified should be added to the list of segments and facilities that could affect critical locations.

7 Data Integration

7.1 General

This section provides an overview of considerations, processes, and data elements involved in data integration to identify and manage the integrity threats on a pipeline system. The approach described herein recognizes that users of this RP will have numerous data sources on their pipeline systems managed through existing processes. These data may need to be gathered and organized differently for integrity management purposes.

Data integration generally refers to the process of utilizing two or more data sets to identify conditions of interest on the pipeline. API Bulletin 1178 provides detailed information on methodologies and considerations to integrating the underlying data used to support integrity management. Examples of data sets are provided in 7.3. In more advanced applications, the data integration process may include computer applications that spatially align and correlate the available data along the pipeline.

Classic examples of data integration are the overlaying of ILI data from two or more different types of tools and the overlaying of ILI data with other information such as coating condition, cathodic protection levels, or aerial surveillance records. In the first instance, an overlaying of data from a metal loss inspection with a geometry tool inspection may show that metal loss anomaly coincides with a geometric anomaly. The implication is that the anomaly is likely mechanical damage rather than corrosion-caused metal loss. In this case, the operator may elect to investigate the anomaly even though the metal loss or deformation anomaly alone would not warrant investigation. In the second instance, overlaying ILI data showing a metal loss anomaly with the knowledge from aerial surveillance records that a utility company had been seen installing poles and guy wires near the right-of-way at that location may indicate mechanical damage from the pole auger.

7.2 Effective Data Integration

The structure and breadth of many pipeline companies may result in relevant data being produced and stored in different locations, by disparate owners, using potentially inconsistent formats. Policies and procedures within the SMS are one way to ensure that the necessary inputs are effectively aggregated and normalized. Operators should develop and implement procedures to:

— identify the types of data needed to support integrity management (discussed in 7.3),
— identify the location of the data within the organization,
— deliver identified information from the data owner to the group responsible for data integration and analysis,
— disseminate integrated data and the knowledge generated to the applicable stakeholders across the enterprise responsible for identifying and managing integrity threats.

Where the data are missing or lack sufficient quality, operators may need to account for the additional uncertainty. Section 5 of API Bulletin 1178 provides guidance on elements of data quality that are needed to ensure the data are
fit for purpose in supporting the intended process. The use of default values in the absence of actual data may be necessary at times, but the acquisition of actual data should be pursued when possible. The use of default values should be delineated such that inferred versus actual values can readily be identified.

7.3 Types of Data to Integrate to Support Integrity Management

7.3.1 General

The types of data used to assess the threats and associated risk to a pipeline segment or facility can be broadly categorized as pipe attributes, construction factors, operating parameters, and assessment history. The data elements listed below should be collected and integrated in support of an integrity management program. Where an operator determines that data is missing or incomplete, the operator should attempt to collect this data. If this data is not collectible, appropriate estimates should be used to replace it. The operator may consider implementing mitigative measures they deem necessary for the facility or pipe segment.

7.3.2 Pipeline Attributes

Pipeline attributes are typically contained on alignment sheets or system maps. The following is a representative list of these data elements:

— Pipe and system attributes—diameter, wall thickness, specified minimum yield strength (SMYS), manufacturer, dates of manufacture and construction, type of pipe (seamless, seam welded, and spiral), type of seam (low-frequency (LF) or direct current (DC) ERW, high-frequency (HF) ERW, flash welded (FW), single or double submerged arc welded), pipe coating, girth weld (GW) coating, operating pressures, and maximum design temperature;

— Appurtenances—valves (types and performance characteristics), flanges, fittings, dead legs, and instrumentation lines;

— Facilities—pump stations, booster stations, and terminals;

— Crossings—highway and road crossings (cased or uncased, and shorted where applicable), water crossings (river, creek, and lake), pipeline and other utility crossings, shared right-of-ways, and power lines (crossing and parallel);

— Corrosion mitigation and monitoring equipment

  — External corrosion—CP test stations, sacrificial anode installations, impressed current installations, and isolation equipment, AC and stray current mitigation

  — test stations, isolation equipment, voltage mitigation equipment, and monitoring equipment, Internal corrosion

  — inhibitor injection equipment, fluid sampling equipment, and monitoring equipment.
7.3.3 Construction Factors

Construction factors can typically be sourced from design and construction records. The following is a representative list of these data elements:

— Construction—year, season, GW data including type, alignment and inspection, special protection (directional drills, concrete coating, barriers, and warning strips), pipeline weights installed during construction (types and locations);

— Coating installation method—over-the-ditch versus factory-applied coating of pipe and field coating of joints;

— Right-of-way—soil type (sand, silt, clay, and rock), soil resistivity, depth of burial, width of right-of-way, land use, and terrain.

7.3.4 Operating Parameters and History

Pipeline operating data elements can be found in the operator’s Operation and Maintenance manuals, Standard Operating Procedures or Operator Training materials, or a combination thereof. Others, such as representative pressure histories, test lead survey reports, valve inspection reports, river crossing inspection reports, and the actual records of aerial or ground patrols, will be contained in operating and maintenance records. The following is a representative list of these data elements:

— Operating Parameters—type(s) of liquids transported, bulk flow velocity, representative pressure histories, operating temperature range;

— Systems and Processes—SCADA and leak detection attributes, emergency response plans, public awareness program, one-call systems, excavation monitoring policy, qualifications and training programs, quality assurance practices, signage and markers requirements;

— Inspections—test lead surveys, river crossing inspections, valve inspections, cleaning pig frequency, inhibitor or biocide applications, aerial and ground patrol frequencies; and

— Reports—failure investigations, leak histories, incident reports, near-miss reports, soil and water sampling reports, corrosion coupons, and resistance measurements.

7.3.5 Integrity Assessment History

Pipeline Integrity assessments will be contained in documents describing specific tests or inspections and the results. The following is a representative list of these data elements:

— Pressure levels achieved in previous hydrostatic test and test failure history;

— Anomaly lists from previous ILIs along with disposition of anomalies;

— Results of any additional assessments such as close-interval pipe-to-soil potential surveys, DCVG surveys, pipeline current surveys, soil resistivity surveys, direct visual inspections of the pipe and the coating, right-of-way condition surveys, and depth-of-burial surveys;

— Documentation of severe weather events and outside force exposure including hydrotechnical scour, slope instability, and seismicity;

— Previous repair types and practices.
7.4 Data Maintenance (Management of Change)

Various data elements used to assess the applicability of a threat and its potential for failure may change with time. These changes may be caused by modifications to operating practices, changes in land use, or changes in pipe properties associated with replacements, reroutes, and new lines. The pipeline operator should be alert to these types of changes and make certain that the data used for threat and risk assessment reflect the current conditions of the pipeline.

7.5 Integration of Data to Validate MOP

An owner or operator of a pipeline should have traceable (i.e. clearly linked to original information about a pipeline segment or facility) records of the essential variables that support the determination of MOP. These attributes include the specified minimum yield strength (SMYS), wall thickness, diameter and hydrostatic test pressure. As an alternative to address gaps in historical documentation and records, the operator may resolve this information from one or more assessments, such as ILI, pressure testing, or in-situ examination.

Information from a transcribed document with its implied uncertainty, in many cases, should be verified with complementary or supporting documents (e.g. pressure charts or field logs), where available. Similarly, complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking. An affidavit prepared and signed at the time of the assessment by a qualified individual familiar with the assessment would be acceptable, as verified complete, and complementary documentation.

Where an aggregation of records completely spans a pipe segment, linkage to an individual pipe joint within the segment is not necessary. For instance, if multiple hydrostatic test sections completely span a pipe segment and adequately support the MOP, delineating exactly where the transition point is between tests is not required if they are continuous.

8 Risk Assessment Implementation

8.1 General Considerations

Risk to a liquid pipeline system arises from the combination of the probability that the system will sustain damage from one or more of the 10 threats listed in Section 5 and Annex A and the consequences (in terms of effects to critical locations as defined in Section 6) if the damage is sufficient to cause a release. Risk is commonly described as the product of the likelihood of a release times the consequences of the release. The higher the product of these two quantities, the higher the risk as depicted in Figure 3. By assessing risk as it varies throughout a pipeline system, a pipeline operator can identify and categorize locations according to risk. Prioritizing or ranking the calculated risks allows the operator to direct risk management personnel and resources to various parts of the system in a manner that has the most impact on system integrity. Risk can be described in either relative or absolute terms. Relative risk considers how the identified risk ranks compared to other risks identified on the system or segment. Absolute risk considers the expected consequences based on occurrence of the identified risk element.

When developing a risk assessment approach, it is important to understand the end use of the assessment. Risk assessments should be used for determining the type and order of integrity assessments (see Section 9) and preventive and mitigative action implementation (see Section 11). The need for the risk assessment to identify which threats are relevant to the asset in question and also to prioritize the order in which follow-up activities are implemented should be considered when the risk assessment approach is designed.
8.2 Developing a Risk Assessment Approach

Risk assessment has one or more of the following goals depending on the approach:

— to identify relevant threats to a given pipeline segment's integrity;

— to rank segments of a pipeline system in the order of greatest need for additional integrity assessment or mitigative action;

— to determine any segments where the risk level has exceeded the desired threshold

— to compare different prevention or mitigation options in terms of the risk reduction benefits and costs;

— to provide risk-based input to guide integrity decision making (e.g. repair criteria, reassessment intervals, etc.); and

— to facilitate reassessment and re-ranking once the preventive and mitigative actions have been completed.

A pipeline risk assessment process should address the following questions.

1) What kind of events or conditions might lead to a loss of system integrity?

2) How likely, in a relative or absolute sense, are these events or conditions to occur?

3) What are the nature and the severity of the consequences if these events or conditions occur?

4) What risks are associated with these events or conditions either in a relative sense or an absolute sense?

There are several approaches that can be taken to implement a risk process, each of which will provide answers to questions 1) through 4) above. The approaches vary in complexity depending on the complexity of the asset in question, the data needed to complete the process, and the quality and quantity of data available. The use of subject matter experts (SMEs) to design and implement risk processes is critical regardless of the approach taken. The following are generally accepted approaches:

— using SMEs;

— using a relative risk assessment;

— using a scenario-based model;

— using a probabilistic risk assessment.

Using SMEs—Typically, SMEs will be experienced company personnel who specialize in the subjects of relevance to pipeline integrity such as design, construction, corrosion mitigation, inspection and testing, maintenance, risk management, right-of-way maintenance, and operations. They will have detailed knowledge of the systems including size and nature, the critical locations (see Section 6), which of the 10 threats to pipeline integrity may be applicable to the system, and the types of data outlined in Section 7 (i.e. the pipeline attributes, the construction factors, the operational factors, and the assessment history). The SMEs jointly evaluate the threats to each pipeline segment, and consider the boundaries of critical locations to estimate the risk for each segment, and provide a relative ranking of segments for integrity assessments. The SMEs may or may not request assistance from an outside consultant but usually review relevant technical literature, and where possible, industry-wide data sources to aid them in their evaluations of threats to pipeline integrity.
Using a Relative Risk Assessment—In a relative risk assessment, an arithmetic model is developed or an existing model is purchased that allows numerical scores to be calculated for each pipeline segment based on the identified threats to pipeline integrity and the nature and distribution of critical locations that could be affected by a release. Probabilities and consequences are expressed as equations containing the relevant parameters that are typically multiplied by weighting factors that have been validated by sensitivity studies and comparisons to historic situations. Typically, these models provide algorithms for calculating the risk score associated with each individual threat. These models typically provide for calculating the effects of integrity assessments and mitigation on the basis of the score of a given segment. Thus the value of potential integrity assessment methods and mitigative actions appropriate for addressing a particular threat can be compared prior to their selection and use. The scores that result provide comparisons that are relative to each other; hence, the method is termed “relative” risk assessment. Pipeline segments can be ranked according to the calculated scores with the highest relative risk sections being scheduled first for assessment and mitigation. Re-ranking of segments can also be carried out after a round of assessments has been completed, and this allows the operator to plan the next assessment based on the re-ranking.

Using a Scenario-based Model—This approach involves considering events or sequences of events that lead to the risk of a release. A probability is assigned to each event based on a historical rate of occurrence. A fault tree is constructed from the interaction of individual events that leads to a calculated probability of a release. Fault Tree analyses can be constructed for each of the 10 threats listed in Section 5 and Annex A that are considered to be applicable to a given pipeline segment. The probability that releases of different types will occur within the boundaries of a segment where it could affect a critical location and the associated costs can be considered by means of a Fault Tree analysis as well. By multiplying the probability of the release occurring within a critical location times the cost of
potential damage and cleanup following a release, the operator obtains an “expectation” in cost terms for each scenario. The operator calculates expectations for all applicable scenarios and compares the results to determine which segments need integrity assessment soonest.

Using a Probabilistic Risk Assessment—This method requires the consideration of probabilities of undesirable events (such as a release or the remaining pressure carrying capacity of the pipe falling below the MOP of the pipeline in a segment located within the boundaries of a critical location) and their associated costs. Integrity assessments can then be implemented on the segments for which the calculated risk (probability times consequence) of the undesirable event is unacceptably high. Probabilistic risk assessment requires large amounts of reliable data to establish credible probabilities of events and situations. An example is the use of probability-of-exceedance (POE) for mitigating external corrosion following an ILI. Each anomaly identified through the inspection has length and depth dimensions, as predicted by the inspection technology, which are used to calculate an ERP based on the properties and operating parameters of the pipe. The uncertainty embodied in the tool error allows the calculation of the probability that a detected and sized anomaly will leak or fail at the MOP at the location of the anomaly. The operator should then choose a probability level and remediate anomalies having a higher probability; the inference is that this probabilistic approach would supersede prescriptive response criteria.

8.3 Characteristics of Risk Assessment Approaches

A pipeline operator needs to be aware of certain characteristics of risk assessment methods to use them appropriately. One is that they are data driven. As shown in Section 7, system data consisting of pipeline attributes, construction factors, operational factors, and integrity assessment histories should be available to assess the risk of each threat to pipeline integrity. The nature and extent of the critical locations should be well defined to determine the ways in which a pipeline release can affect a critical location as outlined in Section 6. The quality of the risk assessment is related to the quality of the data used and the expertise provided by the operator.

Probabilities of releases and consequences can be meaningfully combined to calculate risk for a specific location only if the data used in the calculation apply to that location. Therefore, all data should be available and valid for the location to which the calculations apply. Some models use dynamic segmentation, which provides for a continuous interrogation of the pipeline data along the route, calculating a new value of risk every time any input variable changes. Other models use fixed segmentation, which is designed to calculate risk for a specific set of data applied to a predefined segment with constant values of the input data. In the case of dynamic segmentation, points of data change should be provided. In the case of fixed segmentation, the user should define segments for which the data remain constant.

In some situations, data weaknesses may lead to risk scores being driven by a single variable in a way that creates doubt about the reliability of the risk scores. For example, if a model shows the probability of external corrosion to be based on coating type, coating condition, soil type, age, and pipe-to-soil potential readings and the assumption is made that coating type, coating condition, soil type, and age are constant throughout the segment, the risk will be totally controlled by the pipe-to-soil potential readings. It is unlikely that coating condition and soil type are constant over long distances, so to obtain a more reliable calculation of the corrosion threat, the operator could invest in efforts to determine how coating condition and soil type vary along a pipeline. For each risk calculation, threat-by-threat, the operator needs to examine both the data being used, and the output calculations to be sure that they agree with experience.

To determine the rate of mitigation needed to avoid a failure within an unassessed segment, the operator who uses relative risk scores should review the results of the assessments, remediations, and mitigations from the first few segments with the highest scores. Working through the first few segments provides an indication of the reliability of the risk assessment. The operator can then adjust the rate of integrity assessment and preventive and mitigative measure implementation accordingly.

Because the scenario-based approach and the probabilistic approach to risk assessment tend to give risk values in terms of probability of failure, the user has to decide how much risk to accept for a given period of time. For example, a probability of failure of $1 \times 10^{-6}$ might indicate that a segment could go X years before needing an integrity
assessment whereas a probability of failure of $1 \times 10^{-3}$ might suggest a need for integrity assessment within $Y$ years where $Y$ is considerably less than $X$.

Risk assessment is not static and does not deliver absolute certainty regarding scheduling integrity assessments or other preventive and mitigative activities. However, it does offer a methodology with which to start an integrity assessment program, and if allowed to evolve with experience, it becomes a tool for continual planning of integrity assessments. Risk assessment should also continually identify those preventive and mitigative measures an operator should be considering for implementation. As integrity assessments, remediations, and mitigative actions are carried out, the particular model used by an operator can be validated, improved, or replaced, if necessary, to conform with the experience gained through integrity management activities. The properly evolving risk assessment model will remain an essential tool for planning integrity assessments and preventive and mitigative actions in the future in a manner that ensures the continued integrity of the system.

The experience that comes from carrying out integrity assessments and mitigative actions should be fed back into the risk assessment process for it to remain reliable. Data that should be gathered for future integration and considered in reassessing risk (that may necessitate modifications to the risk assessment approach) are discussed in detail in API Bulletin 1178. Some examples are as follows:

— number of repairs required during the previous inspection, testing, and mitigative activity;
— type of defects found and their significance to pipeline integrity;
— causes of defects found;
— rate of degradation;
— different assessment technologies and improvements in technology used;
— changes in pipeline attributes and pipeline operations;
— alignment of findings from inspections and tests with what the model predicted;
— results of preventive and mitigative actions.

9 Integrity Assessment and Remediation

9.1 General

This section provides guidance on integrity assessment methods and repair methods, and includes the following topics:

— appropriate ILI techniques for the various pipeline integrity threats;
— schedules for dealing with anomalies found by ILI;
— benefits and limitations of hydrostatic testing;
— various types of other technologies for finding anomalies;
— various types of repair methods that can be used to restore the serviceability of pipe affected by defects.

The threats for hazardous liquid pipelines that operators should address are listed in 5.1 and explained in detail in Annex A.
The categorization of the threats as time-dependent, stable or time-independent (random events) is provided in the ASME B31.8S standard for gas transmission pipelines. Liquid pipeline operators should consider the physical and regulatory differences between gas and liquid pipelines since the potential for pressure-cycle-induced fatigue is much greater for liquid pipelines than it is for gas pipelines. An additional category, potentially time-dependent, can be helpful in categorizing some threats in liquid pipelines. Table 1 lists the categories for the threats listed in this RP. The internal corrosion, external corrosion, SSWC, and EAC threats are clearly time-dependent threats that should be addressed by periodic assessment and monitoring. The manufacturing, construction and fabrication threats are considered possibly time-dependent threats because of the potential for their enlargement by fatigue. For the latter threats, the pipeline operator will be called upon to determine the need for additional assessments or monitoring. The equipment failure, incorrect operations, weather and outside force threats along with the immediate mechanical damage threat are considered time independent because they involve random events for which the time of occurrence is usually not predictable. Management of time independent threats involves employing preventive and mitigative measures.

**Table 1—Threat Categories**

<table>
<thead>
<tr>
<th>Time Dependent Threat</th>
<th>Potentially Time Dependent</th>
<th>Time Independent (Random Events)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Requires Periodic Assessment and Monitoring</td>
<td>Requires Analysis of Need for Periodic Assessment or Monitoring</td>
<td>Occurrence Not Predictable</td>
</tr>
<tr>
<td>External Corrosion</td>
<td>Manufacturing Defects</td>
<td>Equipment Failure</td>
</tr>
<tr>
<td>Internal Corrosion</td>
<td>Construction and Fabrication Defects</td>
<td>Mechanical Damage (causing immediate failure)</td>
</tr>
<tr>
<td>SSWC</td>
<td>Mechanical Damage (that does not cause an immediate failure)</td>
<td>Incorrect Operations</td>
</tr>
<tr>
<td>EAC</td>
<td></td>
<td>Weather or Outside Force</td>
</tr>
<tr>
<td>Fatigue</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

If no prior integrity assessment has been performed for a pipeline system, an initial integrity assessment plan should be developed based on identifying critical locations (Section 6), initial data gathering (Section 7), and risk assessment (Section 8). If prior integrity assessments have been performed, the integrity assessment plan going forward should be modified by reviewing critical locations for possible changes or additions (Section 6); reviewing and updating data in response to changes in attributes, changes in operations, knowledge gained from company and industry failure reports, and the results of prior assessments (Section 7); and by reassessing risk and reprioritizing segments for future integrity assessments. The relation of these activities to other integrity management functions and their placement in the PDCA cycle of activities is discussed in Section 4.

It is expected that the appropriate pipeline integrity assessments will be performed periodically and remediation activities will be carried out at intervals that are appropriate to prevent releases that might result from time-dependent deterioration (especially for the time-dependent threats described previously). Reassessments are discussed in Section 10 and guidance for calculating reassessment intervals is given in Annex D.

Regardless of the assessment or repair method selected, the operator should have applicable written procedures and adequate training regarding them. When outsourcing integrity assessment or remediation activities the operator should define responsibilities and accountability. API RP 1173 provides additional guidance on operational controls that can be used to establish and improve integrity assessments and remediation.

Table 2 shows applicable integrity assessment methods for each threat discussed in Section 5. This list is not meant to be all inclusive and does not preclude the use of ILI, hydrostatic testing, or different technology for use in certain threat assessments proven to be effective through experience.

### 9.2 In-line Inspection

This section presents guidelines for the use of ILI technology to assess pipeline integrity. The generic classes of ILI tools and a brief overview of their capabilities are shown in Table 3 and detailed descriptions of the various ILI
<table>
<thead>
<tr>
<th>Threat</th>
<th>ILI</th>
<th>Hydrostatic Testing</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>External corrosion</td>
<td>a</td>
<td>a</td>
<td>ECDA</td>
</tr>
<tr>
<td></td>
<td>(preferred)</td>
<td></td>
<td>GWUT</td>
</tr>
<tr>
<td>Internal corrosion</td>
<td>a</td>
<td>a</td>
<td>ICDA</td>
</tr>
<tr>
<td></td>
<td>(preferred)</td>
<td></td>
<td>GWUT</td>
</tr>
<tr>
<td>SSWC (external or internal)</td>
<td>a</td>
<td>a</td>
<td>ECDA</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>ICDA</td>
</tr>
<tr>
<td><strong>EAC</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Axially oriented EAC</td>
<td>a</td>
<td>a</td>
<td>SCCDA</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>NDE</td>
</tr>
<tr>
<td>Axially oriented stress fatigue cracking and other cracks</td>
<td>a</td>
<td>a</td>
<td>NDE</td>
</tr>
<tr>
<td>Circumferential EAC</td>
<td>a</td>
<td>b</td>
<td>SCCDA</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>NDE</td>
</tr>
<tr>
<td><strong>Manufacturing defects</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Axially oriented crack-like seam defects (i.e. hook cracks, cold welds)</td>
<td>a</td>
<td>a</td>
<td>NDE</td>
</tr>
<tr>
<td>Hard spots</td>
<td>a</td>
<td>b</td>
<td>NDE</td>
</tr>
<tr>
<td>Laminations</td>
<td>a</td>
<td>b</td>
<td>NDE</td>
</tr>
<tr>
<td><strong>Construction and fabrication defects</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Defective girth weld</td>
<td>b</td>
<td>b</td>
<td>NDE</td>
</tr>
<tr>
<td>Defective fabrication weld</td>
<td>b</td>
<td>b</td>
<td>NDE</td>
</tr>
<tr>
<td>Wrinkle bends</td>
<td>a</td>
<td>a</td>
<td>NDE</td>
</tr>
<tr>
<td>Stripped threads, broke pipe, coupling failures</td>
<td>b</td>
<td>b</td>
<td>Visual Exam</td>
</tr>
<tr>
<td>Equipment failure</td>
<td>b</td>
<td>b</td>
<td>Visual Exam</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>NDE</td>
</tr>
<tr>
<td><strong>Mechanical damage</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Immediate failure</td>
<td>c</td>
<td>c</td>
<td>Damage Prevention Programs</td>
</tr>
</tbody>
</table>

*Note: The methods are represented as follows: a = accepted, b = backup.*
Table 2—Integrity Assessment Methods (Continued)

<table>
<thead>
<tr>
<th>Threat</th>
<th>ILI</th>
<th>Hydrostatic Testing</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delayed failure</td>
<td>a</td>
<td>a</td>
<td>Damage Prevention Programs NDE</td>
</tr>
<tr>
<td>(preferred)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Illegal tapping (vandalism)</td>
<td>a</td>
<td>b</td>
<td>Visual Exam</td>
</tr>
<tr>
<td>Incorrect operations</td>
<td>c</td>
<td>c</td>
<td>Operator Training and Qualification</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Procedures</td>
</tr>
</tbody>
</table>

Weather and outside force related defect

<table>
<thead>
<tr>
<th>Threat</th>
<th>ILI</th>
<th>Hydrostatic Testing</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vortex-induced vibration</td>
<td>b</td>
<td>b</td>
<td>Monitoring</td>
</tr>
<tr>
<td>Flooding</td>
<td>b</td>
<td>b</td>
<td>Monitoring Visual Exam</td>
</tr>
<tr>
<td>Lightning</td>
<td>a</td>
<td>b</td>
<td>Leak Detection</td>
</tr>
<tr>
<td>Ground movement (i.e. subsidence, earthquake, liquefaction, landslide)</td>
<td>a</td>
<td>b</td>
<td>Monitoring LIDAR ROW Patrol</td>
</tr>
<tr>
<td>High winds (i.e. hurricanes, tornadoes)</td>
<td>b</td>
<td>b</td>
<td>Monitoring Visual Exam</td>
</tr>
</tbody>
</table>

- a Represents commonly used industry practices.
- b Represents assessment practices which generally are not recommended due to limited effectiveness although in certain circumstances operators may have found them effective.
- c N/A = Non applicable

technologies appear in Annex B. Neither the information in Table 3 nor in Annex B should be considered all-inclusive of every tool and capability that is available. For example, using two types of tools and overlaying the results can provide useful information on interacting threats such as metal loss or cracking within a dent or cracking in combination with metal loss. ILI technology evolves rapidly such that tools may exist that are not covered in this RP. A pipeline operator is well advised to stay current with ILI vendors, technology center researchers, industry conferences, and other pipeline operators. Operators are encouraged to discuss improved inspection technologies with their vendors. Pipeline operators are encouraged to consult other industry standards on ILI including:

- NACE SP0102, In-Line Inspection of Pipelines;
- API Standard 1163, In-line Inspection Systems Qualification;
- API RP 1176, Assessment and Management of Cracking in Pipelines;
- ASNT ILI-PQ, In-Line Inspection Personnel Qualification and Certification;
- Pipeline Operators Forum, version 2016, Specifications and requirements for intelligent pig inspection of pipelines.
<table>
<thead>
<tr>
<th>Material/Condition</th>
<th>MFL Tools</th>
<th>Ultrasonic Tools (UT)</th>
<th>Geometry Tools</th>
<th>Pipeline Profile and Alignment Tools</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Axial MFL</td>
<td>Circumferential MFL (Transverse Field)</td>
<td>Residual or Low Field MFL</td>
<td>Normal Beam UT (Wall Thickness)</td>
</tr>
<tr>
<td>S is detection and sizing capability as specified by vendor.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>D is detection capability with limited or no sizing capability as specified by vendor.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>DM is detection capability of metal loss portion of mechanical damage with limited or no sizing capability as specified by vendor.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**NOTE 1** Refer to Table 1 of API RP 1176 for additional details on crack detection tools.

**NOTE 2** Inertial mapping tool information can be used to calculate safe operating pressure automatically.

\[a\] Requires offline calculation.

\[b\] With special setup.
9.2.1 ILI Tool Workflow

In planning for ILIs, the process flow diagram shown in Figure 4 (from API 1163) can be used to outline the workflow associated with conducting an ILI.

Figure 4—ILI Process Flow Diagram

A pipeline operator contemplating the use of ILI for integrity assessment should first determine whether the pipeline to be assessed can accommodate ILI tools. To accommodate ILI tools, the pipeline should be equipped either permanently or temporarily with the means to launch and receive tools, ideally, without taking the pipeline out of service. An appropriate tool should be available for the diameter of the segment to be assessed. Diameter or ovality restrictions, short-radius fittings, and miter bends may interfere with the passage of the tool. Dual diameter lines can be inspected but getting full assessment data can be problematic. Full-opening tees should be fabricated with bars that prevent a tool from turning into the branch. The fluid should be compatible with the tool both from the standpoint of not damaging the tool and from the standpoint that the fluid is capable of signal transmission if the technology relies upon signal transmission through the fluid. Many tools are sensitive to temperature extremes and fluctuations.

The cleanliness of the pipeline may be a factor in the effectiveness of an ILI assessment. Wax and solid debris may degrade the performance of an ILI tool. Lastly, capabilities of a tool for locating and sizing the target anomalies may vary with tool speed. In some instances, a tool can collect accurate data at flow rates faster than it can reliably survive the wear and tear of an inspection. Long runs and the presence of fittings can damage the tool. Therefore, in selecting tool speed, the run length and the number of fittings (check valves, tees, etc.) should be considered; additionally, check valves may need to be lifted open and locked in place. The pipeline operator may have to reduce bulk flow velocity to achieve satisfactory results. The operator should review relevant aspects of the pipeline with the potential ILI vendors before committing to use ILI tools (or sets of tools).

Different tools are designed to address anomalies created by different threats. It may be necessary to run multiple tools or combinations of tools if there are multiple threats to be assessed. The pipeline operator should carry out the data analyses outlined in Section 7 and the risk assessment outlined in Section 8 to identify any threats that could affect the segment to be inspected. Only then can an informed decision be made as to which ILI tools are appropriate for integrity assessment of a particular pipeline segment. Figure 5 outlines the terminology associated with the ILI analysis and deliverables.
First, although the tools typically measure distance traveled, the operator should work with the vendor to place above-ground marking equipment to “mark” the data as the tool passes particular locations. These markers, along with the known locations of other physical features, are needed to calibrate the distance measurements recorded for each anomaly to facilitate location of the feature if further examination is necessary. Some tools use inertial navigation or guidance systems to increase accuracy and ease of locating actionable anomalies. Inertial guidance tools (discussed in Annex B) combined with integrity assessment tools can obtain pipeline position information and assign calculated GPS coordinates. API Bulletin 1178 provides additional guidance and considerations regarding the use of GPS coordinates.

Second, there are several attributes of an ILI technology that will control whether and how features are reported. The ability of an ILI technology to detect an anomaly is based on the depth and magnitude threshold for the particular
anomaly. The probability of detection (POD), typically reported as an 80% or 90% confidence (typically this increases for larger anomalies), is controlled by a combination of depth, type, shape and possible location of the anomaly. Even if detected, the anomaly also needs to be correctly characterized, typically referred to as probability of identification (POI). Incorrect identification may result in an anomaly being erroneously characterized as non-injurious or non-actionable. The operator should understand the limitations of each type of tool prior to its use. The operator can assess the tool’s probability of detection and probability of correct identification by comparing field findings with reported anomalies.

Third, many tools have the ability to characterize the sizes of anomalies within a certain stated tool tolerance; and as such, the anomaly sizing found upon excavation and measurement are often different to some degree from the sizes predicted by the tools. The operator should determine the amount of tool error associated with a particular tool run by excavating and examining a representative number of anomalies while also considering field measurement error. The statistical distribution of error should be considered in the evaluation of the tool’s performance and the evaluation of other anomalies for remediation.

In some cases, special ILI tools can be set up to locate certain types of anomalies. For example, if pipe body hard spots are suspected, an MFL ILI tool can be used in a special setup to locate them. For additional information, see Annex A.

The pipeline operator should be aware that the routine grading of anomalies provided by an ILI vendor may not be sufficient to satisfactorily assess certain anomalies. In such cases, the operator may find it advantageous to request a reexamination by the vendor of the raw data acquired by the tool. Analysis of the raw data by the vendor’s experts may help in assessing a particular anomaly where the normally reported data were insufficient to resolve the nature of the anomaly particularly when detailed data integration is needed to identify threats.

9.2.2 Validating ILI Tool Performance

API 1163 describes three methodologies that can be used to validate that the reported inspection results that meet or are within the performance specification for the pipeline being inspected or to establish the as-run specification on the basis of validation data.

— An operator may have a unique understanding of the threat mechanism or access to other datasets that provide the opportunity for additional insight into characterizing anomalies from an ILI. Application of this value added interpretation may give rise to a two-tier performance specification; the first one “as reported by the service provider” and the second one “as interpreted by the operator.” This is exemplified by the approach detailed in API RP 1176 where cracking anomalies are characterized as likely, possible, or unlikely. This approach does not limit the service providers’ obligations to meet or exceed their performance specifications in terms of the “as-reported” data.

— In terms of validating tool performance for multiple ILI runs, consideration should be given to the commonality of essential variables across runs. This can provide the opportunity to aggregate multiple ILI runs to determine and apply the calculated sizing error.

— A root cause analysis (RCA) may be considered for results of individual features that significantly vary from the performance specification such as those incorrectly sized by twice the 80% certainty sizing error. Typically a RCA is reserved for anomalies of significance, but it could be engaged where the remaining population of features merits additional consideration.

9.2.2.1 Artificial Feature Validation

Early in the life of the pipeline or new assessment type, it is unlikely any suitable anomalies will be detected, making it difficult or impossible to validate data. Thus, the operator may consider using manufactured metal-loss or crack (notch) anomalies reinforced with steel or composite sleeves to validate in-line inspection tools. The use of machined features guarantees a full spectrum of anomaly geometries and severities are considered in preparing unity plots.
also ensures enough features are provided to statistically evaluate the true probability of detection and sizing accuracies across the full range of potential anomalies. Consideration should be given to the placement of calibration spools with machined defects spools at the beginning, mid-point, and end of the pipeline. The installation of sleeve repairs should result in the higher burst pressure ratings than the original pipe. Using a machined-premeasured set of anomalies for tool validation precludes the need to conduct excavations, which could damage the sensitive ecosystem. Also, because all features were accurately measured in a controlled environment, there is less potential for measurement error.

9.2.3 Responding to Anomalies Identified by ILIs

9.2.3.1 General

The central part of this methodology is to determine an appropriate response for each anomaly called out by an ILI tool. To most effectively respond to anomalies found by ILIs, operators should have a fundamental understanding of the abilities and limitations of the ILI technology used and the operating parameters of the pipeline in question. This operating knowledge should be known about the specific location of the anomaly as much as practical. Critical parameters, such as the permissible pressure at that location, potential pressure at that location during a transient or abnormal event, or maximum potential pressure achievable during steady state operations should all be known to correctly categorize the severity of anomalies found. Hydraulic gradients and pressure surges can cause these critical parameters to vary widely from location to location, and an operator should know the differing level of risk when comparing the safe pressure capacity of anomalies to these different parameters.

Pipeline operators are reminded that some regulatory jurisdictions have requirements for the examination and repair of certain injurious defects and that the recommended timing for examination and repair listed below may differ. In addition, certain regulations also contain reporting requirements when certain conditions are found.

9.2.3.2 Discovery of Condition

Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. Operators should establish a reasonable process and timeline for discovery (e.g. six months after completion of the tool run).

In general, an operator, who becomes aware of an integrity-threatening condition, should take appropriate action within a reasonable amount of time to confirm the status of the condition by further analysis and to remediate the condition, if necessary, so that the integrity of the pipeline is no longer threatened. Discovery includes receiving dimensions of an anomaly from an ILI vendor that indicate the existence of an integrity-threatening anomaly. For example, the operator receives information that a particular metal loss anomaly exists that has ILI-indicated dimensions that result in a calculated failure pressure that is at or below the operating pressure at the location of the anomaly. Similarly, the finding based on geometry tool data, of a dent on the topside of the pipe that has a depth exceeding 6 % of the diameter of the pipe constitutes discovery of a potentially integrity-threatening condition. Discovery could also mean finding upon overlaying data from a geometry tool and a crack-detection tool that a crack coincides with a dent creating a potentially integrity-threatening condition. Operators should establish a communications protocol with the vendor for timely reporting of anomalies that may require urgent action.

The pipeline operator should excavate and examine those anomalies that appear on the basis of the high-level screening of ILI data to be an immediate response condition (as defined in 9.2.2.3), that is, potentially a threat to pipeline integrity. The effect of an anomaly on the remaining strength of a pipeline depends on its physical dimensions and the strength and (in the case of a crack-like anomaly) the toughness of the material. When the remaining strength of an anomaly is lower than the potential stress in the pipe wall that could be achieved during current and future operations, then certain immediate actions are warranted. The comparison of remaining strength to pipe stress should consider internal design pressure, MOP, and potential surge pressures. When operators cannot take immediate action to repair these defects, they should consider lowering their operating pressures. The remaining strength calculations provide a basis for determining appropriate operating levels. When remaining strength cannot be calculated, then a pressure reduction may be based on previous operating history. Historically, a 20 % reduction
from previous known operating pressure has been used, but operators should analyze each specific system to
determine the pressure reduction that is appropriate. Models for predicting the effects of certain types of anomalies on
the pressure-carrying capacity of pipe are available in various pipeline industry publications. Generically, these
models are termed fitness-for-service models or engineering critical assessment models.

From the standpoint of corrosion-caused metal loss, the applicable ILI technologies provide axial length and depth-of-
wall-thickness-penetration dimensions with sufficient accuracy that reasonable predictions of remaining pressure-
carrying capacity can be made with confidence based on the data obtained from a given tool run. The list of graded
anomalies will indicate to the pipeline operator the locations and severities of anomalies that need to be addressed to
preserve the integrity of the pipeline.

The data obtained from crack tools may be of adequate quality to permit the grading of cracks as well; the ability to
accurately depict the crack type anomaly is dependent on the technology as well as the type of feature (e.g. ERW
seam crack versus SCC or circumferential field MFL versus ultrasonic). API RP 1176 details the considerations
applicable to the various crack ILI technologies as well as the associated fracture mechanics calculation methods.

To calculate an estimated rupture pressure (ERP) to determine remaining strength, selection of a suitable calculation
method depends on several factors, including the failure mode of the anomaly. Appropriate calculation methods
include but are not limited to:

Remaining Strength of Corroded Pipelines* (2012) or AGA Pipeline Research Committee Project PR-3-805, *A
Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe* (December 1989); anomalies with a
predominantly circumferential extent may be assessed with the Kastner et al (1981) local collapse (flow stress
dependent) failure criterion; other suitable models exist and are in common usage.

b) For crack anomalies or SSWC associated with FW and vintage ERW seams susceptible to failure through fracture
narrow metal loss susceptible to fracture—the Battelle Model (Modified Log-Secant), IPC 2016-64605, or
API 579, Part 9; consideration for delineating SSWC from corrosion which is coincidental to the seam weld is
discussed in Annex A.

c) For dent anomalies: the safe working pressure can be determined using PRCI PR-218-063505, *Safe Inspection

d) For all anomalies: If the formulas above are not applicable to the type of anomaly, an operator should use an
alternative acceptable method to calculate a reduced operating pressure, or implement additional measures to
provide acceptable operating parameters, or reduce operating pressure at the location of the anomaly by a
minimum of 20%.

The characterization of a crack is further defined in API RP 1176, but a succinct summary is provided here for ease of
reference. A key aspect in the crack response methodology is determining the likelihood that an ILI indication is a
crack. A likely crack is defined as having a reasonable degree of confidence that the anomaly called by the ILI vendor
correlates to a crack-like defect. This can be the case where the operator's previous experience on a pipeline
segment or other similar pipeline segments has found cracks or the case where the data integration indicates a strong
likelihood that cracks could exist even though no historical data suggests cracking has occurred. A possible crack is
defined as having a reduced certainty of being, or rarely been, an actual crack. When it is a crack, it occurs under
different circumstances or the operator cannot determine with a high degree of confidence that the indication is not a
 crack-like defect.

Whenever pressure reductions are implemented, including long-term pressure reductions, regulatory statutes for
reporting and timing should be followed. A schedule for addressing anomalies judged not to be immediate response
conditions but which could affect pipeline integrity in the future should be established that will ensure that mitigative
action is taken in time to prevent a leak or a rupture of the pipe. Section 10 provides guidance for assessing the
remaining life of anomalies that fall outside the category of immediate or near-term response conditions. An operator
should consider the calculated failure pressures of the associated anomaly population relative to future, normal and maximum operating pressures of the pipeline segment when deciding the extent of further long-term pressure reductions.

9.2.3.3 Immediate Response Conditions

When a pipeline is inspected by an ILI tool, the final results of the inspection should be provided to the operator within a reasonable timeline. Anomalies that meet the immediate response criteria should be brought to the operator’s attention through a preliminary ILI report as soon as practicable after completion of the inspection.

Immediate response conditions describe anomalies or conditions that could potentially represent severe and immediate threats to pipeline integrity. The operator should consider mitigation within five days whether they are found within a segment of pipeline that could potentially impact a critical location or not. In absence of further analysis removing the anomaly from the immediate response, mitigation would typically entail excavation and repair. Alternatively, an operator may temporarily reduce the operating pressure or shut down the pipeline to provide additional time to complete the repair. The temporary pressure reduction shall be determined by considering the remaining strength of the anomaly. Where the remaining strength of an anomaly cannot be calculated, the operating pressure should be reduced by a minimum of 20 %. Although such a temporary pressure reduction can be maintained for up to a year, immediate features should be mitigated in accordance with regulations and as expeditiously as practicable.

Immediate response conditions include, but are not limited to, the following:

a) Metal loss greater than 80 % of nominal wall regardless of dimensions;

b) Likely crack anomalies greater than 70 % of nominal wall or of an indeterminable depth that exceeds the maximum depth sizing capabilities of the tool, as stated by the vendor’s performance specification, where the depth cannot otherwise be established through correlation with previous ILI runs. These criteria are not intended to include tool tolerance in depth comparisons.

c) A calculation of the remaining strength of the pipe at the metal loss or likely crack anomaly that shows a failure pressure ratio (FPR) less than 1.1 at the location of the anomaly. The FPR calculation is not intended to include tool tolerance.

d) A dent, located anywhere on the pipeline, that has any indication of a gouge, likely or possible crack, or stress riser, unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity.

e) A dent located on the top of the pipeline (above the 4 o’clock and 8 o’clock positions) with a depth greater than 6 % of the nominal pipe diameter unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity.

f) An anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

9.2.3.4 Near-term Response Conditions

The following sets of investigation and response criteria describe conditions that could, if left unaddressed, represent threats to pipeline integrity. The prescribed timing depends on whether the anomaly is on a section of pipe that could affect a critical location or not, within 270 days that could affect a critical location and 540 days if it does not affect a critical location. Operators should understand the growth mechanism(s) for each anomaly and verify that the time to failure (including appropriate safety factors) of these anomalies is not less than the time period for response. Anomalies that are predicted to fail within this period should be scheduled for remediation prior to their projected failure date. These criteria are not intended to include tool tolerance in depth comparisons or ERP calculations.
Applicable conditions include:

a) A dent with a depth greater than 2% of the pipeline’s diameter (0.250 in. in depth for a pipeline diameter less than NPS 12) that interacts with a girth weld or a longitudinal seam weld unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity.

b) A dent located on the top of the pipeline (above 4 and 8 o’clock position) with a depth greater than 2% of the pipeline’s diameter (0.250 in. in depth for a pipeline diameter less than NPS 12) unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity.

c) A dent located on the bottom of the pipeline with a depth greater than 6% of the pipeline’s diameter unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity.

d) A calculation of the remaining strength of the pipe at the metal loss, likely crack (that is time dependent or possibly time dependent) or possible crack (that is time dependent) anomaly that shows an FPR less than 1.25 at that location.

e) An area of general corrosion with a predicted metal loss greater than 50% of nominal wall.

f) SSWC with a predicted metal loss greater than 50% of nominal wall.

g) Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld.

h) A likely crack (that is time dependent or possibly time dependent) or a possible crack (that is time dependent) with depth greater than 50% of nominal wall.

i) A dent located anywhere on the pipeline with corrosion unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity.

j) A gouge or groove greater than 12.5% of nominal wall resulting from mechanical damage.

9.2.3.5 Scheduled Response Conditions

An operator should investigate and, if necessary, repair items a) and b) below prior to the condition being met unless the next inspection period is scheduled to precede it.

Following an integrity assessment, time dependent threats should be evaluated for response timing. These calculations should include:

a) a calculation of the remaining strength of the pipe (including allowances for growth and tool measurement error) to show an FPR less than 1.1 at the location of the anomaly,

b) a calculation of the maximum depth of a metal loss feature (including allowances for growth and tool measurement error) predicted to be greater than 80% of nominal wall regardless of dimensions.

If an anomaly fails a scheduled response criterion including tool tolerance but without the application of growth, the anomaly should be addressed as a Near-term Response (i.e. 270 days or 540 days). The applicable discovery date may be delayed depending upon when the elevated tool measurement error was determined. Additional guidance on scheduled response conditions for cracks can be found in API RP 1176.
9.2.3.6 Monitored Conditions

An operator does not have to schedule the following conditions for remediation but should record and monitor the conditions during subsequent integrity assessments for any change that may require attention.

a) Any manufacturing or construction condition that an industry recognized engineering evaluation or technical analysis shows to be stable and for which operating conditions have not significantly changed since the last successful pressure test; or

b) Any condition identified by an integrity assessment or information analysis that is not currently deemed to impair the integrity of the pipeline.

Additional guidance on monitor conditions for cracks can be found in API RP 1176.

9.3 Hydrostatic Pressure Testing

9.3.1 General

Hydrostatic testing is a widely used method of establishing MOP, integrity verification when records are incomplete or missing, and conducting a periodic integrity assessment of existing pipelines as part of an integrity management program. Its value as an integrity assessment technique is embodied in the probability that increasing the test pressure beyond the MOP will cause defects that are critical at the test pressure to fail thereby eliminating the possibility that the defects could fail at the operating pressure. The higher the test-pressure-to-operating-pressure ratio, the more effective the test is as a demonstration of pipeline integrity. API RP 1110 provides additional guidance for performing pressure tests.

In most cases, pressure testing is conducted with water. However, in certain conditions, other media such as nitrogen or another inert media may be used. When using an alternative medium than water, consideration should be given to safety and environmental concerns.

Hydrostatic testing is generally suitable for assessing flaws associated with time dependent and stable threats (see Section 5 and Annex A for more information on threats), each specific threat needs to be matched with the appropriate integrity assessment options.

ILI tools have proven to be more effective than hydrostatic testing for identifying small corrosion pits. Short, deep pits that would be detectable by ILI may survive a hydrostatic test but leak soon thereafter. Moreover, the ILI results show where corrosion is occurring and record the locations and dimensions of corroded areas that, while not in danger of imminent failure, may become a problem if corrosion continues. In addition, hydrostatic testing is generally not effective for assessing circumferential flaws, such as girth weld defects or circumferential SCC, because the applied stress is from axial loading or longitudinal bending, not internal pressure. API TR 1179 provides detailed guidance on the applicability of hydrostatic testing for integrity management. Hydrostatic testing may be used to validate ILI processes for specific threat management (see API TR 1179 and API RP 1176).

Where hydrostatic testing is an appropriate assessment method, a test either eliminates defects that have failure pressures less than the test pressure or it shows that any surviving flaws have failure pressures at or above the test pressure (except for the possibility of a pressure reversal as explained in Section 9.3.6). The validation provided by a test is highest at the time of the test, but the margin of safety embodied in the test-pressure-to-operating-pressure ratio will be degraded with the passage of time for time-dependent flaws that are increasing in severity (i.e. their failure pressures are declining) with the passage of time. Therefore, as is the case with integrity assessment by means of ILI, the process should be repeated periodically to ensure continuing pipeline integrity. Guidelines for estimating the time interval between hydrostatic retests are presented in Section 10.
9.3.2 Hydrostatic Testing Limitations

Hydrostatic testing has some technical limitations. First, the only defects identified by a hydrostatic test are those that fail during the test. Flaws having failure pressures above the test pressure will not be discovered. This means that short, deep flaws (that have inherently high failure pressures, yet relatively short fatigue lives) could go undetected. Moreover, the operator gains no knowledge of the numbers and locations of flaws that have survived the test. Therefore, in establishing the time for the next integrity assessment by testing, one should assume that the failure pressure of the most severe remaining flaw is no higher than the test pressure, and that the flaw could be located anywhere within the segment. One should also be careful to use appropriate pipe properties in estimating the reassessment interval as high strength values, beyond the mill certification value, are common and can result in remaining flaws with short fatigue lives. Unless a large number of defects fail during the test, the pipeline operator learns little or nothing about the locations of potential flaws and problem spots where a line may be susceptible to phenomena such as corrosion, SCC, or pressure-cycle-induced fatigue. A history of hydrostatic tests and failures over time can provide some insight into problematic segments. Therefore, it is important to document where failures occurred, the cause of the failure, and the failure pressure.

The successive cycles of test pressure may cause other flaws to grow such that successive failures can occur at pressure levels below that of a prior pressurization (see pressure reversals in 9.3.6). While this phenomenon tends to prolong the testing process, adding to the cost, the impact of potential pressure reversals on pipeline integrity at the operating pressure is usually negligible. (See API TR 1179). Lastly, hydrostatic testing of a pipeline that has been in service is complicated by the need to interrupt liquid transportation service and by the difficulties in acquiring water for testing, and in disposing of the water once it has become contaminated by contact with a petroleum product or crude oil.

9.3.3 Minimum Test-Pressure-to-Operating-Pressure Ratio

Typical strength test levels are a minimum of $1.25 \times \text{MOP}$ and leak test levels of $1.1 \times \text{MOP}$. Where the test may approach SMYS, a yield plot should be performed to mitigate the potential for plastic yielding of the pipe wall. The selection of a minimum test pressure to operating pressure ratio for integrity assessments should be guided by API TR 1179.

9.3.4 Minimum Hold Time

Holding the test pressure at a constant level for a period of time is an appropriate method to detect leaks. Beyond the regulatory requirements, the length of hold time employed to assess for leaks should be based on the volume of water in the test section: the larger the volume, the longer holding at constant pressure is required to detect a leak of a given size. It should be noted that the value of hold time is solely that of establishing that the test segment is free of leaks. It does not add to the value of the test with respect to the margin of safety. Defects that are on the verge of failure at the test pressure may continue to grow during the hold period. If a growing defect fails, it is eliminated, and the hold period should be restarted. If no failure occurs during the hold period but one or more flaws grow without failing, the hold time has potentially made the defects worse. Since there is no way to determine the status of flaws that survive the hold period, the test pressure is the sole measure of the effectiveness of the test with respect to the margin of safety for operating the pipeline at its MOP.

9.3.5 High-pressure Integrity Test

Hydrostatic tests which are designed to address specific threats and verify that these threats are being managed by the integrity management system may be referred to as high-pressure integrity tests. The test pressure is typically greater than or equal to $1.25$ times MOP. It is not designed to qualify for a change in MOP but is an integrity management tool. See API TR 1179 for more details.
9.3.6 Spike Test

A hydrostatic pressure spike test is one that is conducted initially at a high-pressure level, relative to the operating pressure, held for a short time, followed by an extended hold period at a lower-pressure level. The spike portion of the test may or may not exceed the mill test pressure or a hoop stress equal to SMYS of the pipe, depending on the purpose of the test and the characteristics of the pipe.

It is only necessary to achieve and hold the high pressure for a short time to establish the integrity of the pipeline. The spike portion of the test must be held for a long enough time to assure that the pipeline has experienced a continuous pressure at or above the target level and to cause defects that are near critical (near the point of failure) to fail but not so long as to cause additional crack growth in flaws that are too small to be near the failure point (referred to as subcritical). Consistent with that objective, ASME B31.8S recommends a minimum period of 10 minutes. The effectiveness and value of the spike portion of the test is not improved by a longer period and extended hold periods at near-failure levels can be counterproductive.

The spike test is a variant of the hydrostatic proof test. Its purpose is two-fold: the spike portion of the test will induce failure in the pipe where significant defects may be present, while the subsequent relaxation of pressure allows any surviving cracks to stabilize and avoids subcritical crack growth during the hold period to detect leaks. For guidance on when a spike test is advisable, see API RP 1176.

One caveat with respect to conducting a spike test is that the test should not be terminated with a test failure. This may require lowering the target pressure level of the spike test to avoid another failure. Terminating a test with a failure greatly increases the chance that one or more surviving flaws will have a failure pressure less than the final level of test pressure achieved (see 9.3.7).

9.3.7 Pressure Reversals

The term “pressure reversal” is commonly used to describe the following situation which may occur repeatedly within a single hydrostatic test section. As test failures begin to occur, it is possible, that successive failures will occur at a pressure below a prior test failure. This phenomenon, commonly called a “pressure reversal” arises from the tendency for a flaw to grow by slow ductile tearing as the applied pressure approaches its failure pressure. If this growth is terminated just before the flaw fails because another defect in the test section fails, it is possible that the failure pressure of the just-surviving flaw will now be less than the pressure it has just survived.

Pressure reversals are common in hydrostatic tests of pipeline segments that contain families of defects having similar failure pressures. Generally, their impact on pipeline integrity at the MOP is negligible for two reasons. First, the potential size of a pressure reversal is inversely proportional to its likelihood. Secondly, in most cases where pressure reversals have been observed, the probability of a flaw being present that would fail at the MOP because of a pressure reversal is extremely small.

9.3.8 Detrimental Effects of Hydrostatic Testing

There are potential detrimental effects of hydrostatic testing, such as growth of sub-critical manufacturing and crack-like flaws, and these should be considered in the design of a hydrostatic test for integrity management purposes. Hydrostatic testing can also cause additional fatigue, shortening the segment’s service life. API RP 1110 and API TR 1179 describe some of these detrimental effects of hydrostatic testing.

9.3.9 Test Results Analysis

If no failures occurred during the hydrostatic test, then the test effectively determined that at the time of the test no leaks or injurious defects remained. A history of hydrostatic tests, pressure ratios, and subsequent failures can demonstrate the effectiveness of hydrostatic testing as an integrity management tool. A declining or stable rate of test failures or a decrease of in-service failures demonstrates hydrostatic test effectiveness.
Test failures should be investigated to determine their causes. The causes of failures will indicate the types of threats that are affecting the segment and their significance. The information on causes should be fed back into the data integration process and the risk assessment model to see if the segment needs to be reprioritized.

### 9.4 Other Assessment Methods

Technologies other than ILI or hydrostatic testing that could be used to assess pipeline integrity include “direct assessment” (applicable to external corrosion, internal corrosion, SCC, and possibly to mechanical damage-delayed failure) and guided wave ultrasonic technology (GWUT-applicable to external and internal corrosion). Visual inspection or other traditional nondestructive examination (NDE) methods [ultrasonic testing (UT), magnetic particle testing (MPT), liquid-penetrant testing (PT), etc.] can be used on excavated or above-ground piping. These methods offer ways of assessing for the time-dependent threats (excluding assessment to control a pressure-cycle-induced-fatigue threat) in pipeline segments that are difficult-to-pig (meaning that ILI is not reasonably feasible) or cannot be taken out of service, or both, to accommodate a hydrostatic test. Understanding the use of other assessment methods is important. The application of one or more of these technologies could suffice for assessing the integrity where applicable threats are limited. Each direct assessment methodology is designed to assess a specific threat. There are limitations when applying a direct assessment methodology to threats for which the method is not applicable. It is possible to use multiple direct assessment methods on a single segment where those methods each address the appropriate threat. Moreover, the direct assessment technologies can be usefully applied in conjunction with hydrostatic testing or ILI, particularly in conjunction with hydrostatic testing where little if any knowledge is gathered regarding the nature of the threat. For example, the application of SCCDA could help an operator decide whether an assessment for SCC is necessary.

### 9.5 Repair Methods

Anomalies exposed for direct examination on the basis of engineering critical assessments that are found to be injurious to pipeline integrity should be repaired by an acceptable repair method. Acceptable repair methods for a wide variety of defects are described in various industry standards and documents such as ASME B31.4, the PRCI Repair Manual, API RP 1176, and CSA Z662. Alternatively, the pieces of pipe containing injurious defects may be cut out and replaced with sound previously hydrostatically tested pipe (see Annex C). The tie-in welds for the replacement pipe should be radiographed or ultrasonically inspected. As a temporary mitigative measure or to protect personnel conducting a repair, the operator may choose to reduce the operating pressure of the pipeline. When a pressure reduction is employed to mitigate the effects of an anomaly, the time limit before a permanent repair should be made and calculated in accordance with the method shown in Annex D. Acceptable repair methods include but are not necessarily limited to:

- pipe replacement,
- full-encirclement split steel sleeves,
- steel compression sleeves,
- composite wrap repairs,
- mechanical clamps,
- deposited weld metal.

Annex C provides descriptions for several different repair strategies. The applicability of each of these repair strategies to the various types of anomalies can be found in several different industry standards and documents. Repair methods that might not be suitable for a permanent repair may be appropriate as a temporary repair. Note that pipe replacement is an acceptable permanent solution. For relatively shallow defects (defects that decrease the wall thickness by an amount equal to the manufacturing tolerance applicable to the pipe), removal by grinding, followed by nondestructive examination to ensure the absence of cracks, is an acceptable repair. Grinding and inspection to
ensure the absence of cracks is generally acceptable for defects up to 40% of the actual wall thickness, if the length of the ground-out area does not exceed the allowable length based on the maximum depth of grinding determined by ASME B31G.

Operators should consider the quality and material properties of a pipe’s ERW seam when conducting grinding operations.

10 Reassessment Intervals

10.1 General

Pipeline integrity assessment and remediation as described in Section 9 establishes the integrity of a pipeline segment at a given point in time. Some of the threats to pipeline integrity are time dependent as noted previously. Reassessment of the integrity of a pipeline segment subject to an anomaly growth mechanism should be carried out at appropriate intervals to minimize the risk of a pipeline failure caused by a flaw that was too small or was under the reporting size criteria detected in the last assessment. The appropriate interval for reassessment in the case of a time-dependent flaw growth mechanism depends on the failure pressures of the anomalies established by the most recent integrity assessment, an FPR less than 1.1, or the maximum calculated surge pressure of the pipeline, and the rates of growth of the flaws. Section 10 and Annex D provide guidance for pipeline operators in establishing representative growth rates and for calculating reassessment intervals. It is incumbent on the operator to confirm the applicability of the growth rates or methodologies that it is applying, realizing that circumstances associated with anomalous environments (e.g. high temperature, microbi ally induced corrosion (MIC), CP shielding) may lead to non-conservative results.

10.2 Anomaly Growth Rates

10.2.1 General

The pipeline operator should establish the actual effective growth rates for every growth mechanism that affects any segment that is to be considered for reassessment. Some techniques for determining growth rates are described below. Alternatively, if the operator cannot establish the actual effective growth rates, default rates may be available from other standards as explained below.

10.2.2 Linear Growth Rates

It is customary to assume that flaws created by external and internal corrosion and SSWC grow deeper linearly with time even though in reality these processes are likely to be intermittent. In other words, if the pit depth is \( d_1 \) measured at time \( t_1 \) and its depth increases to \( d_2 \) at a later time \( t_2 \), it is customarily assumed that the growth rate of the corrosion is \( \frac{(d_2 - d_1)}{(t_2 - t_1)} \) at that pit. An operator therefore may establish the actual effective rate of external or internal corrosion at the location of any given point where the particular phenomenon has occurred by comparing the depths of a pit as seen in two successive ILI runs after measurement errors are taken into account. Comparing a large number of pits in this manner may indicate a range of anomaly growth rates wherein the worst-case rate may be established from the distribution of rates with an appropriate degree of confidence. If only one ILI run is available or if only pit depth measurements made at specific locations are available, the 80% confidence level, worst-case anomaly growth rate can be established from the family of pit depths determined by the tool or by means of physical measurements taking into account measurement errors by a Monte Carlo simulation using an appropriate distribution of corrosion starting times. If the Monte Carlo technique is applied in the case where actual pit depths are determined from a few excavations instead of from ILI data covering the whole segment, the pit growth rate determined should be conservatively increased. Approaches can include increasing the growth rate by a factor of 2 or 3 standard deviations above the mean growth rate from the Monte Carlo estimate or doubling the mean growth rate.

Actual external corrosion rates at specific locations along a segment also may be determined by means of buried coupons or linear polarization resistance measurements. These measurements should be taken at sufficient locations to represent the corrosion conditions along the segment.
If the pipeline operator is not able to determine the actual effective rate of external corrosion, a credible default value may be selected using the criteria stated in ASME B31.8S-2010, Appendix B, Table B-1. Those criteria are reproduced in Table 4.

<table>
<thead>
<tr>
<th>Resistivity (from ASME B31.8S-2010)</th>
<th>Corrosion Rate mils/year</th>
<th>Soil Resistivity ohm-cm</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>&gt;15,000 and no active corrosion</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>1000 to 15,000 and/or active corrosion</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>&lt;1000 (worst case)</td>
<td></td>
</tr>
</tbody>
</table>

If the operator has not determined the actual effective rate, has no information concerning soil resistivity, and has reason to suspect that unusually aggressive corrosion mechanisms are present, such as stray currents or MIC, a default rate of 16 mils per year should be assumed (see NACE SP0502).

Actual internal corrosion rates at specific locations along a segment may be determined by means of coupons or electrical resistance change measurements taken through hot tap fittings. These measurements should be taken at locations where internal corrosion is most likely to occur along the segment (i.e. places where water and solids are likely to accumulate).

Periodic seam integrity assessments should be conducted for any segment that has experienced either an in-service or a hydrostatic test failure from SSWC. As in the case of external or internal corrosion, the rate of SSWC (external or internal) is customarily assumed to be constant (i.e. varies linearly with time). The rate of corrosion at the bondline of an ERW or FW seam will be higher than that of the immediately adjacent base metal if SSWC is occurring. The ratio of the corrosion rate in the bondline to that in the base metal is referred to as the “grooving” ratio, and grooving ratios as high as 4-to-1 have been observed.

If the segment is bare or poorly coated and is inadequately cathodically protected, susceptibility to SSWC should not be ruled out without additional supporting data. If deemed susceptible, a seam integrity assessment is needed. Whether periodic assessment is needed depends on the outcome of the seam integrity assessment. If pressure test leaks or test breaks occur because of SSWC anomalies or if SSWC anomalies are found by ILI, periodic seam assessment should be conducted. SSWC appears to occur irrespective of the operating stress level of the pipeline; therefore, even low-stress pipelines comprised of materials with susceptible seams should be investigated with respect to exposure to SSWC.

If the pipeline operator has no way to determine the actual effective rate of SSWC, a default rate could be based on the worst-case known rates of external and internal corrosion for the segment multiplied by the grooving ratio. If the grooving ratio is unknown, the pipe body corrosion rate should be multiplied by 4 to establish the rate for SSWC reflecting the highest grooving ratio that has been commonly seen in ERW line pipe materials that are susceptible to SSWC.

**10.2.3 Non-linear Growth Rates**

Fatigue crack growth and growth from environmental cracking are non-linear. API RP 1176 provides guidance on calculating growth rates for these threats.

Laminations have the potential to grow in the presence of hydrogen from CP systems or sour crude. Lamination growth from hydrogen is also referred to as hydrogen blistering or bulging. Growth rates for hydrogen blisters can depend on several factors including the hydrogen evolution rate, amount of hydrogen present and properties of the steel, and can be difficult to determine. One effective method to establish a growth rate can involve aligning data from
ILI and deformation tools to determine if internal bulging has occurred at a lamination and how much the internal deformation has changed between two ILI runs.

10.3 Establishing the Reassessment Interval

Generically, establishing a reassessment interval to deal with a time-dependent threat to pipeline integrity requires calculating the failure pressure of the worst-case flaw remaining in the segment after an initial assessment and determining the time it will take for the flaw to reach a size that will cause failure at the MOP. Calculating failure pressures require the use of a failure-pressure-versus-flaw-size model as discussed in Annex D. The time for the failure pressure of a growing flaw to decay from the benchmark value established by the last assessment to the MOP depends on the rate of growth. Since it is not prudent to allow this entire calculated time period to expire before carrying out a reassessment, a safety factor is embodied in the calculation.

The pipeline operator should establish the lengths and depths of the flaws that remain after an integrity assessment, and the amount of growth that could cause the FPR to decay to 1.1 as described above. The operator should also establish the rate of growth appropriate to the time-dependent growth mechanism as described in 10.2. For anomalies that are believed to grow at constant rates (i.e. linear growth over time) such as external corrosion, internal corrosion, or SSWC, the process described below may be used.

Consider that for long metal-loss defects having uniform depth equal to the maximum depth, given by Equation (1):

\[
FPR = \frac{P_{fail}}{P_{op}} = \left(\frac{t_{cor}}{t_{nom}}\right)\left(\frac{S_{flow}}{FS_{Y}}\right)
\]

where

- \(P_{fail}\) is the failure pressure,
- \(P_{op}\) is the pipeline design operating pressure,
- \(t_{cor}\) is the minimum corroded or remaining wall thickness,
- \(t_{nom}\) is the nominal or design wall thickness,
- \(S_{Y}\) is the pipe grade SMYS,
- \(S_{flow}\) is the flow stress usually taken to be \(S_{Y}+10\) ksi, and
- \(F\) is the design operating factor (e.g. 0.72).

Consider further a corrosion rate, \(CR\), measured or estimated in accordance with Section 10.2. The value of remaining wall thickness corresponding to a value of FPR is given in Equation (2):

\[
t_{cor} = (FPR)(t_{nom})\left(\frac{FS_{Y}}{S_{Y} + 10 \text{ ksi}}\right)
\]

The response time, \(T_{resp}\), is then the difference in time for the FPR to decrease from the value at the time of assessment, \(FPR_{ILI}\), to a critical value, \(FPR_{crit}\), due to an increase in \(t_{cor}\) divided by \(CR\) as given in Equation (3):

\[
T_{resp} = \left(\frac{FPR_{ILI} - FPR_{crit}}{CR}\right)\left(\frac{t_{nom}}{S_{Y} + 10 \text{ ksi}}\right)
\]

The minimum recommended value of \(FPR_{crit}\) is 1.1. \(FPR_{ILI}\) is determined using the first equation above and \(t_{cor} = t_{nom} - d_{ILI}\), where \(d_{ILI}\) is the depth of metal loss indicated by ILI. The response time varies with nominal wall thickness, SMYS, operating stress level, corroded wall thickness or repair criterion, and corrosion growth rate. Some illustrative examples are given below.
Consider a pipeline with nominal wall thickness of 0.250, design factor of 0.72, and pipe grade X52. ILI was performed and the operator elects to repair all features that would fail in a hydrostatic test to 100% of SMYS, so \( \text{FPR} = \frac{1.00}{0.72} = 1.39 \). Consider also a corrosion rate of 0.004 in./yr (4 mils per year). Then the response time would be calculated as shown in Equation (4):

\[
T_{\text{resp}} = (1.39 - 1.1) \left( \frac{0.250}{0.004} \right) \left( \frac{0.72(52000)}{52000 + 10000} \right) = 10.95 \text{ years}
\] (4)

If the operator instead elects to repair all features that would fail in a hydrostatic test to 1.25 times the maximum operating pressure, corresponding to a hoop stress of 90% SMYS, then \( \text{FPR} = 1.25 \) and \( T_{\text{resp}} = 5.75 \text{ years} \). This is shown in Figure 6. The response times for this same pipeline for corrosion features that have more metal loss resulting in lower FPR values can also be read off this curve. If the corrosion rate is 50% faster (6 mpy), the response time reduces to \( \frac{2}{3} \) of what it would be at 4 mpy (e.g. 7.3 years at the FPR of 1.39), as shown in Figure 6.

Consider a pipeline of having nominal wall thickness, pipe grade, and corrosion rate the same as the previous example but operating at only 55% of SMYS, or \( F = 0.55 \). Using the same repair criterion in which all indications with failure pressure corresponding to a hoop stress of 90% SMYS or lower would be repaired, \( \text{FPR} = \frac{0.90}{0.55} = 1.636 \), so response time is calculated in Equation (5):

\[
T_{\text{resp}} = (1.636 - 1.1) \left( \frac{0.250}{0.004} \right) \left( \frac{0.55(52000)}{52000 + 10000} \right) = 15.45 \text{ years}
\] (5)

Note that \( t_{\text{cor}} = 0.189 \) in, the same as the first example, because the repair criterion of 90% SMYS is the same. This shows that response time increases as operating stress decreases for the same amount of corrosion because a pipe operating at a lower stress can tolerate larger flaws. On the other hand, if the repair criterion is based on the indicated FPR equal to a test pressure of 1.25 times the maximum operating pressure, response time \( T_{\text{resp}} = 4.3 \text{ years} \). Thus pipelines operating at lower stress levels have reduced response time based on a given FPR because the lower-stress pipe can tolerate deeper flaws with less remaining wall thickness which then require less time to corrode to failure.

Consider the pipeline having the same wall thickness and design factor as in the first example, 0.250 in. and 0.72, respectively, but consisting of Grade B material with SMYS of 35 ksi. The operating pressure would be lower, commensurate with the lower grade SMYS. In that case, at a repair criterion of 1.39, response time reduces slightly to \( T_{\text{resp}} = 10.15 \text{ years} \) compared with 10.95 years for the X52 pipe. This is shown in Figure 6 as well.

As a final example, consider a pipeline having operating pressure the same as in the first case, but consisting of heavier-wall pipe due to it being a lower-strength material, Grade B with SMYS of 35 ksi. For a design factor of 0.72, \( t_{\text{nom}} = 0.375 \) in. (rounding up slightly to a standard wall dimension). At an FPR of 1.39, \( T_{\text{resp}} = 15.2 \text{ years} \) because of the 50% greater wall thickness.

The examples described herein indicate that a pipeline operator should establish assessment intervals for the specific circumstances of wall thickness, anomaly growth rate, MOP, and minimum failure-pressure-to-MOP ratio achieved by the current assessment in order to determine either when reassessment is needed or when it is necessary to remediate a particular anomaly. The process can be applied to corrosion-caused metal loss, SCC, and SSWC (i.e. to any time-dependent anomaly growth mechanism where it is safe to assume a constant anomaly growth rate). For each particular type of threat other than corrosion-caused metal loss in the body of the pipe the user should account for the effect of material toughness on the sizes of defects that will fail at particular benchmark pressure levels.

### 11 Preventive and Mitigative Measures

#### 11.1 General

The preceding sections, Section 9 and Section 10, are focused primarily on integrity assessment and reacting to what is found through integrity assessments to address the time-dependent degradation threats such as corrosion, environmental cracking, SSWC and fatigue growth of flaws. In addition to conducting integrity assessments, a pipeline operator should implement preventive and mitigative measures that reduce the probability of a release or the
consequences of a release from these time-dependent threats and from random (time-independent) threats such as third-party damage, equipment failure, and incorrect operations. Section 11 provides guidance for establishing and implementing preventive and mitigative measures to reduce the probabilities of releases and the consequences of releases from all threats.

The process of establishing and implementing preventive and mitigative measures begins with data gathering, data integration, and informational analysis as outlined in Section 7. Data integration and the analysis of the information developed through data gathering often reveal aspects of an operator’s operations and maintenance that allow the operator to address the threats to pipeline integrity and reduce the consequences of potential releases. The incident history associated with certain assets or circumstances should be considered. One or more incidents associated with any asset or circumstance may indicate the need for enhanced preventive and mitigative measures associated with the particular asset or circumstance. Some examples for prevention of each threat are shown in Table 5 and for mitigating consequences in Table 6.

In addition to their application to specific problems identified by data analysis and integration, preventive and mitigative measures are needed to address all threats to pipeline integrity, including those that can be assessed as described in Section 9 and Section 10. Threats that cannot be addressed by the previously discussed integrity assessment methods include:

- some manufacturing anomalies (hard heat-affected zones in ERW pipe),
- equipment failure,
- mechanical damage (causing an immediate failure),
- incorrect operations,
- weather and outside force (floods, landslides, subsidence, earthquakes, etc.).

The threat of mechanical damage causing an immediate failure and the threat of failure from weather and outside force are threats that potentially affect all pipelines. The threats of hard spots and hard heat-affected zones affect pipelines constructed with certain older materials that are susceptible to these phenomena. The measures for preventing and mitigating these are addressed in 11.2.1 through 11.2.3. In addition, Sections 11.2.4 and 11.2.5 present minimum requirements for preventing corrosion, and in 11.3 presents guidance for limiting consequences of pipeline releases by means of leak detection programs, flow restriction devices, and emergency response planning.
Lastly, Section 11.4 discusses the use of reducing operating pressure as a means to ensure pipeline integrity. The preventive and mitigative measures for the threats of equipment failure and incorrect operations can be defined based on data gathering as shown in Table 5. Prevention of equipment failure is a subject to be addressed in a pipeline operator's operating and maintenance procedures. Prevention of incorrect operations should be covered in a pipeline operator's operating procedures and operator training practices.

**Table 5—Examples of Preventive Measures to Address Pipeline Integrity Threats**

<table>
<thead>
<tr>
<th>Threat</th>
<th>Problems Identified through Data Gathering and Integration</th>
<th>Preventive Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td>External corrosion</td>
<td>Leak history; external ILI anomalies and/or low cathodic protection readings.</td>
<td>Conduct appropriate cathodic protection and/or stray current surveys. Increase cathodic protection.</td>
</tr>
<tr>
<td>Internal corrosion</td>
<td>Leak history, internal ILI anomalies; internal UT anomalies; increased corrosiveness of sampled transported fluids; analysis of pigging debris.</td>
<td>Conduct fluid sampling; performance of the corrosion inhibitor injection program; conduct an scraping/swabbing program. Run cleaning pigs more frequently.</td>
</tr>
<tr>
<td>SSWC, external or internal</td>
<td>Axially oriented anomalies identified with circumferential or helical ILI in a low-frequency ERW seam and low cathodic protection readings. Hydrostatic test failure.</td>
<td>Conduct appropriate cathodic protection and/or stray current surveys. Increase cathodic protection.</td>
</tr>
<tr>
<td>EAC</td>
<td>Ultrasonic crack detection or EMAT anomalies discovered in a pipe with tape wrap coating.</td>
<td>Increase cathodic protection on pipelines without shielding coatings. Reduce operating pressures and/or temperatures.</td>
</tr>
<tr>
<td>Manufacturing defects</td>
<td>Ultrasonic crack detection or EMAT anomalies discovered in pipe with a low-frequency ERW seam.</td>
<td>Reduce the magnitude and/or frequency of pressure cycles. Reduce the operating pressure.</td>
</tr>
<tr>
<td>Construction and fabrication defects</td>
<td>Defective girth weld found in a location with ground movement.</td>
<td>Run inertial mapping unit tool to find possible locations of ground movement.</td>
</tr>
<tr>
<td>Equipment failure</td>
<td>Seeps or stains in facilities at fittings or flanges. Increase frequency of inspections.</td>
<td>Replace gasket materials at specific intervals or when inspections indicate gasket deterioration. Develop flange torque procedures.</td>
</tr>
<tr>
<td>Mechanical damage with immediate failure</td>
<td>Near hits from landowners not making one-calls.</td>
<td>Install line-of-sight markers, trim right-of-ways more frequently, enhance contact with landowners, or establish agreements not to cultivate.</td>
</tr>
<tr>
<td>Mechanical damage with delayed failure</td>
<td>Alignment of ILI anomalies with geometric anomalies reveals locations of previous damage to pipelines.</td>
<td>Increase frequency of aerial and foot patrols in areas of frequent new construction.</td>
</tr>
<tr>
<td>Incorrect operations</td>
<td>Surges caused by poorly coordinated start-ups and unexpected shutdowns from power failures. Third Party valve operations.</td>
<td>Conduct advanced hydraulic studies to optimize start-up procedures and train opera-tors to use the new procedures. Install im-proved electrical gear at remote stations to minimize power outages.</td>
</tr>
<tr>
<td>Weather and out-side force related defects</td>
<td>River crossing inspections identify exposed pipe due to river scouring.</td>
<td>Install protective mats in some cases or replace crossings with directional drills.</td>
</tr>
</tbody>
</table>

**Table 6—Examples of Mitigative Measures to Address Consequences**

<table>
<thead>
<tr>
<th>Consequences</th>
<th>Mitigative Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contamination of drinking water aquifer.</td>
<td>Install hydrocarbon detection cable next to pipeline across the aquifer recharge area. Conduct spill drills aimed at rapid containment. Install monitoring wells.</td>
</tr>
<tr>
<td>Ignition of vapor cloud in populated area.</td>
<td>Educate the public as to the danger of a vapor cloud. Provide emergency phone number to residents. Increase frequency of ILI. Improve emergency response criteria.</td>
</tr>
<tr>
<td>A release results in large drain-down.</td>
<td>Install EFRDs. Increase frequency of ILI. Improve emergency response criteria.</td>
</tr>
<tr>
<td>Small leak over time accumulates into large release.</td>
<td>Improve leak detection; increase frequency of ILI; enhance patrol technology.</td>
</tr>
</tbody>
</table>
11.2 Prevention and Mitigation of Threats

11.2.1 Mechanical Damage

11.2.1.1 General

To protect a pipeline system from immediate failures caused by mechanical damage, a pipeline operator should establish a program to detect and prevent unauthorized encroachments on the right-of-way of the pipeline system. A damage prevention program should:

— maintain adequate, up-to-date maps of the system,
— participate in a one-call system,
— provide for timely temporary marking of any portion of the operator’s system that falls within the location scope of a one-call ticket,
— establish written guidelines for excavators authorized to work on the right-of-way stating and state what procedures an excavator should follow,
— provide a full-time observer while excavation is in progress on or in proximity to the pipeline,
— establish and continue a public awareness program with land occupants, excavators, and contractors,
— maintain adequate permanent pipeline-identifying markers along the right-of-way and trimming and mowing the right-of-way, where permissible, so that they remain identifiable and visible from the air,
— conduct periodic aerial and/or ground-based surveillance of all right-of-ways,
— install continuous markers or physical barriers where appropriate on new or reinstalled segments, or provide providing for deeper burial where appropriate,
— document all detected hits or near misses associated with either authorized or unauthorized encroachments on right-of-ways and investigating the causes for the hits or near misses,
— minimize impacts to critical locations.

See API RP 1166 for additional guidance on excavation monitoring and observation and API RP 1162 for guidance on public awareness programs.

Implementation of an effective damage prevention program requires adequate resources and adequately trained personnel to execute it. A pipeline operator should use qualified personnel that are responsible for the damage prevention program, and should provide the training necessary to ensure that they have sufficient knowledge and skills to understand the elements of damage prevention to be able to execute the program effectively. At a minimum, the damage prevention personnel should:

— be familiar with the pipeline system so that one-call tickets will be screened in a timely manner,
— be able to communicate easily with the appropriate one-call centers,
— be trained in locating underground facilities,
— be able to communicate with excavators, land occupants, emergency response personnel, and the public,
— be trained to monitor excavation and are familiar with the pipelines to which they are assigned,

— be familiar with pipeline surveillance techniques and have the opportunity to communicate with patrol pilots.

11.2.1.2 Mapping

A pipeline operator should create and maintain an up-to-date map of each pipeline facility. The maps of appropriate parts of the system should be provided to all one-call centers whose coverage includes those pipeline segments. Alternatively, the operator should indicate to all one-call centers covering regions containing segments of the operator’s pipelines, the “grid squares” through which those segments pass (see 11.2.1.3). Preferably, electronic maps should be provided which show each of the operator’s pipelines within a corridor of suitable width (e.g. 500 ft on either side of the centerline of the pipeline).

11.2.1.3 One-call Systems

States within the United States and many countries require operators of underground utilities to participate in a one-call system. The United States has established 811 as a nationwide one-call number. The purpose of the one-call system is to accept calls from potential excavators and to relay the location, scope, and time of the excavation to each utility having a facility located within a particular square of the grid covered by the one-call system (a typical grid square might be 1000 ft by 1000 ft). The information provided by the excavator is recorded on a document commonly referred to as a ticket. Copies of the ticket are sent to each of the participating utilities to notify them of the location, scope, and time of the excavation. Each notified utility is then responsible for locating and marking their facilities located within the square that could be affected by the excavation. A pipeline operator should participate in a one-call system in every area in which the operator has facilities. The operator should either indicate which of the system’s grids contain segments of the operator’s pipelines and/or supply the one-call center with up-to-date maps of the pipeline segments.

11.2.1.4 Locating and Marking

Upon receipt of a ticket from a one-call center, a pipeline operator should attempt to determine whether the excavation could affect one of the operator’s pipelines. If the operator is certain that the excavation will not encroach upon any of the operator’s facilities, the ticket should be “cleared,” that is, the operator should notify the one-call center that none of the operator’s facilities will be impacted or make contact with the excavator directly if the one-call center does not have positive response capability. If the excavation will be on or close to the operator’s right-of-way, the operator should promptly locate the pipeline that could be affected and mark its location with temporary markings. The markings should indicate the location of the centerline and size of the pipeline or the sides of the pipeline (or pipelines if it is a multiple-pipeline right-of-way). The operator should renew the markings if they become displaced by excavation or if they become degraded with the passage of time until all excavation activity has ceased.

11.2.1.5 Communication with an Excavator and Monitoring an Excavation

The pipeline operator, besides locating and temporarily marking the pipeline, should establish a communication link with the excavator that may involve the following:

— exchange of names of contacts and phone numbers;

— issuance of a written procedure for the excavator to follow that includes a distance-to-the-pipeline limit within which non-mechanical excavating techniques should be used, a description of how any exposed pipe should be supported, and a procedure for back-filling that will avoid damaging the coating on the pipeline or any cathodic protection attachments;

— agreement on a start time and the fact that the operator’s observer should be present when excavation is approaching within a specified distance of the pipeline.
Pipeline operators may obtain detailed guidance on how to monitor and observe excavations in API RP 1166.

### 11.2.1.6 Public Awareness

Although a potential excavator may not be aware of the dangers of excavating near a hazardous liquid pipeline, a pipeline operator should establish a public awareness program. Pipeline operators may obtain detailed guidance on how to establish and maintain a public awareness program in API RP 1162.

### 11.2.1.7 Right-of-way Maintenance and Surveillance

As a defense against unauthorized encroachments, a pipeline operator should clear the right-of-way of underbrush, tall weeds, trees, and canopy (where permissible). Keeping the right-of-way clear in this manner facilitates aerial surveillance, alerts land occupants and others to presence of a pipeline corridor, and increases the likelihood that anyone happening onto a right-of-way will see one or more permanent markers indicating the presence of an underground pipeline.

A pipeline operator should regularly conduct surveillance of each right-of-way, either by aerial patrol or other ways such as ground patrol. When using aerial patrols, operators should consider the use of a separate observer in addition to the pilot to improve the effectiveness of this type of right-of-way surveillance.

Alternatively, a pipeline operator may decide to patrol certain right-of-ways on foot or use of a vehicle.

### 11.2.1.8 Permanent Markers, Warning Techniques, and Physical Barriers

A pipeline operator should install permanent markers to alert anyone approaching a pipeline right-of-way that a pipeline is present. For guidance on the appropriate design of pipeline markers including where to put them and the types of information that should be provided on the markers, the operator should consult API RP 1109.

A pipeline operator may consider installing physical barriers such as concrete slabs above the pipeline to protect it. Alternatively, the operator may elect to bury a warning tape or plastic mesh above the pipeline to alert an excavator to the presence of a buried pipeline. These measures, if desired, can usually only be taken in conjunction with the construction of a new pipeline or the relocation of an existing pipeline. A pipeline operator may also consider lowering an existing pipeline by exposing and reburying it at a deeper depth. This may be necessary where a new road or railroad is being built over an existing pipeline. Another option is performing a depth of cover survey and proactively lowering shallow pipe in actively tilled land or areas where significant construction activity is occurring, planned or expected.

### 11.2.1.9 Documenting Hits and Near Misses

To determine which damage prevention techniques are the most cost effective, it is helpful to study and evaluate past mechanical damage hits and near misses. By understanding how these hits or near misses occurred, pipeline operators will be able to focus resources on the preventive techniques that are the most effective. In North America, the Common Ground Alliance has established a formal, but voluntary, damage incident reporting tool (DIRT). An operator of an underground facility who wishes to participate in this effort is asked to document each hit or near miss in conjunction with any excavation that takes place on, above, or immediately adjacent to the facility whether authorized or unauthorized. Analyses of these data have helped to identify when and how preventive measures either work as intended or fail to do their job. As this effort continues, it is reasonable to expect that pipeline operators will learn which preventive measures are the most effective.
11.2.2 Manufacturing Defects

11.2.2.1 Hard Spots and Hard Heat-affected Zones in Line Pipe

Pipeline operators have dealt successfully with round or oval hard spots in the body of the pipe by locating them with ILI magnetic tools and eliminating them or shielding them from cathodic protection. Currently, there is no ILI technique available that can locate the narrow hard zones adjacent to some ERW bondlines. Pipeline operators that experience the latter phenomenon generally had to bar the transport of sour crude or to monitor cathodic protection levels, and to limit them to levels that are adequate to prevent corrosion, but not so high as to generate excessive amounts of hydrogen at coating holidays.

11.2.2.2 Defective Pipe Seams

Pipeline operators can effectively manage longitudinal seam weld cracking by conducting periodic hydrostatic test assessments or inspecting pipelines with crack detection ILI tools, and performing excavations to repair cracks that might be service limiting. Operators can take measures to reduce the magnitude and/or frequency for pressure cycles as well as reevaluate pressure data on a regular basis to determine that no appreciable change in operation has occurred. If changes have occurred, the operator may need to conduct additional assessments or at a minimum, update remaining life calculations to reflect these operational changes. Additional guidance is provided in Section 16 of API RP 1176.

11.2.3 Weather and Outside Force Damage

A pipeline operator should attempt to prevent or mitigate the damage from weather events such as extreme cold, high winds, and flooding, and from geophysical events such as landslides, land erosion, or subsidence that could cause releases. Preventive or mitigative activities that an operator should consider are:

- inspecting drain valves and pipe extensions before cold weather arrives to eliminate water that will freeze and could cause breakage;
- monitoring river crossings for exposed pipe in crossings or at riverbanks;
- shutting down and, if feasible, purging pipeline segments that could be damaged by impending hurricanes or floods;
- providing for movement of the pipeline to occur without damaging the pipeline at seismic fault crossings, unstable slopes, or areas of subsidence;
- training patrol pilots to spot areas of developing soil instability, landslides, and subsidence;
- conducting patrols as soon as feasible after the passage of severe weather or flooding;
- routinely gathering updated GIS data regarding fault zones, land use, etc.

API RP 1133 provides detailed guidance for managing waterway crossings and hydrodynamic hazards under a risk-based approach.

11.2.4 External Corrosion

All buried steel pipelines should be protected from external corrosion by the installation of a protective external coating and an adequate cathodic protection system. NACE SP0169 provides minimum criteria for applying cathodic protection to mitigate external corrosion of a buried steel pipeline. Cathodic protection should also be applied to an existing pipeline whether it is coated or bare. Pipeline operators should follow NACE SP0169 regarding the minimum level of protection that should be maintained on an existing pipeline. Cathodic protection levels should be monitored.
at least once every 365 days. The levels of protection should be determined by making pipe-to-soil potential measurements at test leads typically located at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

At areas where the potentials fall below the levels indicated by NACE SP0169, the operator should investigate the cause of the low potentials and mitigate them. Mitigation should consist of bringing the cathodic protection levels into compliance with the levels specified in NACE SP0169 either by making sufficient repairs to the coating and/or by increasing the current outputs of existing anodes or adding anodes to increase the current output necessary to achieve the recommended levels. A pipeline operator may also find it useful to employ one or more of the ECDA techniques described in 9.4 to enhance the mitigation of external corrosion of a given pipeline segment.

Thermal insulation and some coating systems can decrease the effectiveness of CP systems. In addition, elevated temperatures can increase corrosion growth rates and the cathodic potential required to inhibit corrosion.

Induced AC corrosion has become better understood and should be controlled. For information on mitigating induced AC corrosion, see NACE 35110 and NACE SP0177.

Similar prevention and mitigation methods as discussed for external and internal corrosion can also be applied for SSWC of ERW seams such as installation of a protective coating and an adequate cathodic protection system for external corrosion.

11.2.5 Internal Corrosion

If the fluid being transported in a pipeline has the potential to corrode the internal surface of the pipeline, the operator should determine the nature of the corrosion that could occur and should take adequate steps to mitigate it. The most common form of internal corrosion arises in conjunction with the holdup of water or the deposition of sediment, or both. These phenomena are functions of the fluid characteristics and the flow velocity, and the elevation profile. The operator can monitor critical locations by installing coupons or resistance-change devices, or by measuring wall thickness to detect loss of metal. Mitigative steps include:

— injecting or batching a suitable chemical control,
— frequently cleaning with cleaning pigs to remove sediment and water,
— maintaining a flow velocity to entrain water and sediment,
— flushing dead legs or valve bodies,
— preventing oxygen ingress to the pipeline by careful control of non-standard operations.

A pipeline operator may also find it useful to employ one or more of the internal corrosion direct assessment (ICDA) techniques described in 9.4 to enhance the mitigation of internal corrosion of a given pipeline segment. See also NACE SP0208 and NACE SP0106.

11.2.6 Environmentally Assisted Cracking

11.2.6.1 Stress Corrosion Cracking

Pipeline operators effectively manage SCC by conducting periodic hydrostatic test assessments or inspecting pipelines with crack detection ILI tools and performing excavations to repair cracks that might be service limiting. Other preventive measures may include improving or upgrading cathodic protection systems for lines that do not contain a shielding coating like polyethylene tape or shrink sleeves, reducing operating temperatures, or reducing the operating pressure. Additional guidance is provided in Section 16 of API RP 1176.
11.2.6.2 Hydrogen-induced Cracking

Hydrogen-induced cracking (HIC) can occur in hard spots or at internal discontinuities such as laminations or large inclusions. Controlling the amount of hydrogen present (i.e. adequate CP system control) in the environment and eliminating hard spots (see 11.2.2.1) can be used to prevent or mitigate HIC.

11.2.6.3 Sulfide Stress Cracking

Pipelines that transport wet, sour products or are in other sulfidic environments can experience sulfide stress cracking (SSC). Therefore, methods to prevent SSC include removing moisture from sour products, lowering the sulfur content of such products, reducing operating stress levels, or locating and removing materials with hard microstructures.

11.2.7 Construction and Fabrication Defects

A pipeline operator can prevent construction and fabrication related defects by having an effective quality management system in place during construction that focuses on planning, specifications, proper installation procedures, inspections, documentation, and continuous improvement. API RP 1177 details how to create and manage a quality management system for new construction.

Where construction and fabrication defects may enter service, prevention and mitigation measures may include above-ground surveys to detect locations of coating damage or monitoring for locations with high axial stress.

11.2.8 Equipment Failure

Prevention or mitigation measures for equipment can include regular visual inspections for corrosion, leaking gaskets, leaking seals, stripped threads, and valve packing leaks. Specific equipment components that experience wear and tear, such as bearings and seals, should be placed on a preventative maintenance schedule. Ultrasonic and radiographic wall thickness measurements can also be combined with visual inspections to monitor for corrosion on certain pieces of equipment such as dead legs, drain lines, relief lines, and at supports and hangers. Operation of mainline valves and overpressure protection devices should also be verified on a regular basis.

11.2.9 Incorrect Operations

Prevention and mitigation measures for incorrect operations can include employee and contractor training and qualification to ensure they are technically qualified to perform the work for which they are assigned. Refresher training as well as regular dissemination of the causes of near miss or incident reports can also serve as a way to reduce incidents related to incorrect operations. Robust procedures that are updated on a regular basis, followed by training of personnel, and simple to use systems will facilitate proper use by employees and contractors.
11.3 Mitigating the Consequences of Unintended Releases

11.3.1 General

An IMP should contain protocols for detecting leaks and for limiting the consequences in the event of an unintended release. Elements of the plan should describe the methods and procedures for:

- minimizing the time required for detection of a release,
- minimizing the time required to locate a release,
- minimizing the volume that can be released,
- minimizing emergency response time,
- protecting the public and limiting adverse effects on the environment.

API RP 1130 and RP 1175 detail leak detection programs and methods.

11.3.2 Reducing the Time to Detect and Locate Unintentional Releases

A pipeline operator should select, install, and maintain a leak detection system or systems appropriate for the length and size of the pipeline, the type of products within the pipeline, and the spill scenarios for critical locations developed in Section 6. The abilities to detect a leak of a certain minimum size and to locate where such a leak has occurred depend on the type of leak detection system or systems employed. The leak detection methods and their characteristics are summarized in Table 7. Brief descriptions of leak detection methods are presented below.

A pipeline operator may find it advantageous to employ a combination of these methods. For example, the computational methods could be augmented by a volume balance approach or tracer chemicals or a stand-up test, or a combination thereof, could be used on occasion as a check on the real-time methods. In any case all real-time leak detection systems should be tied to the SCADA system, and the operating personnel should be well-versed as to the nature, characteristics, and operation of each leak detection system.

11.3.2.1 Isolation and Control of a Release

If a release is suspected or has been confirmed, the pipeline should be shut down. An exception to this would be leaving a pump station in operation if it is pulling product away from the release site. Shutting down the system and/or pumping product away from the release limits the subsequent volume of the release to the gravity drain-down volume (or vaporization of a HVL). The pipeline operator should locate and isolate the release as rapidly as possible to further limit the quantity of the release by minimizing gravity drain-down (or the size of the vapor cloud in the event of the release of an HVL).

Manually closing block valves may aid in limiting the gravity drain-down volume. Operators should consider installing block valves or check valves in appropriate locations to minimize spills. Emergency flow restriction devices such as remote control valves, automatic valves, or check valves can be employed to further limit the gravity drain-down volume. Automatic valves should be employed only in situations where normally expected transients will not cause them to close when there is no leak.

It should be noted that adding additional valves to a pipeline right-of-way may increase the risk of certain threats such as pipeline overpressurization during rapid valve closure or the risk of leaks from improperly installed or maintained valves. The potential increase in risk associated with the addition of new valves should be considered in a manner consistent with considering other risk factors.
### Table 7—Leak Detection Methods

<table>
<thead>
<tr>
<th>Method</th>
<th>Locates Leak</th>
<th>Availability</th>
<th>Beneficial Feature</th>
<th>Biggest Limitation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Periodic auditory, visual, and olfactory inspections</td>
<td>Yes</td>
<td>Periodic</td>
<td>Simplicity</td>
<td>Delayed recognition of leak between intervals</td>
</tr>
<tr>
<td>Volume balance</td>
<td>No</td>
<td>Intermittent based on comparison time</td>
<td>Simplicity</td>
<td>Transients tend to cause false alarms</td>
</tr>
<tr>
<td>Dynamic flow modeling</td>
<td>Yes, if analysis is done</td>
<td>Continuous even when transients are present</td>
<td>Best method to detect small leak rapidly</td>
<td>Complexity and cost</td>
</tr>
<tr>
<td>Tracer chemical</td>
<td>Yes</td>
<td>Can be either continuous or one time</td>
<td>Accurately locates small leaks</td>
<td>Must add something to the product and requires air sampling</td>
</tr>
<tr>
<td>Release detection cable</td>
<td>Yes</td>
<td>Continuous</td>
<td>Accurately locates small leaks</td>
<td>Next to impossible to retrofit to an existing pipeline</td>
</tr>
<tr>
<td>Shut-in leak detection</td>
<td>No</td>
<td>Periodic</td>
<td>Simplicity</td>
<td>Requires shutting off flow and accurate pressure monitoring</td>
</tr>
<tr>
<td>Pressure point analysis</td>
<td>Yes, if multiple points used</td>
<td>At the sampling rate except during transient operation</td>
<td>Simplicity</td>
<td>Not suitable for large pipelines or compressible fluids</td>
</tr>
<tr>
<td>Acoustic leak detection</td>
<td>Yes</td>
<td>Continuous</td>
<td>Direct measurement of leak location and rate</td>
<td>Implementation complexity and cost</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Periodic</td>
<td></td>
<td>Operational restrictions</td>
</tr>
</tbody>
</table>

11.3.3 Emergency Response

The operator should implement a response management system that provides a sufficient and timely response to releases and spills. The operator’s response management system should include:

- response planning requirements (including response plans and planning during response);
- training and drills;
- response activation (including discovery, internal and external notifications, and resource mobilization and deployment);
- performance measures;
- consider equipment, spares, material, consumables etc., strategically located near a pipeline needed to cover a leak or rupture scenario,
- continual improvement.

**NOTE** The operator may receive notice of a release or spill from a variety of sources, including leak detection systems, notification by field personnel, reports from the public, or other third-party sources.

Operators of onshore hazardous liquid pipelines (including operators of pipelines that transport highly volatile liquids) should refer to API RP 1174 and applicable regulations for guidance on emergency response management systems, planning, training, and activation.
11.4 Reducing Pressure

A reduction in operating pressure can be used to lower the risk associated with threats to pipeline integrity that are hoop stress related (i.e. corrosion-caused metal loss, SCC, SSWC, mechanical damage, or the growth of a flaw through fatigue). A pressure reduction can be either permanent or temporary. If operators are unable to meet repair or reassessment deadlines, they should implement a temporary pressure reduction. If an operator chooses to employ a pressure reduction, the amount shall be determined in the same manner as discussed in Section 9.

12 Integrity Management of Facilities

12.1 General Considerations

Integrity management can be more complex for facilities than for mainline pipe due to the different functions that facilities serve and to the variation of equipment in service. Because the piping and operation of facilities are distinctly different from that of mainline pipe, the threats at facilities such as pump stations, terminals, and loading facilities are characterized and grouped in a different manner than they are for mainline pipe. Experience suggests that facilities incidents typically involve small volume releases that are contained on site. Large-volume releases (greater than 50 barrels) in facilities are less likely. The attributes of facilities piping that distinguish it from mainline piping and the need to be considered in the management of its integrity are:

— relatively low operating stresses, except downstream of pump discharge or at booster stations,
— multiple types and sizes of piping and tubing,
— smaller sizes of pipe often joined by non-welded fittings,
— branches of the system that are used infrequently leading to low or intermittent flow,
— the majority of the system installed above ground on supports,
— above-ground and below-ground piping sometimes covered with insulation,
— piping configurations that result in “trapped space” i.e. dead legs where water may accumulate,
— difficult to inspect and unpiggable piping,
— the location within a facility where access is controlled by the operator and often protected with secondary containment.

12.2 Facility Threat Assessment

12.2.1 Facility Piping and Equipment Threats

The hazardous liquids industry’s pipeline performance tracking system (PPTS) has studied facilities piping and equipment releases and several advisory bulletins have been issued. These advisory bulletins, which identify the
primary threats to facilities piping and equipment include but are not limited to:

— external corrosion at supports or hangers, at soil-to-air interfaces, corrosion under insulation (CUI), CP interference;

— internal corrosion from trapped water or sludge particularly with crude oil-types of piping most susceptible are drain lines, relief lines, low points, intermittently used facility lines, stub lines, and “dead legs” that experience low or intermittent flow of product;

— internal erosion and corrosion/erosion;

— environmental cracking associated with the transport of fuel grade ethanol and SCC;

— manufacturing defects including seam and equipment body defects;

— construction and fabrication defects including installation girth weld failures;

— equipment failure including pump seal, packing, gasket, and o-ring failures, control or relief equipment failures, external fitting leaks; improper support of piping spans, flanged or other connection leaks;

— mechanical damage and vandalism causing an immediate or delayed failure;

— incorrect operations including overpressure from transients or thermal effects, tank and sump overfills, incorrect valve positions, improperly installed equipment or fittings in small bore tubing and pipeline (<2 in. nominal pipe size), operator errors;

— weather and outside force defects including freezing of trapped water, potentially from hydrostatic testing, in fittings or small diameter piping (especially <3 in. nominal pipe size), ground movement, and settlement.

There are several techniques that can be used to identify threats at a particular facility including SME based identification, checklists, Hazard Identification (HAZID), Hazard and Operability Study (HAZOP), What-If Analysis, reliability centered maintenance (RCM), and failure modes, effects, and criticality analysis (FMECA).

More detailed descriptions of the facility piping and equipment threats are provided in Annex G.

12.2.2 Time Dependent Interactions

Operational or environmental conditions can act on resident features in facility piping or equipment to cause degradation over time. For example, some of the facility piping and equipment threats listed in 12.2.1 can experience fatigue from vibration, thermal cycling, or pressure cycling which needs to be considered as part of a facilities integrity management program.
12.3 Gathering, Reviewing, and Integrating Data

12.3.1 Data Elements

The types of data that are useful for integrity management of facilities include but are not limited to:

- Scope of facility integrity management program;
- Type of facility (pump station, metering, storage, mainline valve, etc.) and its location;
- Products transported or stored;
- Piping and Instrumentation Diagrams (P&IDs) and Process Flow Diagrams (PFDs);
- List of equipment and piping, including location, age, material of construction, and construction documents (MTRs, NDT reports, pressure test records);
- Throughput and storage capacity;
- Operating conditions including design limits, product corrosivity (including impurities), operating history;
- Inspection and maintenance history including monitoring locations, repair history, maintenance and inspection records, pressure test records;
- Failure history (incidents and near misses).

The pipeline operator should conduct a thorough review of the incident history of the facility and of facilities with similar designs and characteristics. Operators should also consider industry incident history such as the PPTS Operator Advisory 2009-5, NTSB Reports and PHMSA Advisories. The focus of mitigative actions to prevent releases at facilities should be on the highest threats that are known to have caused releases in the past. In addition, any near misses or incidents that required repairs to facilities and reconstruction of certain components should be studied. Lastly, other common facility incident causes that have not caused failures or near losses but are probable for a facility should also be considered.

12.3.2 Data Integration

Data integration is the process of combining multiple pieces of information to gain a better understanding of overall facility integrity. Examples of data integration for managing integrity for pipeline are provided in 7.3. AlthoughILI is not regularly conducted for facility piping, the results from NDE can be integrated with knowledge about facility cathodic protection effectiveness, evidence of corrosion from visual inspections, operating temperatures, low-flow locations, and product corrosivity to indicate where the corrosion threat might be more severe. Data from routine equipment inspections can also be integrated with operational knowledge to determine where threats may be more severe from vibration, wear, improper installation, and mechanical damage.

12.4 Facility Risk Assessment

A general approach for facility risk assessment should start with high level screening to prioritize facilities by top integrity-related threats, consequences, or risk scenarios. Example parameters that can be used for the screening process include tank sizes, throughputs, product types, proximity to populations or sensitive environmental areas, and business impacts. After all facilities are evaluated with a high-level screening, this can be followed by a more detailed, facility-specific risk assessment to prioritize where assessments or routine maintenance is needed, and how often. Example facility-specific risk factors include severity of service, flow rates, frequency of usage, low points, prior failure history, inspection coverage and frequency, knowledge of piping or equipment condition from inspections, credible damage mechanisms, and rate of deterioration.
Facility risks differ from pipeline risks since most equipment and piping is above ground and may operate at lower pressures; similar risk assessment methods as discussed in 8.2 can be applied to determine facility risk. Characteristics of these risk assessment approaches are discussed in 8.3 and are also relevant, except that facilities are fixed locations rather than linear assets like pipelines.

12.5 Facility Integrity Assessment

With a multitude of approaches for facility integrity assessment, it is important for operators to develop a standardized approach to inspection practices for use throughout their facilities. The initial step, as discussed previously, is for operators to identify and document the threats that may be present as well as potential threats so that the operator can effectively manage the integrity of individual circuits or systems within a facility. Systems that can be susceptible to multiple threats may require multiple integrity assessments to fully evaluate the integrity. As inspection technologies improve with time, operators are encouraged to evaluate and adjust their inspection program. Appropriate measures should be taken upon discovery of threat severity, consistent with established practices as well as any regulatory requirements.

One example of a systematic approach that could be used by the operator is to develop inspection isometric schematics. These schematics can be used to inventory the facility piping operating characteristics and pipe properties, and equipment circuits as well as help identify the risk reduction opportunities based on inspection technology capabilities coupled with inspection frequencies.

More thorough guidance is available in documents such as API 570, API 2610, and API 2611. Operators should conduct periodic visual and NDE to ensure that necessary elements of a facility are inspected. Elements to be considered for inspection at recurring intervals should include the following:

— Valves and flanges:
  — Review valve and flange leak history;
  — Examine for signs of leakage such as stains;
  — Examine studs and nuts for looseness or corrosion; torque nuts to manufacturer specifications;
  — Ensure threads extend through and beyond nuts;
  — Ensure flanges are aligned according to procedures;
  — Examine gasket condition;
  — Confirm that buried flange connections are not leaking.

— Threaded, compression, or flared fittings:
  — Examine for signs of leakage, misalignment, corrosion, or mechanical damage; and
  — Ensure that the piping schedule (wall thickness) of threaded nipples provides adequate structural integrity.

— Vibration:
  — Examine for observable oscillation;
  — Examine for excessive overhung weight;
— Evaluate for inadequate support;
— Examine for loose supports that could cause metal wear.

— Dead legs:
— Eliminate, isolate, or drain identified dead legs, if possible;
— Purge with nitrogen;
— Ensure that an established and periodic flushing procedure is followed;
— Develop a method to assess the integrity of the dead leg (e.g. wall thickness measurements).

— Drain lines and relief lines:
— Measure wall thickness at low spots;
— Purge water from low spots each year before start of freezing weather;
— Verify buried piping has adequate CP;
— Where feasible, flush with product, potentially containing inhibitor or biocide, or both.

— Supports:
— Examine for missing shoes;
— Examine for hanger distortion or breakage;
— Evaluate brace distortion or breakage;
— Tighten loose brackets;
— Examine for metal wear or corrosion at support contact.

— Coating:
— Examine for general coating or paint deterioration;
— Evaluate soil-to-air interface for missing or deteriorated coating.

— Insulation:
— Evaluate for damage or penetrations;
— Note and correct missing jacketing or insulation;
— Replace deteriorated end seals;
— Examine for bulging, sagging, and buckling;
— Repair broken or missing banding.
— Casings:
  — Modify both ends of the casing extending beyond the ground line, if practical;
  — Verify that the pipe and casing are not metallically shorted.
— Signs of leakage or seepage.

In addition to these scheduled external inspections by inspection personnel, other personnel who frequent the facility should be observing and reporting deterioration, changes to the facility, or other irregularities.

12.5.1 Visual/Surveillance

External visual/surveillance inspections are performed to assess for abnormal physical conditions of a facility such as missing or degraded insulation, deteriorated coating, misalignments, evidence of corrosion, excessive vibration, and leakage. An operator may choose to incorporate visual inspections of specific facility equipment on a monthly or more frequent basis per API RP 570.

Regularly Scheduled Walkaround—Typically consists of a visual inspection using a predefined list of equipment or tasks to capture the physical condition of the facility. Items on the list may include observations of rotating equipment, pipe supports, air-to-soil interface coating condition, vibration, leaks, misalignment, paint condition, and tank appurtenances.

Focused Visual Walkarounds—Typically, the inspection is performed by a certified ASNT level inspector, and a formalized report is provided that describes the various individual facilities and descriptions of their physical condition, including photographs. An example of this type of report is provided in Annex H.

12.5.2 Leak Detection

When selecting a leak detection technology and establishing programmatic drivers, an operator should consider various factors which include objectives, monitoring capabilities, leak repairs, environmental reporting, and understanding the technology’s capabilities and limitations. Each leak detection system should be evaluated based on the following:

— sensitivity to small leaks;
— accuracy in distinguishing leaks from spurious signals;
— reliability to identify leaks for many years without maintenance or calibration;
— robustness to withstand adverse conditions;
— adaptability to many environments;
— detection limitations.

An operator’s response to potential releases should be based on these parameters. Common leak detection approaches are discussed in the following paragraphs.

Tracer Gas—This methodology uses specifically tuned detection equipment that is sensitive to trace amounts of an inert chemical not otherwise found at the facility which is added to the product at low concentration levels. Tracer gas detection is accomplished by sampling vapors with probes placed throughout the facility or by using handheld units during facility walkthroughs. Since the probes are dispersed along facilities, detection of a leak at a specific probe(s) can also help pinpoint its location. This method can be used during normal operation and does not require service
interruption while the test is being performed. A variety of tracer gas inoculations can also be used to differentiate which component might be leaking.

Cameras—Various types of specialized video cameras can be used at facilities to monitor operations and identify leaks but generally require humans to view and interpret the video images. Specific gases such as hydrogen, methane, carbon monoxide, and carbon dioxide can be detected by optical gas imaging (OGI) cameras where a leaking gas plume appears in real time as a smoke-like cloud from the leaking components. In addition, escaping hot gases and local cooling caused by expansion of gases from high-pressure systems can be detected by infra-red (IR) cameras. Factors that could affect the recorded IR image include temperature difference between vapor and background, and distance between the camera and plume source. A protocol for consistent and qualitative OGI surveys has been developed in the Netherlands (Standard NTA 8399).

Acoustic Techniques—As a pressurized system leaks, acoustic energy is emitted that can be detected by sensors in the vicinity of the leak. Acoustic leak detection systems typically use piezoelectric sensors. Sensor tuning and digital signal processing are needed to detect low amplitude leak signals in the presence of more dominant facility noise. This method is not intended to determine leak size but rather is used as a qualitative technique (e.g. a leak is occurring). The system can be susceptible to interferences from mechanical noise (grinding, welding, impact wrenches, compressors, pumps etc.) or electrical noise, and these phenomena could affect the sensor’s sensitivity. See ASTM E1211/E1211M-12, Standard Practice for Leak Detection and Location Using Surface-Mounted Acoustic Emission Sensors.

Liquid Hydrocarbon Monitors—Fiber optic cable systems detect leaks by monitoring for changes in light transmission properties in the presence of hydrocarbons that contact the cable. Cables must be strategically placed near valves, flanges, pipes and other components with the potential to leak. Another method involves hydrocarbon vapor monitoring sensors at sumps, catch basins, and underground monitoring wells. These two methods directly detect liquid hydrocarbon leaks without the need for tracer gases, temperature changes, or acoustic emissions.

12.5.3 Screening Assessments

Guided Wave Ultrasonics (GWUT)—The GWUT method is used to inspect a length of pipe for corrosion and other anomalies with significant circumferential extent. This method is most useful where the pipe is difficult to directly access such as at road crossings, tank dike penetrations, transitioning from above ground to below, penetrating walls or structures, and at pipe supports.

The methodology sends a full circumference ultrasonic (UT) wave through the pipe in the axial direction to detect changes in cross sectional areas of piping (internally or externally). While quantitative measurements of area are provided, this method is considered as a screening method since the length and depth dimensions of corrosion anomalies are not provided in sufficient detail to perform accurate integrity assessments. Other places where GWUT can be used are on above ground locations where full inspection coverage is desired. Screening by GWUT is first applied and then followed up by more specific inspection tools such as radiography, automated ultrasonic testing (AUT), laser scanners, or EMAT to quantify the feature(s) called out by GWUT. One limitation of the technology is that it is not able to detect pin-hole sized metal loss.

Inspection systems use many methods to generate UT waves and listen for the return energy from anomalies including piezoelectric, magnetostrictive, and EMAT. Each system has unique advantages and limitations including resolution of small anomalies and inspection range along the pipe. Inspection range can also be affected by attenuation of the GWUT signal, which can be attributed to coating type, pipe diameter and wall thickness, girth welds, bends, fitting, branch connection, and product in the pipe. For pipe with a thin coating, uniform girth welds, and no fittings or obstructions, an inspection range of a few hundred feet is possible. Some combinations of factors limit inspection range to tens of feet.

There are four references that provide guidance on use of GWUT technologies:
1) ASME Boiler and Pressure Vessel Code (BPVC) Section V, Article 19, Guided Wave Examination Method for Piping

2) BS 9690-1\&2, Non-destructive testing-Guided wave testing

3) ASTM E2775, Standard Practice for Guided Wave Testing of Above Ground Steep Pipework Using Piezoelectric Effect Transduction

4) PRCI Catalog No PR-306-123740-R01, Comparative Analysis of Pipeline Inspection Technologies Using Guided Waves and Ranges of Applicability

Direct Assessment (ACVG/DCVG/CIS/Current Attenuation Survey)—Many of the direct assessment processes used for line pipe can also be applied to facilities. The focus of an ECDA, ICDA, or SCCDA is to identify more probable locations of external corrosion, internal corrosion, or SCC. The direct assessment process can be applied for multiple facility integrity threats by integrating knowledge of the physical characteristics and operating history of a pipeline with the results of diagnostic and direct measurements performed on the pipeline or equipment. A detailed description of the direct assessment process is available in Annex E.

12.5.4 Direct Inspection Techniques

Several direct inspection techniques exist to quantify features that can affect the integrity condition of the piping circuits in a facility. Each technique has advantages and disadvantages that the operator must consider while planning an inspection. Multiple inspection techniques may be required to accurately assess the integrity condition of a circuit. The integrity inspection plan should be assessed prior to commencing the job at each site. An operator is encouraged to analyze and define the potential integrity threats that may be encountered so that the inspection instruments selected are appropriate to assess the facility. Techniques on how to perform such tasks are described in API 570, API RP 571, API RP 574, API RP 577, and API RP 2611. These techniques coupled with a robust risk-based inspection (RBI) methodology can form an operator’s risk managed inspection program. API RP 580, API RP 581, and ASME PCC-3 are recommended practices that can guide an operator through RBI techniques. A complete inspection equipment list can be reviewed from ASME BPVC Section V, Table A-110 Imperfection vs Type of NDE Method. Examples of inspection techniques that can be used are provided in Table 8, with hydrostatic testing included at the end for comparison.

12.5.5 Repair Methods

Facility operators should identify the features that require repair as well as determine the extent and timing of a response. Acceptable repair methods for a wide variety of defects are described in Annex C and industry standards and documents such as API 570, ASME B31.4, the PRCI Repair Manual, API RP 1176, and CSA Z662. Fitness for service methods to determine response timing include RSTRENG, Modified B31G, or methods described in API 579.

12.6 Reassessment Intervals

12.6.1 Scheduling Based on Threats

Section 10 and Annex D provide detailed information on anomaly growth rates and determining reassessment intervals. The same methodologies can be applied to facilities. Other useful references for determining growth rates and reassessment intervals include API RP 1176, API RP 2611, API 580, API 581, and API 570.
### Table 8—Direct Inspection Methods Applicable to Facilities

<table>
<thead>
<tr>
<th>Technique</th>
<th>Typical Applications</th>
<th>Advantages</th>
<th>Limitations</th>
</tr>
</thead>
<tbody>
<tr>
<td>UT—thickness gauging</td>
<td>Measures wall thickness. Attenuation and velocity changes in acoustic wave assist in evaluation of materials properties and in-service damage.</td>
<td>— Direct measurement &lt;br&gt; — Quick &lt;br&gt; — Can be combined with a scanner to produce and image (AUT)</td>
<td>— Requires a liquid couplant &lt;br&gt; — Surface must be smooth &lt;br&gt; — Limited coverage proportional to the size of the probe</td>
</tr>
<tr>
<td>UT—flaw detection (shear wave, angle beam, time-of-flight diffraction (TOFD))</td>
<td>Quantifies and qualifies anomalies such as cracks, crack-like, non-fusion, and slag.</td>
<td>— Direct measurement &lt;br&gt; — Quantifies flaw size</td>
<td>— Requires a highly trained inspector &lt;br&gt; — A slow process that can be costly &lt;br&gt; — Laminations can hide features or cause a false positive call.</td>
</tr>
<tr>
<td>Radiography</td>
<td>Detection of cracks, voids, inclusions, thickness changes, lack of fusion, incomplete penetration, and corrosion.</td>
<td>— Direct image of flaw (size and location) &lt;br&gt; — Permanent record &lt;br&gt; — Simple interpretation &lt;br&gt; — Applicable to many materials</td>
<td>— Radiation hazard &lt;br&gt; — Orientation of flaw affects detection &lt;br&gt; — Difficult to apply on complex parts &lt;br&gt; — Defect volume (planar vs volumetric) &lt;br&gt; — Thickness and pipe diameter limitations</td>
</tr>
<tr>
<td>Direct Magnetic Particle Inspection (MPI) or Liquid Dye Penetrant Inspection</td>
<td>Finds narrow surface breaking discontinuities, cracks, or porosity.</td>
<td>— Relatively inexpensive &lt;br&gt; — Fast and simple to use</td>
<td>— Only finds surface breaking features &lt;br&gt; — Depth not provided &lt;br&gt; — Requires good illumination and a clean surface</td>
</tr>
<tr>
<td>Direct Electro-Magnetic Acoustic Transducer (EMAT)</td>
<td>Locates and qualitatively assesses wall loss, corrosion under supports, air-to-soil interfaces, mill related features, cracks, and coating disbondment</td>
<td>— Fast screening tool &lt;br&gt; — No liquid couplant needed</td>
<td>— Requires a highly trained inspector &lt;br&gt; — Wall thickness must be less than ( \frac{3}{4} ) in. &lt;br&gt; — Flaw detection sensitivity usually lower than conventional UT</td>
</tr>
</tbody>
</table>
Laser Scanning
Maps metal loss areas as well as dents with and without metal loss.
— Quick scanning
— Image quality within a ±50 micron accuracy
— The system via software can perform fitness for purpose calculations
— Only for surface and volumetric type features

In-Line Inspection (ILI) Using Tethered Tools and Robotic Crawlers
Useful when standard free swimming tools are impractical due to piping constraints (e.g. multiple diameters, tight or complex bends or miters, fittings, valve restrictions, low flow or no flow conditions, no launcher or receiver facilities)
— More thorough assessment of pipe integrity,
— Uses conventional ILI technologies such as MFL, Eddy Current, Ultrasonic, Electromagnetic Acoustic Transmitter, and Geometry
— The technology selected can have limitations that are inherent to any other manual methodology (e.g. crack like features with no volume may be missed using MFL technology or external metal in close proximity will not be detected by UT technology).

Hydrostatic Testing
Used as a way to establish MOP or that the piping system is not leaking.
This method can also be used as a way to remove any features that will not be able to withstand pressures above a certain value of MOP (e.g. MOP × 1.25 or 1.39).
— Simple to use, reliable, and proven
— Can be difficult to administer at an existing facility with multiple manifold connections or lack thereof
— Does not provide detailed integrity conditions for the piping system
— Pass/fail test at a specific moment in time
— Short reassessment intervals (i.e. months) can result

Table 8—Direct Inspection Methods Applicable to Facilities (Continued)
12.6.2 Scheduling Based on Routine Maintenance

Equipment that requires routine maintenance should be included on a maintenance schedule so that it is maintained according to the equipment manufacturer’s recommendations or as dictated by the operating conditions. Items may include gaskets, seals, bearings, and lubricating oils. In addition, equipment and incorrect operation threats should be addressed through operating procedures, equipment maintenance and inspection procedures, and operator training and qualification procedures that are reviewed and updated on a regular basis.

Storage tanks are an important part of facilities and tank integrity management is covered under API 653.

12.7 Prevention and Mitigation Measures

As discussed in 11.1, data integration often reveals aspects about operations and maintenance that allow an operator to address facility integrity threats and reduce the consequences of potential releases. The incident history associated with certain assets or circumstances should be considered. One or more incidents associated with any asset or circumstance may indicate the need for enhanced preventive and mitigative measures. Some examples of prevention of each facility threat are shown in Table 9 and for mitigating consequences in Table 10.

12.7.1 Corrosion (External and Internal)

Facility piping generally cannot be inspected by ILI or subjected to periodic hydrostatic testing. Inspections of facility piping and tubing depends on periodic visual inspection and other methods of indirect or direct assessment, such as the use of ultrasonic and radiographic wall thickness measurements. For additional information, see API 570 and API 2611. Pipeline operators should perform visual and wall thickness measurements more frequently where corrosion rates are known to be higher than average. Each operator should establish periodic inspection programs for the following specific types and areas of deterioration:

- external corrosion at supports and hangers;
- external corrosion at soil-to-air interfaces;
- external corrosion under insulation;
- external corrosion from interference;
- internal corrosion in dead legs, drain lines, and relief lines;
- internal erosion and corrosion/erosion.

In all cases, periodic inspections in conjunction with wall thickness measurements are suggested as ways to monitor these situations. The frequency of inspection can be based on a corrosion rate established from the measured wall thickness loss. In the absence of established corrosion rates, other methods may be used to determine corrosion rates (e.g. a Monte Carlo simulation with distributions of pit depths and corrosion starting times). Models for calculating remaining strength of corroded pipe such as Modified B31G, RSTRENG, or API 579 can be used to predict safe operating pressures on corroded tubing and piping within facilities. Operators should be cautious about using these models alone with piping that is operated at low levels of hoop stress (i.e. less than 50 % of SMYS) because the effect of contact stresses or secondary stresses could cause the failure stress to be less than that predicted by such models. In such cases the operator should consider carrying out a more sophisticated analysis, for example, by using finite element modeling.

Areas suspected to have localized corrosion/erosion should be inspected using appropriate NDE methods that will yield wall thickness data over a wide area, such as UT, GWUT, ultrasonic scanning, radiographic profile, eddy current, or external MFL. The effect of wall thickness loss on facility integrity should be determined using industry approved
Table 9—Examples of Preventive Measures to Address Facility Integrity Threats

<table>
<thead>
<tr>
<th>Threat</th>
<th>Problems Identified through Data Gathering and Integration</th>
<th>Preventive Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td>External corrosion</td>
<td>Anomalies detected with NDE methods for wall loss at a piping support and low cathodic protection readings.</td>
<td>Increase cathodic protection. Conduct more frequent inspections.</td>
</tr>
<tr>
<td>Internal corrosion</td>
<td>Internal anomalies discovered by UT at dead legs, drain lines, relief lines, or low spots.</td>
<td>Inject inhibitor. Conduct periodic flushing. Remove dead legs. Conduct more frequent inspections. Monitoring corrosion rate with coupons or probes. Sample and analyze water collected from drains or low points.</td>
</tr>
<tr>
<td>Erosion and corrosion/erosion</td>
<td>Wall thickness measurement using UT discovered thinning at a 90 degree bend.</td>
<td>Install filters to remove particulates; minimize locations with abrupt velocity changes; increase frequency of inspections at locations more susceptible to erosion.</td>
</tr>
<tr>
<td>Environmental cracking—Ethanol related cracking</td>
<td>PAUT identified internal cracking in ethanol piping.</td>
<td>Inject inhibitors and oxygen scavengers. Apply internal coatings. Reduce residual tensile stresses.</td>
</tr>
<tr>
<td>Manufacturing defects</td>
<td>Quality control identified out of specification butt welded tee and elbow.</td>
<td>Improve procurement practices to meet specifications. Quality control during installation. Identify similar issues in other locations.</td>
</tr>
<tr>
<td>Construction and fabrication defects</td>
<td>Heavy fittings installed on small piping exposed to vibration.</td>
<td>Quality control during installation. Install additional support to minimize vibration.</td>
</tr>
<tr>
<td>Equipment failure</td>
<td>Seeps or stains in facilities at fittings, flanges, pump seals, or valve packing.</td>
<td>Increase frequency of inspections. Replace gasket materials at specific intervals or when inspections indicate gasket deterioration. Develop flange torque procedures.</td>
</tr>
<tr>
<td>Mechanical damage with immediate failure</td>
<td>Vehicular impacts to facility equipment.</td>
<td>Establish exclusion zones where large vehicles are not permitted without additional surveillance.</td>
</tr>
<tr>
<td>Incorrect operations</td>
<td>Improper installation of tubing and small piping. Flanges installed without considering torque limits. Tank overfill.</td>
<td>Establish procedures and conduct training to reduce the likelihood of improper installation of equipment.</td>
</tr>
<tr>
<td>Weather/outside force</td>
<td>Water freezing in tubing causing actuated equipment to malfunction.</td>
<td>Increase inspection frequency for equipment prone to water accumulation and exposed to cold temperatures</td>
</tr>
</tbody>
</table>

Methods such as Modified B31G, RSTRENG, or API 579, and piping that exhibits inadequate remaining strength should be repaired, reinforced, or replaced.

Operators should specifically consider the potential for interference at facilities because of the close proximity to electrical systems that may not be isolated. For equipment that might be affected by interference, operators should ground and bond equipment, use sacrificial anodes, or try to eliminate sources of interference, where possible.

### 12.7.2 Erosion and Corrosion/Erosion

Areas suspected to have localized erosion or corrosion/erosion should be inspected using appropriate NDE methods that will yield wall thickness data over a wide area, such as UT, GWUT, ultrasonic scanning, radiographic profile, eddy current, or external MFL. The effect of wall thickness loss on piping integrity should be determined using industry approved methods such as Modified B31G or RSTRENG, and piping that exhibits inadequate remaining strength should be repaired, reinforced, or replaced.
<table>
<thead>
<tr>
<th>Consequences</th>
<th>Mitigative Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ignition of vapor cloud in occupied area.</td>
<td>Educate the employees and nearby public as to the danger of a vapor cloud. Provide emergency phone number to residents. Increased frequency of inspections. Improve emergency response criteria.</td>
</tr>
<tr>
<td>A release results in large drain-down.</td>
<td>Install EFRDs and containment berms or dikes. Increase frequency of inspection. Improve emergency response criteria.</td>
</tr>
<tr>
<td>Small leak over time accumulates into large release.</td>
<td>Improve leak detection systems. Increase frequency of inspections.</td>
</tr>
<tr>
<td>Fire that causes the loss of a facility</td>
<td>Upgrade fire detection and prevention measures. Improve remote monitoring of the facility. Enhance emergency response criteria.</td>
</tr>
</tbody>
</table>

### 12.7.3 Environmentally Assisted Cracking

Where specific segments or piping circuits have a demonstrated susceptibility to environmental cracking, the operator should schedule supplemental inspections. Such inspections can take the form of NDE, PT or magnetic-particle testing (MT). Where feasible, suspect spools may be removed from the piping system and split open for internal surface examination. API Bulletin 939E provides guidelines for identification, mitigation and prevention of ethanol SCC.

### 12.7.4 Manufacturing Defects

Manufacturing defects at facilities can include equipment body defects, components not meeting engineering specifications, and seam weld defects. Quality control during procurement can prevent manufacturing defects from entering service. Inspection protocols and procedures can identify equipment and piping manufacturing defects in service.

### 12.7.5 Construction and Fabrication Defects

Construction defects at facilities can include fabrication weld defects, dents, or gouges that occur during construction activities, and improper installation of equipment, piping, flanges, and fittings. These threats can be prevented or mitigated through the use of approved procedures, inspection protocols, and robust quality assurance and control programs during construction activities.

### 12.7.6 Equipment Failure

Pipeline operators should take steps to minimize the risk of tubing and small-bore piping failures by replacing instrumentation lines with electrical signal devices where possible. For example, pressure readings can be conveyed electrically from pressure transducers rather than through tubing connecting the pressurized fluid to a mechanical pressure gage. Operators should also maintain adequate and up-to-date P&IDs. Configuration of the tubing should be designed to eliminate long runs, reduce or prevent vibration, and allow for periodic inspection. Visual inspections of the tubing and piping should be carried out at regular intervals to ensure that they are properly installed and inspected per manufacturer’s recommendations.

A pipeline operators facility IMP should address the periodic inspection and routine maintenance of such equipment with the intent of preventing equipment failures. Attention should be paid to known mean times to failure for commonly used components, and a timely replacement of parts or units.
12.7.7 Mechanical Damage

Facility locations susceptible to damage from vehicular impact should be protected by fencing, concrete bollards, or other physical barriers. First, second, and third party impacts on above-ground and below-ground facility piping and equipment are also possible. Similar methods as discussed in 11.2.1 can also be applied to pipeline facilities such as surveillance, observers during construction activities, and guidelines for contractors.

12.7.8 Incorrect Operations

Incorrect operations can involve process upsets due to slug flow, cavitation, changes in fluid dynamics, upstream or downstream process changes, overpressures, and tank overfills. When appropriate, an operator should use root cause analysis to uncover underlying drivers that can lead to operator error incidents. Operators can reduce or eliminate situations that provide an opportunity for human error throughout the lifecycle of a facility. Operators can maximize learning opportunities by communicating lessons learned from incident investigations and periodic reviews of operations and maintenance practices and procedures. For unusual operations and one-time events, operators should consider developing detailed work plans and conducting a job safety analysis (JSA) or process hazard analysis (PHA) to reduce the risk of error during unfamiliar situations. Operator qualification (OQ) programs help to reduce human error through training on specific tasks under normal and abnormal conditions.

12.7.9 Weather and Outside Force Related Defects

Equipment at facilities can be susceptible to damage from weather events such as tornadoes, hurricanes, floods, lightning, and extreme temperatures and as such, operators should implement spill prevention and control measures to reduce potential consequences of a release from weather events. In addition, where inspections or patrols indicate ground movement could increase the stress on piping and equipment, operators should consider increasing monitoring or performing additional inspections.

12.7.10 Mitigation of Consequences at Facilities

Multiple methods are used to mitigate consequences at facilities. Storage tanks are constructed inside berms or dikes to prevent releases from impacting surrounding areas. Emergency flow restriction devices (EFRDs) and leak detection are used to minimize the amount of product that can be released during an unintended release. Sumps and drains contain and direct spills to safe locations. Mitigation can also include the use of higher toughness materials for pipe and vessels, improved methods for recovery and clean-up, and limiting the presence of personnel in hazardous areas.

13 Program Evaluation

13.1 General

Operators should periodically measure and evaluate the effectiveness of their IMP. The review should include both measures of integrity performance, as well as measures of the program itself. The intent of this section is to provide operators with a methodology that can be used to evaluate the effectiveness of their pipeline and facility integrity management. An integrity management program evaluation should help an operator answer the following questions:

a) Were all integrity management program objectives accomplished?

b) Were pipeline and facility integrity and safety effectively improved through the integrity management program?

The operator should collect performance information and periodically evaluate the effectiveness of its integrity assessment methods and its preventive and mitigative risk control activities including repair. The operator should also evaluate the effectiveness of its management systems and processes in supporting integrity management decisions. A combination of performance metrics and system self-reviews is necessary to evaluate the overall effectiveness of an integrity management program. Operators may consider communicating the benefits and accomplishments of
their IMPs and activities to various stakeholders including regulators and the public. For further guidance, refer to the PHMSA document, *Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics*.

13.2 Performance Measures

There are multiple categories of measures necessary to demonstrate the effectiveness of an IMP. The integrity of the pipeline or facility, operations and maintenance activities performed, as well as program management activities all contribute to the safety performance of a pipeline or facility. Each of these types of measures can be made through comparisons between leading (proactive or goal-oriented) activities or benchmarks and lagging (reactive or outcomes-oriented) indicators. Operators are encouraged to select as many measures as needed for their system. Evidently, the period of measuring may vary because it may take years rather than weeks or months to achieve a meaningful measurement of the effectiveness of some integrity assessments, mitigation, and preventive measures.

13.2.1 Integrity Performance Measures

Pipeline and facility integrity performance measures examine the state of the asset itself. Integrity measures can include issues surrounding pipe corrosion, cracking or dents in the pipeline. While not the most frequent cause of pipeline incidents, these integrity issues can result in larger releases per incident and the largest portion of total barrels released. Examples of integrity performance measurements from the standpoint of threats to pipeline and facility integrity are presented in Table 11.

The performance measures are presented by an integrity threat in Table 11. All threats applicable to an operator’s system should be included. For the hypothetical example represented in Table 11, the operator was concerned with six of the 10 threats listed in Section 5 and Annex A. For simplicity, only one or two performance measures are included in this example, but an operator may identify many performance measures for each threat.

As shown in Table 11, a similar review and evaluation matrix exists for the other five threats. The actual matrix of performance measurements used by any given operator may or may not look similar to Table 11. It will probably contain many more performance measurements and goals than observed, because many aspects of integrity management should be assessed.

13.2.2 Operation and Maintenance Performance Measures

Operations and maintenance measures can track issues associated with operator error and equipment failure. Even though operations and maintenance issues generally result in smaller releases per incident, they are a leading cause of pipeline incidents and should be measured as a category of safety performance. Specific examples of incorrect operation might include storage tank overfills or valves left in the wrong position. Equipment failure measures may track pump failures, defective relief valves or loose fittings. Operators should also consider measuring excavation damage by operator personnel or contractors. These described measures of incident causes are lagging indicators. Thus, operators should also consider leading indicators of operations and maintenance effectiveness, such as providing training on new leak-detection software or conducting fire alarm drills for control room operators.

13.2.3 Program Management Performance Measures

In addition to measures of integrity and measures reflecting operation and maintenance of the pipeline and facilities, operators should also measure the management of their integrity program. As discussed in Section 4, elements of an IMP accomplish the threat management goals of the program through both direct integrity-related activities, as well as supporting activities to improve the quality of the program itself. IMP elements from Section 4 are repeated in Table 12 with potential measures of their effectiveness.
Table 11—Examples of Integrity Performance Measurement by Threat

<table>
<thead>
<tr>
<th>Threat</th>
<th>Measure Numbering</th>
<th>Process Measures</th>
<th>Operational Measures</th>
<th>Integrity Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Leading</td>
<td>Lagging</td>
<td>Leading</td>
</tr>
<tr>
<td>External corrosion</td>
<td>1</td>
<td>Planned to inspect 20 highest risk segments in Year 1</td>
<td>Actually inspected 19 highest risk segments</td>
<td>Installed 10 new rectifiers in Year 1. Repaired or replaced out-of-service rectifiers for all impressed current CP systems. Installed temporary CP equipment when/where necessary.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Leading</td>
<td>Lagging</td>
<td>CP Potentials on all segments brought into compliance with required criteria.</td>
</tr>
<tr>
<td>Internal corrosion</td>
<td>1</td>
<td>Planned to inspect one problematic segment</td>
<td>Inspected segment and repaired all anomalies over 50 % of wall</td>
<td>Reliably injected approved corrosion inhibitor at proper rates. Ran cleaning pigs with an appropriate frequency.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Leading</td>
<td>Lagging</td>
<td>ILI or spot checks of hold up locations after five years showed no more wall loss. Sampled transported fluids, examined debris from running of cleaning pigs, reviewed internal corrosion monitoring equipment results (metal loss coupons, fluid resistivity probes, UT wall thickness measurements, etc.).</td>
</tr>
<tr>
<td>Stress corrosion cracking (SCC)</td>
<td>1</td>
<td>Planned to hydrostatically test two segments every 10 years</td>
<td>Hydrostatically tested two segments in Year 1</td>
<td>Recoated 20 miles of pipe where old coating was mostly disbonded</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Leading</td>
<td>Lagging</td>
<td>Spot checks after 10 years showed no areas of disbonding</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lagging</td>
<td>Leading</td>
<td></td>
</tr>
</tbody>
</table>
Table 11—Examples of Integrity Performance Measurement by Threat (Continued)

<table>
<thead>
<tr>
<th>Threat</th>
<th>Measure Numbering</th>
<th>Process Measures</th>
<th>Operational Measures</th>
<th>Integrity Measures</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Leading</td>
<td>Leading</td>
<td>Leading</td>
</tr>
<tr>
<td>Mechanical damage (immediate failure)</td>
<td>1</td>
<td>Contact every land occupant once in three years</td>
<td>Personal contact was made with 95% of land occupants</td>
<td>Land occupants informed of risks and obligations More than</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>Hire additional personnel for ground patrolling</td>
<td>Four technicians added to ground patrol staff</td>
<td>Enhanced ground patrols to once a week in critical areas</td>
</tr>
<tr>
<td>Fatigue crack growth of seam defects</td>
<td>1</td>
<td>Conduct hydrostatic retest of 10 segments once every 10 years</td>
<td>Hydrostatic retests of five segments completed within first two years</td>
<td>Install variable speed pumps at stations in fatigue affected segments at outset of program</td>
</tr>
<tr>
<td>Program ID</td>
<td>Program Element</td>
<td>Potential Measures</td>
<td></td>
<td></td>
</tr>
<tr>
<td>------------</td>
<td>-------------------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>Identification of Threats to Pipeline Integrity</td>
<td>Are threats identified for particular pipeline segments accurate? Are they comprehensive? Are they up-to-date?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Identification of Potential Impacts to Critical Locations</td>
<td>Are populated and environmentally sensitive locations accurately identified? Does information reflect recently changed or expanded critical locations?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Risk Assessment and Segment</td>
<td>Did risk assessments appropriately reflect threat and consequence data? Were the prioritized segments ranked appropriately based on the integrity assessment findings?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Assessment Plan Development or Revision</td>
<td>Did planned inspection techniques or technologies accurately reflect assessed risks? Did assessment schedule appropriately reflect assessed risks?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Pipeline Inspections, Testing and Examinations</td>
<td>Did the type and timing of inspection, testing and examination reflect the assessment plan?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Pipeline Integrity Data Collection</td>
<td>Was pipeline integrity data from inspections, testing and examination collected thoroughly and in a timely manner? Was integrity excavations and maintenance information collected?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Program Performance Data</td>
<td>Were program performance metrics developed and data collected on program elements?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Management of Change Review</td>
<td>Were changes to system design, operation, or maintenance identified and evaluated? Were changes incorporated into risk assessments?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Integration of Tool and Program Performance Data with MOC Measures</td>
<td>Were sources of information identified and procedures established to ensure collection from those sources? Was data collected from those sources? Was data integrated and analyzed for its cumulative impact?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Review of Operator, Industry, and Regulator Learnings and Recommendations</td>
<td>Were operator, industry and regulator learnings and recommendations identified? Incorporated into risk assessment or integrity plans?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Evaluate Integrity Program Performance</td>
<td>Were results of program measures evaluated? Was effectiveness of integrity program evaluated?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Assess Pipeline Integrity</td>
<td>Were results of integrity measures and operations and maintenance measures evaluated? Were results of integrated data analysis evaluated? Were pipeline integrity results integrated into risk assessment and plan development?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Pipeline Remediation Activities</td>
<td>Did remediation activities reflect pipeline integrity results? Did remediation activities reflect identified threats and assessed risks?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Preventive and Mitigative Activities</td>
<td>Did damage prevention, corrosion, emergency response or other activities effectively prevent and mitigate threats?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>15</td>
<td>Reassessment Interval Calculations</td>
<td>Are the reassessment intervals appropriate?</td>
<td></td>
<td></td>
</tr>
<tr>
<td>16</td>
<td>Integrity Program Improvement Actions</td>
<td>Were program improvement actions taken in response findings of integrity program evaluation?</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
13.2.4 Meaningful Measures and Incidents Impacting the Public or Environment

While it is important to measure a broad range of integrity activities and performance results, some measures are considered more meaningful because they reflect incidents with an impact to the public or environment. An example is the meaningful measures developed in the United States jointly by regulators, liquid pipeline operators and pipeline safety advocates. These measures, defined below, track liquid pipeline incidents impacting people or the environment (IPE).

a) Regardless of incident location, incidents resulting in:
   - death;
   - serious personal injury;
   - fire;
   - explosion;
   - wildlife impacts;
   - ocean water, drinking water or ground water contamination;
   - soil contamination;
   - public or non-operator private property damage.

b) For incidents not totally contained on operator controlled property:
   - unintentional release volume greater than or equal to 5 gallons in an HCA;
   - unintentional release volume greater than or equal to 5 barrels outside an HCA;
   - surface water contamination;
   - soil contamination.

In addition to total IPE incidents, also measured are IPE incidents with causes expected to be found by integrity inspection and IPE incidents with causes dependent on operations and maintenance. Operators should consider including in their internal performance measures these or similar types of meaningful measures based on public, environmental or sensitive location, and volume factors.

13.3 Performance Tracking and Trending

Evaluating performance relative to actions taken, calculations made, and goals set for improvement as Table 9 are, in a sense, relative measures. A pipeline operator should also evaluate IMP in more holistic terms by considering questions such as:

- Will the goals, if achieved, enhance pipeline and facility safety and integrity significantly? (i.e. will the benefits outweigh the costs)
- Are the results on par with those of other operators?
- Will regulatory expectations, if applicable, be met?
To meet these conditions, the operator should conduct periodic evaluations of their own performance in comparison with industry-wide data sources. For example, a U.S. operator can review its performance in comparison with the database of reportable incidents maintained by the U.S. Department of Transportation. Other countries maintain similar incident databases as well. U.S. operators may also take advantage of two voluntary performance tracking programs. Both were mentioned previously in Section 11 and Section 12. One is the DIRT database of excavation hits and near misses maintained by the Common Ground Alliance. The other is a general incident reporting database maintained by API that is referred to as the PPTS. By participating in and examining such databases, a pipeline operator can compare its integrity management effectiveness against the levels of effectiveness with other operators' programs. The pipeline operator should then make improvements in its program if the need is indicated by the comparisons.

13.4 Self-Reviews

Self-reviews of integrity management programs should be performed to establish and maintain the quality and effectiveness of the programs. These reviews should be performed periodically by the operator's own personnel, and external reviews by an independent outside organization should occur when deemed necessary (e.g. self-reviews found significant deficiencies in the IMP, the occurrence of a significant incident identified a weakness in the plan). In some jurisdictions, inspections by regulatory authorities will be mandated. Reviews should address the following questions:

— Are activities being performed as outlined in the operator’s program documentation?
— Is someone assigned responsibility for each subject area?
— Are appropriate resources available to those who need them?
— Are the people who do the work trained in the subject area?
— Are qualified or certified people used where required by code or regulation?
— Are activities being performed using an appropriate integrity management program as outlined in this document?
— Are all required activities documented by the operator?
— Are action items followed-up?
— Is there a formal review of the rationale used for developing the risk criteria used by the operator?
— Are the criteria for assessing and remediating anomalies adequate?
— Are the criteria for establishing reassessment frequencies adequate?
— Are the criteria for preventive and mitigative measures adequate?
— Are the criteria for the assessment of non-pipeline facilities adequate?
— Are there processes for internal and outside auditing?
— Is there a process for review and updating of the program in response to changes in the pipeline attributes, changes in operating conditions, changes in technology, and changes in code or regulatory requirements?
— Are incidents being reduced?
— Are procedures being updated based on new knowledge (major events, new regulations, new advisories, new research)?
— Is knowledge being shared throughout the organization?
— Is knowledge being shared throughout the pipeline industry?

13.5 Performance Improvement

The results of the performance evaluation should be used to modify the IMP as part of a continuous improvement process. Recommendations for changes and improvements should be based on analysis of the performance measures and the audits. All recommendations for changes and improvements should be documented, and the recommendations should be implemented in the next cycle of integrity assessment.

14 Management of Change

14.1 General

The operator should develop formal management of change procedures to identify and consider the impact of changes in pipeline attributes, pipeline operations, technology, and code or regulatory requirements on an operator’s IMP. See API RP 1173, First Edition, Section 8.3 regarding management of change.

Management of change should address operational, technical, physical, procedural, and organizational changes to the operator’s pipeline system. A management-of-change process should include the following:

— description of the change;
— reason for the change;
— effective date for change to occur;
— authority approving the change;
— analysis of implications of the change;
— acquisition of required work permits for any necessary construction or operational changes;
— list of roles, responsibilities, and accountabilities for management-of-change stakeholders;
— modification of appropriate elements of the IMP;
— documentation of change and rationale;
— communication of change to affected parties;
— implementation of the change;
— workflow process for assuring that management-of-change stakeholder concerns are addressed.

Examples of how an operator might organize a management-of-change plan are provided in Table 13.
<table>
<thead>
<tr>
<th>Description</th>
<th>Reason</th>
<th>Effective Date</th>
<th>Implications</th>
<th>Authority</th>
<th>Work Permits</th>
<th>Modifications to IMP</th>
<th>Documentation</th>
<th>Communication</th>
<th>Implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Raising MOP</td>
<td>To increase capacity</td>
<td>Two years from current date</td>
<td>New pumping units to be in-stalled at Stations 1 and 2. Need to retest to 1.25 times new MOP.</td>
<td>Authorized by Board of Directors and approved by FERC</td>
<td>Construction permits to install new pumps and associated control equipment. Work and environmental permits for retest.</td>
<td>Reevaluate remaining life of unrepai red anomalies. Calculate effect of retest to see if it holds the margin of safety until the next ILI. Manager of pipeline integrity will change, not expected to impact IMP.</td>
<td>Managers of pipeline and facility integrity will prepare full reports of all construction and retesting and modify the IMP as required</td>
<td>Managers of pipeline and facility integrity will prepare memos to staff and operating personnel and inform PHMSA and state regulators</td>
<td>Upon completing of construction and retesting the MOP will be raised to the new level</td>
</tr>
<tr>
<td>Appointment of new company president</td>
<td>Retirement of current president</td>
<td>Six months from current date</td>
<td>Organizational changes will follow</td>
<td>Authorized by Board of Directors</td>
<td>None</td>
<td>Change text where necessary to indicate use of new tool is mandated</td>
<td>New organization chart will follow</td>
<td>New organization chart will serve as documentation</td>
<td>Schedule for IMP will be unaffected</td>
</tr>
<tr>
<td>New crack tool to be used to assess Line 1</td>
<td>Improved sensitivity</td>
<td>Next scheduled ILI</td>
<td>Staff responsible for ILI will attend orientation on new tool</td>
<td>Authorized by Manager of Pipeline Integrity</td>
<td>None</td>
<td>IMP public awareness section will be modified to indicate the land occupant contact program</td>
<td>Person responsible for ILI section of IMP will make the necessary changes to the text</td>
<td>Manager of Pipeline Integrity to send memo to all staff involved in IMP implementation.</td>
<td>New tool to be used for next assessment of Line 1</td>
</tr>
<tr>
<td>Begin program of personal contacts with land occupants.</td>
<td>Need to reduce encroachment s with no one-call</td>
<td>Beginning three months from current date</td>
<td>Selected staff will be trained to interact with land occupants, informing them of the risks and trying to secure their cooperation</td>
<td>Authorized by Manager of Pipeline Integrity</td>
<td>None</td>
<td>Manager of pipeline integrity will see that the appropriate sections of IMP are changed and document training of the relevant staff</td>
<td>Manager of Pipeline Integrity to send memo to all staff involved in IMP implementation</td>
<td>Contacts will begin in three months and a full cycle of contacts is expected to be completed in two years. Cycle will be repeated every two years</td>
<td></td>
</tr>
</tbody>
</table>
14.2 Management of Change—Newly Constructed Systems or New Acquisitions

For newly constructed systems considerations should be taken for a risk-based design approach that makes design and route adjustments based upon area hazards and risk factors. These considerations should identify the pipeline’s impact to critical locations. In addition, a quality management system should be in place for quality assurance of construction, materials procurement, and services provided. Refer to API 1177, Construction Quality Management Systems, API Specification Q1, Specifications for Quality Management Systems for Manufacturers for Petroleum and Natural Gas Industries, and API Specification Q2, Specifications for Quality Management Systems for Service Providers for Petroleum and Natural Gas Industries for additional guidance.

Onboarding systems via acquisition or change of operatorship should identify all relevant information and data to ensure adequate transition of the IMP from the previous operator to the new operator.

14.3 Management-of-Change Operations

Operational changes, such as flow reversals, product changes, conversion of service, and increase in throughput, should be evaluated for their impact on integrity. These operational changes can impact various aspects of a pipeline’s operation, maintenance, monitoring, integrity management, and emergency response, including the following:

— Pressure gradient, velocity, and the location, magnitude, and frequency of pressure surges and cycles may change.

— Throughput increases may impact the pressure profile and pressure transients.

— Product changes may warrant a material compatibility and corrosion susceptibility review.

— Leak detection and monitoring systems may be affected.

— Significant additions, removal or modifications of pump stations, tank farms, and ILI launching/receiving facilities may be required.

— Appurtenances such as flow meters, strainers, corrosion control devices, leak detection devices, control valves and sectionalizing valves may need to be altered.

Refer to the PHMSA Document, Guidance to Operators Regarding Flow Reversals, Product Changes and Conversion to Service for additional guidance.

14.4 Management-of-Change Pipeline Status

Changes in the operational status of a pipeline, i.e. active, idle, decommissioned, abandoned, or combinations thereof, should consider implications of such a change on integrity management of the pipeline.

Regulatory requirements for the type and frequency of integrity assessments may differ based on a pipeline’s operational status, especially for pipelines that have been appropriately purged and isolated. Operators should be aware of these differences and make appropriate changes to integrity management programs to account for a pipeline’s operational status.

NOTE  PHMSA Advisory Bulletin ADB-2016-05 and the PHMSA NPMS Operator Standards Manual provide clarification of terms and expectations of the operational status of pipelines in the United States.
Annex A
(normative)

Threats to Pipeline Integrity

A.1 Introduction

Ten common integrity threats to hazardous liquid pipelines that operators should address are identified in 5.1. Not all 10 threats may apply to every hazardous liquid pipeline and therefore pipeline operators may want to customize their integrity management approach when considering these threats. Annex A presents definitions and descriptions that are intended to assist a pipeline operator with the identification of these threats to pipeline integrity.

A.2 External Corrosion

Corrosion is defined as the deterioration of a material, usually a metal, that results from a reaction with its environment. The rate in which a metal will deteriorate (corrode) is primarily governed by the environment in which it resides and by the nature and aggressiveness of measures that have been put in place to mitigate the reaction. Although there are several different forms of corrosion, each share some common elements:

— an anode;
— a cathode;
— a metallic path connecting the anode and cathode (typically the pipe itself);
— an electrolytic path connecting the anode and cathode (typically the soil and groundwater when external corrosion is being considered).

Eliminating any of the four elements will stop the electrochemical reaction. The elimination of one of the four common elements is the basis for a corrosion control program. The most common methods of external corrosion control are selecting a material with inherent resistance to corrosion in a particular environment, applying protective paints and coatings to exposed external surfaces, applying cathodic protection, and preventing external stray currents.

When a pipeline is placed in the ground, the pipeline itself is the metallic path and the soil is the electrolyte. Areas of the pipe surface that come into contact with the electrolyte because of faults in any protective coating will tend to be either anodic to the environment (meaning ions will flow from the metal surface to the environment and metal will be consumed) or cathodic to the environment (meaning ions will flow from the environment to the metal surface and the metal will be protected). External corrosion may be controlled by the combined use of protective coatings and cathodic protection. Protective coatings form a barrier between the pipe steel and the soil, thus isolating the pipe from the electrolyte.

A.2.1 Galvanic (Electrolytic) Corrosion

One form of external corrosion, galvanic or electrolytic corrosion, may occur simply because the amount and distribution of cathodic protection current is inadequate. A pipeline operator should periodically monitor the pipe-to-soil potential levels along the pipeline. This should be done at least once a year using permanent test leads installed at intervals (usually every mile or so) along the pipeline. Occasionally, a pipeline operator should consider doing a “close-interval” pipe-to-soil potential survey. Such a survey involves acquiring potential measurements every few feet along the pipeline. The close-interval survey is much more likely to disclose local areas of inadequate cathodic protection than the test lead monitoring. Suggested levels of pipe-to-soil potential required for adequate protection are given in NACE International SP0169. Galvanic corrosion can also occur when dissimilar metals are embedded in an electrolyte such as moist soil. Thus, corrosion may occur preferentially at a weld in a piece of buried pipe because the microstructure and chemical content of the weld metal may differ significantly from those of the base metal.
Corrosion may occur even when pipe-to-soil potential measurements suggest adequate protection. Examples are cases where disbonded coating, rocky areas, or road-crossing casings shield the pipe from the protective current. Pipeline operators should be aware that such areas could exist along a pipeline and consider possibly enhanced inspections or mitigative measures.

Some external coating systems used to protect pipelines can lead to accelerated corrosion rates, including:

- thermally insulating coating materials,
- shrink wrap coatings typically applied at girth welds during construction and repair,
- polyethylene tape wrapped coatings.

For each of these coating systems, reduction in the effectiveness of cathodic protection systems and the potential for water to collect next to the external surface of the pipe underneath the coating can result in higher corrosion rates. For thermally insulated pipe, corrosion under insulation (CUI) can occur with the formation of oxygen starved corrosion products such as magnetite and goethite which are magnetic to different extents and can affect ILI accuracy. NACE International publication 10A392 provides reasons why CP has limited effectiveness on buried insulated underground structures. Shrink wrap coatings on girth welds can be effective when applied properly. Inadequate surface preparation and contamination during the application of shrink wrap coatings can cause the coating to disbond, trap moisture and shield protective currents. For polyethylene wrapped coating, raised seam welds, improper wrap tension, and overlap areas can result in a tented area for water to collect; the polyethylene tape can also shield the cathodic currents.

A.2.2 Stray Current Corrosion

Stray current corrosion is corrosion (usually pitting) caused by the influence of outside sources of electrical currents that cause electrons to flow off of exposed pipe surfaces. Stray current corrosion can be caused by either direct current (DC) or alternating current (AC). Pipeline operators should be aware that DC corrosion can be caused by interference from foreign cathodic protection systems, from mining operations, from electric railways, or from ground return or unbalanced phases of DC power transmission systems. AC corrosion can arise when a pipeline runs parallel to a high-voltage AC transmission system and AC voltage is induced onto the pipeline. In many of these cases, AC corrosion may be most severe where the pipeline right-of-way becomes parallel to, or diverges from, the adjacent AC transmission right-of-way. AC corrosion on nearby pipelines can also be caused by AC fault currents flowing through the ground.

A.2.3 Microbiologically Influenced Corrosion (MIC)

Another corrosion threat to pipeline integrity arises from MIC. Acidic compounds produced by certain types of bacteria may attack an external or internal pipeline surface. The bacteria are often capable of forming an external film that shields the pipe from cathodic protection. Pipeline operators should be aware of this phenomenon and take appropriate steps to mitigate its effects.

A.2.4 Other Forms of External Corrosion

The real extent of external corrosion usually depends on how large an area of external coating is damaged or missing and on the ability of cathodic protection current to reach the surface of the pipe underneath the area of coating disbondment. Typically, the metal loss that results is not uniform but instead appears as isolated pits or arrays of pits of various sizes and shapes. The effect of the metal loss on the pressure carrying capacity depends on the amount of material remaining along the axis of the pipe. When the pitting is randomly oriented, the integrity of the pipe becomes seriously impaired if and only if one or more pits becomes deep enough to penetrate the wall thickness (resulting in a leak) or a sufficient number of pits overlap along a sufficient length of the pipe to cause the remaining ligament to fail (often resulting in a rupture). Corrosion can also occur in the longitudinal seam without displaying a concentrated
attack in the weld bondline, fusion zone, or HAZ. Less typically, the metal loss may occur in a concentrated manner predominantly in the longitudinal direction of the pipe. One such case is SSWC that is discussed separately in Section A.3. Another is narrow axial external corrosion (NAEC) often found at double submerged arc welded seams coated with polyethylene tape. The “tenting” of the tape over the crown of the weld allows the intrusion of water and provides an environment that could shield the external surface of the pipe from cathodic protection. This shielded area is axially oriented and limited to the area immediately adjacent to the seam weld. The resultant groove-like defect is more likely to rupture than typical pitting corrosion.

A.3 Internal Corrosion

As discussed in Section A.1, an anode, a cathode, a metallic path connecting the anode and cathode, and an electrolytic path connecting the anode and cathode must be present for corrosion to occur. Eliminating any of the four will stop the electrochemical reaction and can be used as the basis for a corrosion control program. The most common methods of internal corrosion control are selecting a material with inherent resistance to corrosion in a particular environment, applying internal coatings or linings to exposed surfaces, removing electrolytes from product streams, injecting corrosion inhibiting chemicals, and preventing internal stray currents.

Internal corrosion has, mechanically speaking, the same deleterious effect on the pipe as external corrosion, but its causes are different. Refined petroleum products and crude oil can contain water, bacteria, chemical contaminants, and debris that can create a corrosive environment on the internal surface of the pipe. Water based pipeline products, being transported for commercial use or disposal, can often be considered to be environmental hazards if unintentionally released. Localized corrosion, uniform corrosion, environmentally assisted cracking (EAC), and flow-assisted damage are the typical forms of internal corrosion attack. While cathodic protection applied internally can be effective in mitigating internal corrosion (such as inside a water tank), it is typically not used internally in pipelines due to difficulties in application, disruption of product flow, presence of valves, inaccessibility, etc. Corrosion treatment chemicals such as inhibitors or biocides, or both, are often used to combat internal corrosion. Using cleaning pigs at regular intervals, and often in conjunction with chemical treatment, is an effective technique for removing accumulated water and debris from a product pipeline and helps prevent internal corrosion. It is also helpful to maintain sufficient product flow rates to avoid pooling of water in low spots along the pipeline route or at the beginning of steep inclines.

A.3.1 Low or Intermittent Flow

Pipeline operators should be aware of, and take available measures to minimize, low flow conditions that allow water to stagnate. Dead leg piping, for example, is a place where water and/or sludge could accumulate and cause corrosive conditions. If dead-leg piping is necessary, it should be checked regularly to see that internal corrosion and wall thickness loss is not occurring. MIC can occur internally if water containing certain kinds of bacteria is introduced into a pipeline. In such cases, treatment of the fluid with a biocide may be necessary.

A.3.2 Corrosive Products

Internal corrosion and hydrogen blisters, that form at laminations in the pipe material, can threaten pipeline integrity if the product being shipped is “sour”. If water is present as well as hydrogen sulfide and/or carbon dioxide, an acid reaction can occur that causes internal pitting of the pipe. Moreover, atomic hydrogen generated by the acid reaction can easily diffuse into the pipe steel. If the atomic hydrogen passes clear through the wall thickness, it dissipates harmlessly, but if it encounters a lamination in the pipe wall, hydrogen gas (H2) can form. The hydrogen gas can continue to form as long as atomic hydrogen is being generated at the ID surface of the pipe. The pressure of the hydrogen gas will tend to separate the lamination forming a blister. Along the longitudinal edges of a blister, cracks may form and propagate to the ID surface of the pipe. Since most laminations are located mid-wall, once the crack penetrates to the ID surface, the outer half of the wall thickness becomes the effective thickness. At that point a failure of the pipeline may occur. Operators of sour service pipelines should be aware of this potential threat and take mitigative action. Inhibitors can be used to prevent the acid reaction from occurring. Ultrasonic metal loss ILI tools can find laminations and blisters so that they can be repaired prior to an integrity failure.
A.4 Selective Seam Weld Corrosion (SSWC)

SSWC, also called preferential seam corrosion, is corrosion-caused metal loss, either internal or external, of or along an ERW or FW seam. The corrosion process attacks the seam bondline region at a higher rate than the surrounding body of the pipe, resulting in a corrosion crevice or groove aligned with the bondline. In some ERW and FW materials, this bond line region exhibits low fracture toughness. This definition is not meant to cover preferential corrosion along a sub-arc long seam.

SSWC can evade detection by conventional magnetic or ultrasonic metal loss ILI tools, but can usually be detected using CMFL, SMFL, or USCD tools. Accurate measurements in the ditch of the depth of the SSWC groove can be difficult due to the narrow groove geometry and poor reference surface condition. The combination of SSWC and low toughness in the seam bondline (if that condition is present) may create a serious defect that is more likely to cause a rupture than coincident corrosion in the body of the pipe or cause a rupture at low hoop stress. Conventional corrosion evaluation methods such as ASME B31G cannot be reliably used to evaluate SSWC if the flaw cannot be accurately sized or if the seam exhibits low-toughness behavior.

Both LF-ERW and HF-ERW can be affected by SSWC. Susceptibility may be enhanced by high sulfur content in the steel and may be reduced by calcium treatment for sulfide shape control. The presence of other elements (Cu, Ce) and thermal history may also influence susceptibility. The occurrence of SSWC may be more critical in some LF-ERW or FW pipe because of the potential for relatively low toughness of the bond line region. Electric welds were required by API 5L and 5LX to be post-weld heat treated after 1967, reducing susceptibility to low toughness due to hard microstructures in the seam bondline. Steel used to make pipe in the mid-1980s and later generally exhibit reduced sulfur content. A linear polarization resistance (LPR) test can be useful for indicating susceptibility even where no SSWC has previously been observed. Discovery of SSWC confirms susceptibility irrespective of the outcome of an LPR test.

A.4.1 SSWC Characterization

To characterize the relative corrosion rate of SSWC compared to the corrosion rate and associated overall metal loss by the base metal, Equation (A.1) shows the grooving factor is sometimes used as:

$$\alpha = \frac{d_1}{d_2} = 1 + \frac{a}{d_2}$$  \hspace{1cm} (A.1)

where the grooving factor, $d_1$ is the distance from the original metal surface prior to the onset of corrosion to the depth of the weld groove, and $d_2$ quantifies the overall metal loss of the material. Thus, a grooving factor of 1.0 would indicate that SSWC had not occurred and that all metal loss was general and uniform across the surface. Grooving factor values greater than 2 (e.g. the seam weld is corroding at a rate that is twice that of the rest of the surface) are typically considered to indicate susceptibility and threat of SSWC, though the rationale for selecting this value is unclear.

A.5 Environmentally Assisted Cracking (EAC)

A.5.1 Stress Corrosion Cracking (SCC)

SCC is a form of EAC, where small cracks form and often continue to lengthen and deepen over a period of time. Typically, multiple small individual cracks form adjacent to one another in an array. If the cracks continue to grow, they frequently overlap or coalesce or both such that they become the equivalent of a large single crack in terms of their effect on the pressure carrying capacity of the pipe. If crack growth continues, a crack can eventually become large enough to cause the pipeline to leak or rupture. Three conditions must be present for SCC to occur:

1) a susceptible material;
2) a conducive environment;
3) a tensile stress.

Material—All commonly used line pipe steels are susceptible, though susceptibility may vary considerably from one material to another.

Environment—Specific forms of SCC are associated with specific terrain and soil types, particularly those having alternated wet-dry conditions and those that tend to damage or disbond coatings. SCC can occur in almost any soil type since the local electrochemistry at the pipe surface may be isolated from the surrounding conditions. Thus pipe coating type and condition can be an important factor.

Stress Level—Susceptibility to SCC increases with stress level, and pipelines that are operated at stress levels above 60% of SMYS appear to be most susceptible, although SCC has been identified in pipelines operated at lower stress levels typically associated with localized phenomena such as dents or gouges. SCC has been identified at points of stress concentration such as weld toes and mechanical damage. Residual stresses from pipe forming or welding can also contribute to susceptibility. Circumferentially oriented SCC has occurred where longitudinal stresses due to soil movement exceed a stress threshold, even in pipelines operating at low levels of hoop stress. Refer to API RP 1176 for further discussion of the relative importance of causal factors and their relationships.

Two forms of SCC have been identified as high-pH and near-neutral pH SCC. The high-pH form tends to occur within a narrow cathodic potential range and at a local pH over 9. It is associated with increased pipe operating temperatures. Cracks tend to be narrow and primarily intergranular. Pipe with coal tar and asphalt coatings are sometimes susceptible to this type of cracking. Near-neutral pH SCC tends to occur at a local pH of 5.5 to 7.5. It is associated with mild concentrations of CO2 in groundwater. Cracks are usually trans-granular, wide, and more corroded than those found in high pH SCC. Generally, tape coated systems are susceptible to this type of environment. At the time this document was prepared, no one appears to have ever encountered SCC on a pipeline with a properly applied fusion-bonded epoxy coating. The absence of SCC in conjunction with such a coating is thought to be attributable to the facts that the pipe surface has to be shot-blasted before its application and that the compressive residual stress induced at the pipe surface by the shot-blasting raises the threshold stress for SCC above the level that the pipe will experience in service.

A.5.1.1 SCC Susceptibility

Pipeline operators should determine whether a segment of pipe may be susceptible to SCC particularly if the pipeline is known to be subjected to a significant level of hoop stress. A segment should be considered susceptible if it has sustained an in-service or hydrostatic test failure where SCC is identified as the cause. A segment should also be deemed susceptible to SCC if evidence of arrays of cracks is discovered as a result of running an ILI crack detection tool and verified during pipe surface examinations. For assistance in determining whether a segment is susceptible to SCC, a pipeline operator is advised to consult such documents as OPS-TTO8, NACE SP0204, the Canadian Energy Pipeline Association’s (CEPA) SCC Recommended Practices, and other standards such as ASME STP-PT-011, Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas. Although the different approaches for the detection and assessment of SCC apply data integration to varying degrees, it is particularly important in regards to SCCDA.

A.5.1.2 SCC Characterization

Since it has been observed that SCC can be superficial (the occurrence of shallow, non-propagating cracks), the designation of “noteworthy” SCC should be used to clearly communicate the threshold for moving from a nominal monitoring phase into an active assessment and mitigation phase on a particular pipeline asset. Noteworthy as defined in ASME STP-PT-011, Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas, with the inclusion of a pure depth criteria, represents an enhancement of the term “significant” that was originally defined by CEPA regarding SCC and then adopted in the NACE SP0204. The importance of the pure depth criteria is that it encompasses the potential for short deep cracks associated with high pH SCC. Both ASME STP-PT-011 and CEPA’s SCC Recommended Practices provide a further delineation of the crack severity into a ranking, with the ASME criteria providing more clarity through its reference to failure pressure.
It is important to understand that the effective management of SCC will not be solely achieved through strict adherence to a standard. Rather, the operator managing the presence of noteworthy SCC needs to develop a program in consideration of the specifics of the pipeline and the limitations of the assessment techniques and technologies as applied. The effective management of noteworthy SCC typically requires periodic assessment via hydrostatic testing or ILI using a crack-detection tool. Reassessment intervals can be calculated by the method applied to anomalies with linear crack growth rates discussed in 10.2 and Annex D.

In-the-ditch inspection for SCC cracks requires a clean surface and the use of an appropriate NDE method (e.g. magnetic particle inspection). Where blast media is used in surface preparation, care should be taken to not peen the cracks shut prior to inspection.

ILI technologies are available that detect and evaluate SCC within reasonable bounds. Limitations inherent in the ILI technology and data interpretation lead to some challenges in the detection and characterization of SCC. For information on ILI technologies for assessing SCC, refer to API RP 1176.

A.5.2 Other Forms of Environmental Cracking

Pipelines that transport sour service products may be susceptible to other forms of cracking including sulfide stress cracking (SSC), hydrogen-induced cracking (HIC), or stress-oriented hydrogen-induced cracking (SOHIC).

Sulfide stress cracking is a form of hydrogen embrittlement that can affect a line pipe steel exposed to hydrogen sulfide and water while the material is subjected to tensile stress. A cathodic reaction in the presence of hydrogen sulfide and water can allow atomic hydrogen to diffuse into the steel. Normally, this will not affect the base metal of a line pipe steel, but if weldments on the pipe have created heat-affected zones with hardnesses of Rockwell C 22 or more, hydrogen cracking of the microstructure may occur. The phenomenon can be mitigated by preheating the material before welding or by post-weld heat treatment to eliminate zones of high hardness. Treatment of sour crude oil to eliminate free water and/or the use of an inhibitor to prevent the cathodic reaction may be an effective way to prevent the occurrence of SSC.

HIC and SOHIC are also threats associated with the transportation of sour crude oil containing water and are forms of SSC. The main characteristic of HIC is that diffusing atomic hydrogen tends to recombine into molecular hydrogen at manganese sulfide inclusions in the steel. The inclusions tend to “blister,” and hydrogen cracks will then propagate through the wall thickness from one inclusion to another in stepwise fashion. SOHIC has a similar appearance and is caused by the same cathodic generation of atomic hydrogen, but the presence of manganese sulfide inclusions is not necessary for SOHIC to occur. The stepwise cracking instead begins at planes of weakness parallel to the surfaces of the plate. Hence, SOHIC may occur in steels that have been purposely manufactured with low sulfur to prevent the formation of manganese sulfide inclusions. Unlike SSC, both HIC and SOHIC can occur in the normal line pipe material; high hardness is not necessary. Prevention of HIC and SOHIC requires either removal of water or the introduction of an inhibitor that prevents the cathodic reaction between water and hydrogen sulfide.

More information about the phenomena of SSC, HIC, and SOHIC may be obtained from the following:

— NACE MR0175/ISO 15156;


A.6 Manufacturing Defects (Defective Pipe Seams Including Hard Heat-affected Zones and Defective Pipe Including Pipe Body Hard Spots)

Seam integrity for line pipe material with a longitudinal seam made by means of double submerged arc welding (DSAW), helical seam double submerged arc welding (HSAW), or high-frequency welded electric resistance welding (HF-ERW) manufactured after about 1980 is usually not a more significant concern than overall pipeline integrity. For more information on manufacturers of ERW and other types of pipe, see History of Line Pipe Manufacturing in North
America. Pipeline operators should be aware that the seam characteristics of some types of older line pipe materials, particularly furnace lap welded (LW) pipe, low-frequency welded electric resistance welding (LF-ERW) or FW pipe, and “susceptible” HF-ERW (see next two paragraphs) may require a special assessment of seam integrity. See API TR 1179 for guidance on hydrostatic testing for seam integrity. The concerns with these materials are further detailed within API RP 1176 but include:

— inherently low fracture toughness within the seams,
— higher likelihood that the seams will contain defects due to the nature of the hot-rolled skelp from Bessemer or open-hearth processes,
— nondestructive seam inspections that may have limited capabilities,
— manufacturers' hydrostatic tests that frequently achieved a hoop stress less than 90 % of SMYS, even including end effects.

Cracks, pits, scabs, slivers, and laminations in the body of the pipe may arise from the manufacture of pipe skelp or the manufacture of line pipe, or both. These include longitudinal or helical seam anomalies which are usually crack-like. Definitions and descriptions of these types of anomalies appear in API 5T1. The user should refer to that document for the standard definitions of these anomalies and imperfections. If any such anomalies are not found by means of the manufacturer's hydrostatic test or nondestructive examinations or both and they are not eliminated by the initial preservice hydrostatic test of the pipeline, they will remain as anomalies in the pipeline. Frequently, such anomalies are revealed by ILI or hydrostatic retests. Having survived an initial preservice hydrostatic test to a level of at least 1.25 times MOP, these types of anomalies will be non-injurious to pipeline integrity unless they are subject to enlargement by pressure-cycle induced fatigue or interaction with other defects (see A.5.1).

A.6.1 Pressure-Cycle-Induced Fatigue

As mentioned above, some HF-ERW pipe materials may be susceptible to the same seam integrity threats that affect LF-ERW and FW pipe. Until sometime in the early 1980s, most HF-ERW pipe was made from the same type of skelp as LF-ERW and FW pipe, that is, skelp hot-rolled from open-hearth, ingot-cast steels with sulfur contents typically in the range of 0.015 % to 0.030 % by weight. These materials were often characterized by high inclusion contents that could lead to the formation of “hook” cracks adjacent to the bondline of the ERW seam. Hook cracks are one of the primary initiators of pressure-cycle-induced fatigue (discussed below). The threat of pressure-cycle-induced fatigue in HF-ERW pipe may exist if any one of the three following conditions has occurred:

1) Pipeline has experienced failure due to pressure-cycling-induced fatigue.
2) Hydrostatic test records indicate numerous seam splits.
3) Pressure cycle spectrum is known to have caused fatigue failures in other types of pipe subjected to similar circumstances.

Therefore, these types of HF-ERW materials should be considered possibly susceptible to pressure-cycle-induced fatigue and should be treated as potentially having the same seam integrity assessment needs as LF-ERW and FW pipe materials.

Pressure-cycle-induced fatigue crack growth of seam-related manufacturing anomalies is one concern with a LF-ERW material, a direct current welded electric resistance welding (DC-ERW) material, a FW material, or a susceptible HF-ERW material.
A.6.2 Hook Cracks

As steel manufacturers in the early 1980s changed over to basic oxygen steel making (which is capable of reducing sulfur contents to levels below 0.01 % by weight) and continuous casting, the quality of the skelp used to make ERW pipe greatly improved. Alternatively, some manufacturers used sulfide shape control to prevent the formation of elongated manganese sulfide inclusions that contribute to the formation of hook cracks. These types of improvements along with improved seam inspection by the manufacturers greatly reduced the potential for hook cracks ending up in finished line pipe. Thus HF-ERW pipe made after the early 1980s generally will not have the same seam integrity issues as HF-ERW pipe made prior to that time. HF-ERW materials that generally are not susceptible to the problems associated with hook cracks would be characterized by low sulfur contents (<0.01 % by weight) or the absence of elongated sulfide inclusions, or both, as viewed on a metallographic section. When available, a review of the vintage and manufacturing history of HF-ERW materials may help determine the potential for the existence of hook cracks. Factors such as being manufactured prior to 1980, skelp being rolled from an open-hearth furnace steel, sulfur content being in excess of 0.01 % by weight, low toughness being exhibited in Charpy impact tests in the vicinity of the ERW bond line, or elongated sulfide inclusions appearing in a metallographic section would tend to indicate potential susceptibility to hook cracks. If the existence of hook cracks is confirmed and the operational pressure cycles are considered to be relatively aggressive, the operator should consider the particular HF-ERW material as “susceptible” and implement a program of seam integrity assessment for that pipe.

A.6.3 Hard Spots or Hard Heat-affected Zones

Hard spots are regions of the pipe material that possess hardness levels (and ultimate tensile strength levels) significantly higher than the ranges of hardness that characterize the normal parent pipe material. Hard spots may exist as local round or oval areas in the body of the material or in a narrow zone immediately adjacent to the seam bond lines of some older-vintage ERW materials. Both types of hard zones arise from excessive cooling rates applied to the zones as they were cooled from temperatures above 777.8 °C (1432 °F) during the manufacturing process. The round or oval hard spots in the pipe body were most likely to be found occasionally in older Grade X52 materials made in the late 1940s or early 1950s. The hard zones adjacent to ERW seams were most likely to be found occasionally in materials of Grade X46 and Grade X52 manufactured prior to 1960.

The hazard associated with hard zones or hard spots is that if their hardness levels exceed 350 Hv10 (33 to 35 Rockwell C), they are prone to hydrogen induced cracking in the presence of atomic hydrogen (that is, hydrogen ions in solution, not hydrogen gas, H2). Sources of atomic hydrogen arise internally if sour crude is transported and externally from cathodic protection with sour crude being the more aggressive of the two environments. Service failures have been known to occur as a result of exposure of hard spots or hard zones to either of these environments.

Neither hard spots in the body of the pipe nor hard heat-affected zones adjacent to the bond line can be satisfactorily addressed by hydrostatic testing. Prior to the formation of any cracking in these materials, no defect exists that would cause them to fail in a hydrostatic test. If and when they begin to crack after sufficient exposure to atomic hydrogen, the cracking can lead to rapid or even immediate failure. Therefore, there is no way to apply hydrostatic testing in a timely manner.

A.6.4 Furnace Lap Welded (LW) Pipe

If a segment comprised of furnace LW pipe has never sustained a seam-related failure and it has been tested to at least 1.25 times MOP, the need for assessment is based on whether the MOP exceeds 30 % of SMYS. Assessment is not needed if the MOP does not exceed 30 % of SMYS. Assessment is also not needed if the MOP does exceed 30 % of SMYS but does not exceed 72 % of the manufacturer’s hydrostatic test pressure. If none of these conditions is satisfied, the operator should perform a baseline seam integrity assessment to ensure that no seam manufacturing flaws could cause a failure at the MOP. Periodic seam integrity assessment is probably not necessary for segments comprised of furnace LW pipe. There is insufficient knowledge concerning the possible modes of time-dependent deterioration of the furnace LW materials. While no known instances of failure have occurred from either SSWC or...
pressure-cycle-induced fatigue, in-service failures of furnace LW pipe materials have occurred after such materials have been pressure tested to levels in excess of their MOP. Some of these, perhaps all of them, may be attributable to accidental over-pressurization. The operator of a LW pipeline that is operated at a pressure level that exceeds 72% of the manufacturer’s hydrostatic test pressure should monitor the condition and service history of the pipeline, and consider periodically assessing its integrity if the operating history suggests that in-service seam-related failures have taken place after a hydrostatic test to at least 1.25 times the MOP. ILI tools designed for seam weld inspection, while capable of detecting some anomalies in lap welded pipe, have poorer overall detection and sizing capabilities. Inspection challenges associated with small diameter and low pressure pipelines can also limit the success of ILI for lap welded pipe.

A.6.5 Determining Need to Conduct Seam Integrity Assessment

To determine whether a special seam integrity assessment is needed, the pipeline operator should review the below attributes for all pipeline segments as part of their IMP. Additional guidance for prioritizing pipe segments for seam integrity assessments can be found in API RP 1176, Section 6.3, “Manufacturing Defects Associated with Longitudinal Seams”. This document provides a flowchart to determine a system prioritization of low, medium, or high. High priority is where a pipeline has had a time-dependent failure mechanism cause service or test failures and has a remaining fatigue life of 10 years or less. Medium priority is where a time-dependent failure mechanism has not been observed but other conditions exist that make a future seam integrity issue more likely. Low priority is where a time-dependent failure mechanism has not been observed and the other conditions are such that a future seam integrity issue is unlikely. The prioritization takes into account the following factors of the longitudinal seam:

— year of manufacture;
— service or hydrostatic test failure history related to grooving corrosion or fatigue
— operating stress level;
— hydrostatic test pressure levels;
— coating condition and CP effectiveness;
— pressure cycle aggressiveness.

A.7 Construction and Fabrication Defects

Construction defects include girth weld defects, rock dents, installation damage, flaws in fabricated fittings or branch connections, bending mandrel marks, ripples, buckles, and wrinkle bends.

Electric arc girth welds seldom cause a pipeline to fail without other threats being present. Usually when a girth weld has failed it is because the pipeline has been subjected to some extreme longitudinal load such as that from a landslide or washout. There are some exceptions that cause girth welds to remain on the threat list. First, acetylene girth welds, an obsolete joining technique employed in some old pipelines, have had a significant number of failures. Second, some modern higher-strength pipeline steels can have lower strengths in the heat-affected zone (HAZ) adjacent to the girth weld. Overly strong weld metals and pipe can concentrate strain into softened HAZ regions resulting in an increased failure rate due to small anomalies, joint-to-joint misalignment and weld transition profiles when wall thicknesses are different. Therefore, girth welds, except as noted, are usually not a significant threat to pipeline integrity. As part of its IMP, a pipeline operator that operates a pipeline fabricated by means of acetylene girth welds should establish a program of monitoring soil stability and riverbank erosion for signs of movement or change that might add stress to such welds. Such an operator should be prepared to mitigate any situations where it appears that the acetylene welds might be experiencing added stress.

Although the use of an intentional wrinkle bend (a buckle allowed to form intentionally during cold field bending) is prohibited by safety codes such as ASME B31.4, some may exist in older pipelines designed prior to the existence of
consensus safety codes. These will show up during ILI runs. Removal of wrinkle bends is recommended, but if they cannot be removed, the operator should periodically check the stability of the soil in their vicinity since movement of the pipeline at a wrinkle bend is one reason for its failure.

Ripples and bending mandrel marks are considered non-injurious to pipeline integrity. A criterion for acceptable ripple height is contained in ASME B31.4. Buckles are anything that falls outside the limits on ripple height, and any such buckle should be repaired.

Flaws in fabricated fittings are usually not something that can be reliably detected in an integrity assessment. Therefore, a pipeline operator should have a quality control program that ensures the satisfactory fabrication and inspection of fabricated fittings.

Some procedures used in the past to repair pipe defects are not recommended today. For example, puddle welding was used to replace lost or damaged metal and restore pipe continuity. Puddle welding should not be confused with the current deposited weld metal technology, which has been shown to produce repairs of acceptable quality.

Patches and half wraps may have been used to repair leaking pipelines. These repairs are no longer recommended for high-strength line pipe because of the potential weak point at the juncture between the longitudinal fillet weld and the patch or half wrap.

An arc burn results from momentary contact between a welding electrode and a pipe or fitting that leaves little or no weld metal, but may cause local pitting and almost always results in a small area of damaged microstructure at the point of contact. Because of their small size, arc burns are generally not a threat to pipeline integrity. If arc burns with no indications of cracking are discovered on a pipeline as the result of an integrity assessment, they need not be repaired. However, they are usually a sign of poor workmanship and should not be tolerated on any new construction.

A.8 Equipment Failure

Pumps, valve, seals, o-rings, meters, pressure switches, temperature gauges, prover loops, scraper traps, strainers, truck loading racks, etc. are types of equipment found mostly at terminals and pump stations. These components are subject to occasional malfunction and/or failure, and they may in certain cases cause an unintended release. A pipeline operator's facility IMP should address the periodic inspection and routine maintenance of such equipment with the intent of preventing equipment failures. Attention should be paid to known mean times to failure for commonly used components, and a timely replacement of parts or units should also be part of the facility's IMP.

A.9 Mechanical Damage

A.9.1 Mechanical Damage Resulting in Immediate Failure

This threat arises from excavation, drilling, boring, farming, or other soil moving or removal activities where the mechanical equipment being used comes in contact with a buried pipeline causing it to leak or rupture. Other failures have also been known to occur in conjunction with someone imposing a heavy load on the soil over a pipeline. Immediate failures have occurred as the result of vandalism as well. Preventive measures such as one-call systems, locating and marking for a potential excavation, monitoring of any excavation on or near a pipeline, public awareness campaigns, and aerial or ground surveillance are intended to prevent such occurrences. When an excavator makes a one-call and the pipeline operator responds appropriately, the risk of such an incident is small. Firm lines of communication between the excavator and the pipeline operator and continued diligence on the part of both is essential to minimize the chances of an incident or near miss. A more perplexing problem arises in conjunction with land occupants and others who initiate excavations without making a one-call and without notifying the operator of the pipeline. A pipeline operator should consider the value of occasional communications with land occupants and other potential excavators to educate them of the risks associated with excavating around a pipeline and encourage them to make a one-call before excavating even on their own land. In addition, a pipeline operator should conduct regular aerial or ground patrols of their right-of-ways except in remote or inaccessible areas.
A.9.2 Mechanical Damage Resulting in Delayed Failure

This threat arises from excavation, drilling, boring, farming, or other soil moving or removal activities where the mechanical equipment being used comes in contact with a buried pipeline leaving a dent or dent and gouge that are not severe enough to cause it to leak or rupture immediately. Dents arising from lowering a pipeline onto a rock or from pushing a rock onto the pipe during backfilling also fall into this category. If the anomalies created in this manner are not discovered or if they go unreported, they may become more severe with the passage of time such that eventually they cause a leak or a rupture. Factors that may cause them to become more severe with the passage of time include, external corrosion, SCC, further creep of the defect or settlement of the pipeline, and pressure-cycle-induced fatigue. A hydrostatic test does not guarantee that such a threat will be neutralized unless the anomaly causes a leak or a rupture during the test. ILI metal loss tools and geometry tools, especially if used in combination, are the best ways to locate and mitigate any such anomalies. A pipeline operator’s IMP should address using ILI for that purpose, and it should contain criteria for deciding if and when a discovered anomaly should be excavated and examined.

A.10 Incorrect Operations

The threats to integrity from incorrect operations include but are not necessarily limited to accidental overpressurization; failure to design properly for or limit surges; improper closing or opening of valves; overfilling tanks; exercising inadequate or improper corrosion control measures; misinterpreting alarms or leak indications; and improperly maintaining, repairing, or calibrating piping, fittings, or equipment. A pipeline operator should create and maintain an operating and maintenance manual and make sure that all operating and maintenance personnel are well-versed in its contents and properly trained and equipped to comply with its requirements. Pipeline operators should consult documents such as API RP 1168 and ASME B31Q, Standard for Pipeline Operator Qualification with regard to proper training for pipeline operators.

A.11 Weather and Outside Force Related Defects (Cold Weather, Lightning, Heavy Rains or Floods, and Earth Movement)

Cold weather, lightning, floods, landslides, subsidence, earthquake, etc. are known causes of pipeline failures. Since these are random, often unpredictable events, an operator should establish a preventive and mitigative program to minimize the risk of a pipeline failure from such phenomena. API RP 1133 should be referenced for industry best practice.

Cold weather can cause water in liquid pipelines to freeze in low points of a pipeline system resulting in cracked piping and valves. Release of the product then occurs when the ice thaws and releases the product through broken fittings, valves and piping. Plugged bottoms of valves are a particular risk if water can seep by the valve and is trapped by the plug then expands breaking the valve.

Lightning strikes and high-voltage power line breaks have the potential to cause significant damage to pipelines.

Heavy rains and flooding can create various hydrotechnical hazards (exposures, landslides, dynamic loading, debris impacts and vortex-induced vibration), to susceptible pipeline crossings of water ways as further detailed in API RP 1133.

Earthquakes and earth movement—Seismic monitoring of known geologically unstable areas can assist in providing warning of earth movement. Strain gauges can monitor the strains being applied to the pipeline as a result of gradual earth movement.

An initially non-injurious anomaly arising from any one of the above hazards can grow into an injurious defect via fatigue. Repeated cycles of stress are known to cause defects above a certain threshold size to grow, and if the growth continues long enough the defect can cause structural failure. The types of pipeline anomalies that are considered potentially susceptible to growth by pressure-cycle-induced fatigue include longitudinally oriented manufacturing defects, stress corrosion cracks, gouges, gouges in dents, and stress risers associated with poorly
fabricated repairs. The degree of this threat is strongly dependent on the initial size of the defect, the aggressiveness of the pressure cycles in terms of stress range and frequency, and the effective crack-growth rate. Details are provided in Section 9 and Section 10 on how an operator might evaluate the degree of threat presented by pressure-cycle-induced fatigue.

### A.11.1 Seismic Activity

Ground movement resulting from seismic activity may put the integrity of a pipeline in the vicinity of the movement at risk. As such, a Seismic Response Protocol should be developed to describe the processes and procedures for recognizing and responding to seismic events. This protocol may provide guidance on seismic event discovery methods, response thresholds, field and control center response procedures, assessment guidelines and startup criteria.

Seismic activity may be discovered through a variety of methods including: direct detection by field personnel, alerts from the USGS Earthquake Hazard Program (EHP), and various instrumentation alarms in SCADA (such as pump vibration monitors, strain gauges, or leak detection systems). Of these discovery methods, the first two can easily be correlated to seismic activity and allow for an actionable seismic response protocol.

USGS data can be analyzed to determine the magnitude and epicenter of the earthquake in relation to an operator's assets. If established thresholds are exceeded, corresponding response procedures should be keyed and notifications made to the appropriate personnel.

Some suggested seismic magnitude threshold levels for Shutdown and Visual Assessment response zones are described in Table A.1. Note that the response zones are more conservative for pipelines crossing through liquefiable soils. This is because the pipe will move differently in liquefied soils vs non-liquefiable soils and at the boundary between the two soil types, there is increased likelihood of pipeline damage. Responding at lower magnitude levels should be considered in areas containing critical locations, pipeline segments that contain pre-1970s construction and pipeline segments that contain acetylene girth welds. If the epicenter of the earthquake is within 1 mile of an active fault line (documented movement in the last 10,000 years), the response zone for any pipelines crossing that fault line should match that of the liquefiable soil criteria outlined in Table A.1 regardless of soil type. Consulting a geotechnical firm familiar with pipeline and terminal assets can be helpful in establishing appropriate thresholds, identifying areas of liquefiable soils, and determining areas of active fault lines.

<table>
<thead>
<tr>
<th>Table A.1—Example Seismic Activity Response Criteria</th>
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<tbody>
<tr>
<td><strong>Magnitude</strong></td>
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<tr>
<td>-------------</td>
</tr>
<tr>
<td>LIQUEFIABLE SOIL</td>
</tr>
<tr>
<td>5.0</td>
</tr>
<tr>
<td>6.0</td>
</tr>
<tr>
<td>7.0+</td>
</tr>
<tr>
<td>NON-LIQUEFIABLE SOIL</td>
</tr>
<tr>
<td>5.0</td>
</tr>
<tr>
<td>6.0</td>
</tr>
<tr>
<td>7.0+</td>
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</tbody>
</table>

**EXAMPLE**  A Mw 5.4 earthquake occurs near a pipeline system in Oklahoma (see Figure A.1). Pipeline A is within 6 miles of the epicenter. Pipeline B is within 13 miles of the epicenter. Based on the threshold levels described in Table A.1, a minimum response should include immediate shutdown of Pipeline A and initiation of a visual assessment of Pipeline B. Additional records investigations should take place for both pipelines. If Pipeline B is known to have vintage or acetylene girth welds, a shutdown should also be considered until the visual inspection can be completed.
Whether the alert is made via an automated system or by field personnel, procedures should be developed to either shutdown and/or perform visual assessments on assets in the affected area, and within a reasonable amount of time (72 hours for visual assessment). Visual assessments may include the following:

a) Examine the pipeline ROW, especially at areas of newly exposed pipe or known fault crossings and landslide areas, for:

- ground cracking,
- soil settlement,
- land movement (landslides),
- fault shifting.
b) Inspect aboveground assets such as pipe transitions and supports, flange connections, equipment foundations, and tank shells for evidence of the following:

- cracking,
- buckled or bent pipe,
- shifted equipment,
- bent or loose tubing,
- abnormal noise or vibration.

An operator should consider consulting a geotechnical or structural engineer to evaluate the pipeline if damage is apparent and the integrity of the pipeline is unknown.

A standup pressure test can be useful to help verify pipeline integrity prior to a restart. If the assets show no visible damage and there are no other indicators of integrity risks (no further pressure, leak detection or other alarms in SCADA), consideration can be given to restarting the assets. After startup, all conditions shall be monitored closely to ensure continued safe operation.
Annex B
(informative)

In-line Inspection Technologies

B.1 Metal Loss Tools

ILI tools are available for locating and sizing internal and external corrosion-caused metal loss. The generic technologies preferred for this purpose are:

- high-resolution axial field MFL tools,
- transverse flux MFL (inclusive of circumferential or helical field MFL) tools,
- ultrasonic compression wave tools.

Axial Field MFL Tools—This type of tool establishes a direct magnetic field circuit using the pipe wall as a conductor. The magnetic field is oriented parallel to the axis of the pipe. Metal loss within the pipe causes flux to leak outside or inside the pipe wall, and arrays of sensors are used to detect the flux leakage. Most tools use Hall-element sensors that can detect the absolute flux field even when the tool is not moving. Some older tools use coil-type sensors that rely on movement of the tool through the flux leakage field to induce a detectable voltage in the coil. The physical dimensions of the metal loss are inferred from the size and shape of the flux disturbance. The axial orientation of the flux field makes the tool particularly sensitive to the circumferential width and depth of an anomaly but less sensitive to its axial length. The length is usually inferred from the location of the beginning and end of the flux disturbance. In areas of multiple metal loss anomalies, the accuracy of the sizing may vary from vendor to vendor depending on the criterion a particular vendor uses for "clustering" the anomalies.

The magnetic phenomena are independent of the type of fluid in the pipe, as product does not affect the amount of magnetism that is coupled into the pipe through brushes or skid plates. The amount of magnetism is affected by debris and deposits which can increase the separation or liftoff between the steel brushes or skid plates and the pipe. The tools are fairly insensitive to velocity over the range of typical liquid pipeline flow velocities; tools with coil-type sensors must be moving at some minimum velocity to work. Axial field tools almost always include a mechanism to detect when the metal loss is internal and when it is external. An evolving variant of this type of tool uses bi- or tri-directional hall elements which measure magnetic flux levels in two or more directions. It is believed that the use of this technology will improve quantitative measurement of clusters of pits and complex corrosion profiles.

Axial field MFL tools have poor capability to sense the presence of axially oriented crack-like anomalies, and are not particularly good at characterizing "narrow axial external corrosion," a particular type of external corrosion described in Annex A that is associated with the “tenting” of tape-type coating over the crown of a submerged arc seam weld. Such tools cannot be relied upon to detect SSWC either. When used in conjunction with adequate verification excavations to evaluate sensitivity these tools have been found to be highly reliable for detecting and characterizing the severity of wide corrosion-caused metal loss (i.e. remaining strength of the pipe) and other volumetric anomalies but generally have decreased sensitivity to mechanical damage gouges due to the cold working of the metal beneath the gouge, which affects the magnetic field. Axial field MFL tools are probably the most frequently used type of ILI tool.

Transverse (Circumferential or Helical) Field MFL Tools—These tools employ a direct magnetic field to detect flux leakage at metal loss anomalies in much the same manner as the axial field MFL tools. The main difference is that the field is oriented circumferentially instead of axially. This makes the technology more sensitive to the axial length and less to the circumferential width of the anomaly. Depths of anomalies are also detectable by this method. The circumferential orientation of the flux makes it possible to detect narrow axial external corrosion, SSWC, and some types of crack-like anomalies that arise from pipe manufacturing (e.g. ERW seam anomalies). The user of this type of tool may be able to better characterize the axial lengths of corrosion-caused metal loss (particularly for narrow axial
external corrosion) for the purpose of calculating the effect of an anomaly on remaining strength. Generally, these tools are capable of identifying the orientation of the long seam, even in ERW pipe. Calculating the remaining strength at a bond line anomaly such as SSWC by means of standard remaining strength equations for metal loss (i.e., RSTRENG, ASME B31G) is not recommended. If accurate values of depth and length are known, then a remaining strength for a SSWC anomaly ostensibly could be calculated from an operator-selected crack equation. This requires careful consideration as the bondline toughness values can vary significantly from joint to joint.

Ultrasonic Compression Wave Tools—Ultrasonic compression wave tools are equipped with arrays of individual ultrasonic transducers that transmit and receive acoustic energy through the transported fluid in the pipeline. This is an important point because the tools may work better in some fluids than others. They do not work at all in natural gas, and their performance may be degraded in some lighter hydrocarbons. Two reflections of the signal from each transducer are transmitted back to the transducer: one from the ID surface of the pipe and one from the OD surface. The difference in arrival times is calculated from the wave speed and constitutes a direct measure of the wall thickness at a point. If the arrival time of the first reflection is longer than the arrival time for the standoff distance from the normal ID pipe surface, the corrosion is assumed to be internal. If the arrival time of the first reflection is the same as the time for the standoff distance and the arrival time of the second reflection is shorter than the arrival time from the normal OD surface, the corrosion is assumed to be external. While these tools can be quite accurate and can give thickness along the length of an anomaly, they have some limitations. Wax or debris or an irregular surface can prevent a recapture of the return wave resulting in no useful information. High tool velocity within the pipeline can degrade the signal. At bends the tool sensor standoff distance can change, resulting in misinterpretation of the signal. At dents with certain curvature, the reflection can be lost resulting in an area of no inspection. If the pipe is significantly laminated, the signal can be almost entirely reflected by the lamination resulting in unreliable inspection for external metal loss behind the lamination. These tools have been found to give highly reliable detection and characterization of corrosion-caused metal loss, and they have been widely used.

B.2 Crack Tools

ILI tools are available for locating and sizing cracks and crack-like anomalies. The generic technologies available for this purpose are:

— ultrasonic angle beam tools,
— electromagnetic acoustic transducer (EMAT) tools,
— transverse flux MFL (inclusive of circumferential or helical field MFL) tools.

API RP 1176 contains a summary of the commercial ILI tool types and utilization considerations to detect cracks.

B.3 Geometry Tools

ILI tools are available for locating and sizing geometric features such as dents, ovalities, and buckles. The generic technologies available for this purpose are:

— caliper tools,
— high-resolution geometry tools.

Caliper Tools—Caliper tools employ mechanical arms that contact the inner wall of a pipeline at discrete locations. As the tool moves along the pipeline, the arms deflect in response to physical irregularities in the circular shape of the pipe. The recorded deflections reveal the circumferential deviations from circularity and the manner in which they vary along the axis of the pipe. Using this type of tool, a pipeline operator can locate and characterize dents, ovality, and buckles in a pipeline segment. The level of accuracy depends on the number of mechanical arms employed and the number of data channels recorded. At a minimum caliper tools can indicate the maximum height of the geometric...
anomaly and its overall length. Generally, caliper tools are not sufficiently sensitive to determine curvature of the pipe wall in the vicinity of a geometric anomaly.

High-resolution Geometry Tools—These tools provide measurements of the position of the centerline and ID surface of the pipe with a higher degree of accuracy than most caliper tools. The physical locations of the pipe wall may be sensed by electromagnetic or acoustic signals, and in some tools both position sensors and mechanical arms are used. The accuracy of the data usually is sufficient to indicate the curvature of the pipe wall in the vicinity of a geometric anomaly. A pipeline operator using a high-resolution geometry tool may be able to estimate metal strains as well as to determine the height and length of the anomaly. In such cases, the sharpness of the anomaly which bears on its potential effect on pipeline integrity can be determined without excavating.

B.4 Pipeline Profile and Alignment Tools

Inertial guidance tools, utilizing very high accuracy optical gyroscopes, are available for detecting changes in profile and changes in alignment as well as the pipeline centerline that can then be used to locate pipeline equipment and defects in geographical/photographical based systems. This type of information is useful for locating areas of possible landslide or settlement that could threaten the integrity of the pipeline as well as looking for coincident geographic features that would lead to root causes of certain threats being uncovered e.g. low points at crossings coincident with internal corrosion. Note that having a baseline profile and alignment is necessary to determine from a subsequent inspection whether a change has occurred.

B.5 Combination Tools

ILI vendors are increasingly offering ILI tools with multiple inspection technologies on a single tool chassis. These tools offer reduced inspection costs and data that are fully integrated between the technologies on-board. This capability is particularly helpful in identifying certain threats, such as mechanical damage anomalies (gouge and dent combinations created by mechanical excavating equipment that require multiple inspection technologies to properly identify and characterize). Some vendors offer a modular approach to tool design that allows operators the flexibility to pick which inspection technologies they want on-board. Sometimes the combination of these features in one tool results in the vendor being able to provide a more accurate depiction of the combination anomaly such as a dent containing metal loss or better characterizing an anomaly class such as a gouge versus metal loss or SSWC.

B.6 Additional ILI Technologies

Below are some additional ILI technologies that may address various needs:

A two magnetic field level approach to MFL, either low field (below saturation) or residual, can detect pipe material property changes. This can be useful for the detection and assessment of hard spots, gouging in dents, or localized residual stresses.

B.7 Using Multiple ILI Technologies

Choosing the most appropriate ILI technology is an important decision in assuring the integrity of a pipeline. An example tool selection process is illustrated in Figure B.1 and described next. An ILI program should start with a bore diameter or geometry inspection to assure the safe passage of tools to assess anomalies such as corrosion and cracking. This is typically followed by an axial MFL tool for the detection of metal loss. The results of the inspections can help define future tool selection. Since axial MFL has limitations assessing narrow axially aligned corrosion as discussed in Section A.1, a multi-tool approach would include choosing a different tool for a future inspection. A circumferential MFL tool would be appropriate in this case to assure axially aligned corrosion anomalies were not missed or undersized. This circumferential MFL tool can be used to address other threats associated with the longitudinal seam. Another situation could be use of an ultrasonic wall thickness tool after an axial MFL tool. Examples for this approach include pipelines that have a large number of corrosion anomalies of significant depth or when axial MFL results are not meeting specification. An analysis of the results may produce a recommendation that the axial MFL inspection be repeated in the next cycle. This approach may be used to establish a corrosion growth
rate. The results from secondary tool inspections can lead to the selection of alternative tools for future inspections. For example, if a circumferential MFL tool detects anomalies in a vintage ERW seam that are confirmed in the ditch, additional inspection with a more sensitive ultrasonic crack tool may be appropriate. Tools that may be used, as detailed in API RP 1176, include ultrasonic shear wave and EMAT technology. Since anomaly type, size and density along with operational considerations are just some of the variables associated with ILI, no single approach is best for all pipelines. Using multiple ILI technologies can improve integrity by more completely assessing anomalies.

![diagram](falatghareh.ir)

**Figure B.1—An Example Tool Selection Process**

**B.8 Considerations for Interacting Threats**

**B.8.1 Internal or External Corrosion and Cracking Threats**

The presence of internal corrosion or external corrosion in the same area as a cracking threat, either EAC (typically SCC), or manufacturing defects (seam weld anomalies) challenges detection technology and assessment methods. Internal or external corrosion can obscure the crack response for some ILI technologies and affect the depth measurement accuracy for these technologies. Inspection methods must define the length of the remaining ligament for the crack tip to the far wall, which could be the original surface or corroded region. Corrosion can affect ILI and external NDE in three ways:

1) Rough surfaces and internal debris associated with corrosion can interfere with the coupling of ultrasonic energy into the pipe.

2) Signals returning from interacting cracks and corrosion can combine, adding to the complexity of determining crack depth.

3) Inspection methods may provide the size of the crack with or without factoring in the metal loss depth.
Although transverse flux MFL tools run in association with an EMAT tool are primarily used to assist in discriminating steep-sided corrosion, they also identify the presence of any coincidental or interacting corrosion. An important aspect of this is that when the EMAT tool identifies cracking features in corrosion, the reported depth is inclusive of the corrosion depth. Additionally, certain feature classes detectable by EMAT may not exhibit a magnetic discontinuity (cold welds) and are therefore undetected with MFL.

Shear wave UT combined with compressive wave UT can identify the interaction of corrosion and cracking, but the resolved depth of the cracking would be determined in consideration of the depth of corrosion (i.e. the depth that the corrosion adds will depend on the morphology of the corrosion).

### B.8.2 External Corrosion Interacting with Internal Corrosion

As both internal and external metal loss are reported by the same technology within the same ILI dataset, the review for their interaction is integral to the ILI vendor’s analysis process and would be addressed in the reporting.

Data analysis can be complicated when internal and external metal loss anomalies are coincident to each other. For MFL data, coincident ID and OD corrosion would be reported as internal. When an ILI calls both types of corrosion in a region where interaction could occur, additional analysis and assessment may be required. For compression wave UT data, coincident ID and OD can be reported separately, however, there is the potential for reduced accuracy since the amount of missing data due to echo loss may increase.

### B.8.3 Mechanical Damage Interacting with External Corrosion, Internal Corrosion, or EAC

Mechanical damage often damages the pipeline coating and creates a local stress in the pipeline which makes it more susceptible to EAC, or external corrosion at the location of the damage. Threat interaction with external corrosion can occur where the deformation is sufficient to damage the coating and the cathodic protection is locally impaired. The increase in residual stress associated with the dent or gouge can also be sufficient to initiate and grow SCC at this location.

The combination of MFL and caliper technologies support dent with metal loss (i.e. gouge or corrosion) as a distinct reported feature type. There are approaches that have extended the capability of this combination by using the caliper sizing for screening, but then manually reviewing the MFL signal data for the presence of cracking. This approach has successfully identified circumstances where cracks were found in association with dents. Alternatively, cracking ILI technologies can be overlaid against the caliper data, however the probability of detecting cracks in dents by ILI may be reduced.
Annex C  
(informative)

Repair Strategies

C.1 General

Inspections conducted per the operator’s IMP will result in features that should be evaluated. Several of these will be classified as defects that will require repair and this annex provides guidance to develop repair strategies. The information provided in this annex should not be considered a complete summary of every type of repair, but an overview of some of the more frequently used techniques in the industry today. In the absence of detailed company procedures for pipe replacement or repair, ASME B31.4, ASME PCC-2, CSA Z662 or the PRCI Pipeline Repair Manual R2260-01R (Catalog L52047) should be consulted.

An effort has been completed that maps specific defects to appropriate repair strategies and provides a reference for individuals determining the appropriate repair strategy for a certain type of defect in a certain location (seam, body, and girth weld) of line pipe. This compilation document is only intended to be used as reference showing at a high level how the various industry standards and documents approach use of these repair methods. For details on the applicability of a specific repair method, refer to the individual documents referenced within.

ASME B31.4, Paragraph 451.6, Pipeline Integrity Assessments and Repairs, describes thresholds for repair of specific defects.

Title 49 CFR Part 195 describes rules for repair. The current rule states that repairs shall be made in a safe manner and are made to prevent damage to persons or property. This gives the operator the flexibility to use new or innovative repair technologies.

All repairs shall be made in a manner that complies with applicable safety codes and regulations.

C.2 Pipe Replacement

If a section of pipe is found to have a severe defect(s), or a steel reinforcement sleeve will not fit, or a composite reinforcement sleeve will not fit, the replacement of a defective section of pipe with another pipe section may be required. The replacement pipe should have the capability to carry the MOP of the pipeline safely, and it should be hydrostatically tested prior to commissioning to a four-hour-long pressure test to 1.25 times MOP while being visually monitored for leakage.

C.3 Re-coat

After an external anomaly has been evaluated and determined to not require a repair, the anomaly may be re-coated. After the pipe has been re-coated, the anomaly will once again be under the protection of coating and cathodic protection. If the pipe was previously coated and cathodically protected, some determination of the root cause of the corrosion anomaly should be made and mitigative measures taken so as to preclude recurrence or an increase in severity of the anomaly.

C.4 Pipe Sleeves

Steel full encirclement sleeves are one of the most widely used methods of general repair of defects in pipelines. In the early 1970s, the American Gas Association funded a major project on the effectiveness of various repair methods, with special emphasis on full-encirclement sleeves. This work showed that a properly fabricated sleeve will restore the strength of a defective piece of pipe to at least 100 % SMYS.
There are many types and configurations of steel full encirclement sleeves that can be used, dependent upon the configuration of the pipeline segment and the defect area to be repaired. Certain types of repair sleeves or their quality, while detectable by ILI tools, cannot be differentiated by the tool. For more information, see API 1176.

C.4.1 Type A Sleeves

A Type A sleeve consists of two halves of a pipe cylinder or two curved plates placed around the carrier pipe at the defective area and joined by welding the side seams via a full penetration butt weld, by fillet-welding an overlapping strap across the joint, or via a single fillet weld. The ends are not welded to the carrier pipe but should be sealed to prevent migration of water between the pipe and reinforcing sleeve. The resulting sleeve cannot contain pressure and can only be used on non-leaking defects. To be effective, the Type A sleeve should reinforce the defective area, restraining it from bulging radially as much as possible. Reduction in operating pressure while the sleeve is being installed makes for a more effective repair. This is also true for using incompressible resin filler in the annular space.

a) Advantages:
   — No welding to the carrier pipe is required.
   — Longitudinal welds can be made with cellulose rods, if necessary.
   — The repair is easily detected by a traditional magnetic metal loss ILI tool.

b) Disadvantages:
   — The repair is not recommended for circumferentially oriented defects.
   — It cannot be used to repair any leaking anomalies or anomalies that will eventually leak.
   — Dents not effectively filled with resin or dent filler may fatigue and crack.

C.4.2 Type B Sleeves

Another type of steel sleeve used to repair defects in pipelines is the Type B sleeve in which the ends are fillet welded to the carrier pipe. The Type B sleeve consists of two halves of a pipe cylinder or two curved plates fabricated and positioned in the same manner as a Type A sleeve. A Type B sleeve may contain pressure and/or carry substantial longitudinal stress imposed on the pipeline by lateral loads. In any case, it should be designed to safely carry the MOP of the pipeline. This type of sleeve can be used to repair leaks and strengthen circumferentially oriented defects. Sometimes Type B sleeves used to repair non-leaking defects are pressurized by hot tapping through the sleeve and the pipe to relieve hoop stress from the defective area. The Type B sleeve should be fabricated using full penetration welds for the side seam. Only Type A sleeves that have butt welded longitudinal side seams and that are designed to safely carry the MOP of the pipeline may be made into Type B sleeves by fillet-welding the ends to the pipe.

a) Advantages:
   — It can be used on most every type of anomaly, including leaking defects.
   — It can be used for circumferentially oriented anomalies.
   — The repair is easily detected by a traditional magnetic metal loss ILI tool.
   — Annular space between the sleeve and the carrier pipe is protected from corrosion.
b) Disadvantages:

— There is a potential for delayed cracking associated with the circumferential fillet welds if the welds are made while the line is in service using a non-low-hydrogen welding process.

— The quality of welding needed, and the heat sink conditions associated with the end fillet welds require that only skilled welders who are qualified to use low-hydrogen processes be used to fabricate a Type B sleeve.

C.4.3 Pumpkin Sleeves

In many older pipelines, joints were made by mechanical compression type couplings. These couplings usually included longitudinal bolts and collars used to compress packing or gaskets to seal against the pipe. They provided negligible longitudinal stress transfer along the pipeline, so they were subject to “pull-out” incidents when unusual longitudinal loads were imposed upon the pipeline. To overcome the pullout problem and leakage problem, a “pumpkin” sleeve may be installed over the coupling and fillet welded to the pipe on both ends. The side seams are also welded so the sleeve can contain pressure. Pumpkin sleeves may also be used to repair buckles, ovalities, and wrinkle bends because they can fit over such anomalies. This type of pumpkin sleeve should be installed in the same manner as a conventional Type B sleeve. Because pumpkins typically have a diameter significantly larger than the carrier pipe, they need to be thicker or of higher grade than the carrier pipe to carry the design pressure; therefore, a thorough technical design check should be carried out prior to the installation of a pumpkin.

Another type of pumpkin may be installed over a leaking tap after the leak has been stopped. A small piece of pipe (pup) with a cap welded to the end is welded to the pipe to prevent any possible leaking from the tap. The pumpkin has typically been used only as a last resort technique when a Type A or Type B steel reinforcement sleeve proves to be inadequate. Used in this manner, they typically are considered temporary.

C.4.4 Over Sleeves

An over sleeve is a sleeve specifically designed to fit the outer diameter of the type A or type B sleeve, and can be used to bridge two adjacent sleeves, extending the length of the repair.

C.5 Split Sleeve Reinforcement Clamps (or Bolt-on Clamps)

Split sleeve reinforcement clamps are a widely used method to repair anomalies to restore full pipeline MOP and may be considered a permanent repair in most situations. They can be used on both high and low pressure pipelines carrying oil, gas, or products. Typically, bolt-on clamps are quite thick and heavy due to the large bolts needed to ensure adequate clamping force. Although there are many types of commercially available bolt-on clamps, there are two basic installation configurations:

1) elastomeric sealing only,

2) elastomeric sealing with welding.

The elastomeric seal is designed to contain the pressure if the defect is leaking. The welding option is designed as a backup device. If the elastomeric seal should fail, the welded clamp is designed to seal the leak and continue to contain the pressure. The welded-up option should be chosen on an individual case basis, but care should be taken
when welding bolt-on clamps, especially due to wall thickness mismatch. In addition, packing materials should not be overheated, yet fusion to the heavy wall must be obtained. Split sleeve reinforcement clamps consist of the following:

a) Advantages:
   - Clamps are sometimes cost effective.
   - No welding to the carrier pipe is required.
   - Clamps can be used to repair leaking defects.

b) Disadvantages:
   - The short length prevents use on larger anomalies although custom sleeves can be fabricated in longer lengths.
   - Typically used on straight sections of pipe but custom applications for elbows and fittings are available.

C.6 Composite Reinforcement Sleeve

Composite reinforcement sleeves are used to reinforce a defect-weakened area of pipe as an alternative to a Type A split steel sleeve for non-leaking defects. They are designed to repair blunt corrosion defects and are available in a variety of technologies. An operator should investigate each technology to ensure that reliable engineering tests and analysis show the repair can permanently restore the serviceability of the pipe.

Installers should be trained on the specific composite sleeve being installed if the manufacturer is not performing the work. Certain composite sleeve manufacturers require their approval of the installation design prior to installation, even with training.

a) Advantages:
   - No welding is involved.
   - The material does not corrode.
   - Sleeves can repair bends and long radius elbows.

b) Disadvantages:
   - The installed sleeve has less reinforcing ability than a steel sleeve of comparable thickness. This limits its use to repair of blunt defects and dents.
   - As with a Type A steel sleeve, the composite sleeve cannot be used to repair a leaking defect or one that may develop a leak.
   - The repair cannot be seen by an ILI tool without the installation of a marker, such as a steel band.
   - There is limited data available on the performance of non-destructive methods to determine if the wrap has been properly installed and is properly supporting the anomaly.
C.7 Other Repairs

C.7.1 Other types of pipeline repairs include:

— Weld Deposit Repairs—Repairing a pipeline by means of deposited weld metal involves replacing lost or damaged metal with a filler metal to restore the continuity of the pipe. This type of repair requires special procedures.

— Hot Tapping—Some defects, leaking or non-leaking, may be removed on an in-service pipeline by hot tapping a fitting over the defect and cutting out the defect. This type of repair also requires special procedures.

— Leak Clamps—Temporary, low-stress repairs lasting only until the pipe segment can be replaced. Leak clamps are distinguished from pipe clamps or sleeves due to their temporary nature and their inability to carry significant hoop stress.

— Incompressible Resin-filled Sleeve—This system uses a metallic shell filled with epoxy grout. The technique is considered to be a permanent repair for gouges, corrosion, dents, circumferential, or girth-weld defects, without any welding on the carrier pipe.

— Grinding Repairs—Grinding by hand filing or power disk grinding is widely accepted for repairing superficial defects and some more significant defects such as gouges.

— Incompressible Resin-filled Sleeve—This system uses a metallic shell filled with epoxy grout. The technique is considered to be a permanent repair for gouges, corrosion, dents, circumferential, or girth-weld defects, without any welding on the carrier pipe.

— Grinding Repairs—Grinding by hand filing or power disk grinding is widely accepted for repairing superficial defects and some more significant defects such as gouges.

UTT readings should be made at the location of the grind to determine wall thickness remaining pre- and post-grind. PAUT or other NDE needs to be used to evaluate the defect that is to be removed to determine depth and then if grinding operations can proceed. Great care should be taken when grinding in seams, particularly vintage seams. The area in question also needs to be able to pass ASME B31G calculations for strength remaining at that location (L-tables, Effective Area Method).

— Other Composite Repairs—Other wet layup wraps can be used to repair elbows, tees, or other fittings. When using this repair, operators should verify compatibility of wet layup material with the product being transported.
Annex D
(normative)

Calculating Reassessment Intervals

D.1 Reassessment Intervals for Linear Growth Rates

D.1.1 Reassessment Interval Based on a Failure Pressure versus Flaw Size Relationship

The principle involved in calculating reassessment intervals for flaws with linear growth rates is illustrated in Figure D.1.

Figure D.1—Reassessment Intervals Based on a Specific Failure-pressure vs Flaw-size Model

Figure D.1 is based on a specific failure-pressure-versus-flaw-size model, but generically, the procedure would be similar for any validated model. In this example, it is assumed that an initial integrity assessment has established a minimum failure pressure corresponding to 100 % of SMYS for the worst case (i.e., lowest-failure pressure flaw) that could possibly remain in the pipeline segment. This level can be established either by completing a hydrostatic test of the segment to a minimum hoop stress level of 100 % of SMYS or by remediating all anomalies that were shown by ILI to be of a size that would cause failure at a hoop stress level less than 100 % of SMYS. For the 12.75 in. OD, 0.156 in. wall, X42 pipe (SMYS = 42,000 psi) considered in this example, the 100 % of SMYS level cuts across the specific maximum depth-to-thickness curves at specific lengths (e.g. a length of 2 in. for a d/t ratio of 0.5, a length of 6 in. for a d/t ratio of 0.3, etc.). Growth of a flaw in depth has a much greater deleterious effect on failure pressure than growth in length, whereas growth in length can be safely ignored. Therefore, each length of a flaw is considered for its growth through the wall thickness (i.e. an increase in d/t with the passage of time).

A pipeline operator should plan to remediate a potentially growing flaw or prevent it from failing in service by performing a reassessment of the integrity of the segment by the time the flaw has grown to a depth that will cause a failure at 1.1 times the MOP of the segment. When planning the reassessment, the amount of time it could take to excavate an area should be considered such that the flaw can be remediated before a timeline is exceeded. If the MOP of the segment corresponds to 72 % of SMYS, the limiting d/t ratio for each anomaly corresponds to the point
where the vertical arrow for each length of a flaw intersects the horizontal line at $1.1 \times 72 \%$ of SMYS. The level of hydrostatic test that is performed should be evaluated by the operator on a case-by-case basis; not all pipelines need to be tested to a minimum hoop stress of 100 % SMYS (see API RP 1179 for guidance).

According to Figure D.1, a 2 in. long flaw could survive a test to 100 % of SMYS if it has a d/t not exceeding 0.5. If the flaw grows to a d/t of 0.72, it will fail at a pressure level of $1.1 \times 72 \%$ of SMYS. Similarly, a 5 in. long flaw could survive a test to 100 % of SMYS if it has a d/t not exceeding 0.31, but it will fail at a pressure level of $1.1 \times 72 \%$ of SMYS if it grows to a d/t of 0.53. The change in d/t required for the decay from 100 % to $1.1 \times 72 \%$ varies over a narrow range irrespective of the length of the flaw, so the assumption that length is not important when it comes to calculating a retest interval is a good one. However, the operator should focus on the lowest amount of growth required, in this case, a change of 20 % of the wall thickness. Note that decay to a lower pressure level requires more growth of a flaw, and that means that lowering the operating pressure is one option for prolonging the time between assessments.

Armed with information that a change in d/t ratio of 0.2 will lower the failure pressures of the worst-case flaws in the example pipe material by a critical amount that should not be exceeded, the pipeline operator then calculates the maximum time allowed before remediation of the flaw dividing the corresponding wall thickness change by the rate of flaw growth for any mechanism expected to have a constant growth rate (i.e. corrosion or SCC, but not fatigue). For the 0.156 in. wall pipe of the example, 20 % of the wall thickness is 0.031 in. or 31 mils. If the flaw growth rate does not exceed 3.1 mils/year, the operator would have 10 years to either remediate the worst-case flaw (and others as their $1.1 \times 72 \%$ of SMYS failure pressure level is approached) or conduct a reassessment of the integrity of the segment.

### D.1.2 Reassessment Intervals Based on Material Toughness

In one respect, calculating a reassessment interval for a segment affected by external or internal corrosion-caused metal loss is similar to calculating a reassessment interval for a segment affected by SCC. Both phenomena can be assumed to have constant growth rates (SCC rates in liquid pipelines can vary over time but an average, linear growth rate can be applied). The major difference between calculating reassessment intervals for corrosion-caused anomalies and calculating reassessment intervals for SCC arises because the corrosion-caused anomalies are blunt anomalies and SCC anomalies are comprised of sharp cracks. Failures of blunt defects tend to be controlled solely by the size of the defect and the strength of the material. In contrast, failures of sharp cracks tend to be controlled by the size of the defect, the strength of the material, and the toughness of the material (i.e. its resistance to tearing in the presence of a sharp crack). Sharp cracks in materials of less-than-optimum toughness tend to fail at stress levels below that at which the same-size blunt defect would fail. The significance of this difference in behavior can be seen by comparing Figure D.2 and Figure D.3.

Figure D.2 gives failure-pressure-versus-flaw-size relationships for flaws in a 20 in. OD, 0.250 in. wall, X52 (SMYS = 52,000 psi) material. The toughness of the material is characterized by a Charpy V-notch upper shelf energy of 500 ft-lb. This level is fictitious since it exceeds the maximum level that is technologically possible. A material with this level of energy is so tough that all defects fail when the stress level in their remaining ligaments reach the flow stress of the material. This is also how blunt flaws behave. Therefore, Figure D.2 can be used to represent corrosion-caused metal loss flaws.

Figure D.2 is the basis for the example used in Section 10 with Figure 6. In that example a 14 in. long flaw was considered. The upper end of the vertical arrow in Figure D.2 represents the maximum depth-to-thickness ratio that would allow the 14 in. long flaw to survive the integrity assessment hydrostatic test to 100 % of SMYS, namely, $d/t = 0.20$. Since the nominal wall thickness is 0.250 in., $d_{initial}$ is 0.050 in. The lower end of the arrow (representing growth to the depth that causes the failure pressure of the flaw to decline to $1.1 \times 72 \%$ of SMYS) is located at a depth-to-thickness ratio of 0.40. The $d_{final}$ is 0.100 in. Thus growth of 0.050 in. (50 mils) lowers that failure pressure of the flaw from an initial value of 100 % of SMYS to a final value of $1.1 \times 72 \%$ of SMYS.

Figure D.3 also gives failure-pressure-versus-flaw-size relationships for flaws in a 20 in. OD, 0.250 in. wall thickness, X52 (SMYS = 52,000 psi) material, but the toughness in this case is less than optimum. The toughness of the material is characterized by a Charpy V-notch upper shelf energy of 25 ft-lb. A material with this level of energy is typical of
older vintage (pre-1970) line pipe materials. It may be expected that sharp defects will fail at a stress level in their remaining ligament that is somewhat less than the flow stress of the material. For example, the 14 in.-long flaws that survived the 100% of SMYS test with optimum toughness as shown in Figure D.2 had a depth-to-thickness ratio of 0.20. As shown in Figure D.3, the 14 in.-long flaw would have a depth-to-thickness ratio of 0.14 if the toughness corresponds to 25 ft-lb of Charpy energy. Figure D.3 can be used to represent SCC in the base metal of a line pipe material, but the actual Charpy energy of the material being considered should be used to generate the curves.

Using these two figures, an individual can compare the amount of growth in depth required for the failure pressure of a 14 in.-long flaw to decay from 1300 psig (100% of SMYS) to 1030 psig (1.1 × 72% of SMYS). For the blunt flaw or optimum toughness case (Figure D.2) the depth of the flaw changes from 20% of the wall thickness to 40% of the wall thickness. This corresponds to a change of depth of 50 mils. For the SCC in a material with a Charpy shelf
energy of 25 ft-lb the depth changes from 14 % of the wall thickness to 31 % of the wall thickness. This also corresponds to a change in depth of 42.5 mils. Note that the depth of the flaw in the latter case is less at each benchmark pressure level than in the case of the blunt flaw. In both cases the times to reassessment are calculated by dividing the changes in depth by the rate of growth. If the blunt corrosion flaw grows at a rate of 10 mils per year, reassessment will be required in 5 years. If the SCC grows at a rate of 10 mils per year, reassessment will be required in 4.25 years.

The model used to generate Figure D.1 through Figure D.3 is valid for use with materials that exhibit a minimum Charpy upper shelf energy of 15 ft-lb. It cannot be used to address flaws in the bondline of LF-ERW pipe where the level of Charpy energy is likely to be much less than 15 ft-lb. A similar procedure can be carried out for predicting reassessment intervals for bondline flaws in such materials. One way of doing this is to use the failure assessment diagram (FAD) approach outlined in API Standard 579-1/ASME FFS-1, *Fitness-For-Service*. For the 20 in. OD, 0.250 in. wall thickness, X52 (SMYS = 52,000 psi) pipe discussed, a FAD calculation based on an assumed Charpy energy of 4 ft-lb results in predictions that a 14 in.-long crack in such a material could only survive a hydrostatic test to 1300 psig if the flaw was no deeper than 11 mils and that at the 1.1 \times 72 \% of SMYS pressure of 1030 psig, the crack could be no deeper than 31 mils. Therefore, with a margin for growth of only 20 mils, a reassessment would be needed in two years if the growth rate of the flaw was 10 mils per year.

**D.2 Reassessment Intervals for Non-linear Growth Rates**

**D.2.1 Reassessment Intervals for Crack-like Flaws**

Remaining life calculations using data from either ILI or hydrostatic testing combined with applicable growth models are used to determine reassessment intervals for crack-like flaws. An appropriate factor of safety should be applied to remaining life calculations, and the result added to the date of the previous assessment. The factor of safety should consider the level(s) of conservatism applied to the remaining life calculation and also should take into account the risk associated with the pipeline. Consideration should also be given to the overall timeframe because short calculated times to failure can be overly sensitive to input assumptions.

Aside from regulatory requirements, the reassessment needs to occur before any potential cracks reach a critical size, taking into account the uncertainties associated with tool technology and inputs to the remaining life calculations. The assessment method chosen needs to be able to detect or eliminate the size of cracks that have set the reassessment interval.

**D.2.2 Benchmark Cycles for Assessing Fatigue Crack Growth**

For a pipeline operator to determine whether a particular segment needs a seam integrity assessment from the standpoint of flaws that may be growing as the result of pressure-cycle-induced fatigue, the following procedure may be used. The objective is to compare the actual cycles experienced by the segment to a set of benchmark cycles that have been developed based on actual pipeline experience that indicate the degree of aggressiveness of the cycles in terms of the likelihood that fatigue crack growth will occur. The benchmark cycles, which were developed from pipelines of CX52 pipe, are shown in Table D.1.

The actual cycles experienced for a representative year should be obtained from the operating data for the segment. A sampling rate of two minutes or less is recommended to capture all pressure fluctuations of 25 psig or more. Cycles are counted by paring maximums and minimums in a systematic way. Although a number of schemes for counting cycles exist, rain-flow counting has been found to be one of the most conservative and therefore it is appropriate for fatigue crack growth in pipelines (see ASTM E1049-85, *Standard Practices for Cycle Counting in Fatigue Analysis*).

Once the pressure cycles are counted they can be compared to the benchmark cycles in Table D.1. In most cases they have to be adjusted to make a legitimate comparison. Adjustments to convert the actual cycles to benchmark-equivalent cycles can be done by means of techniques such as Miner’s rule using an applied-stress versus cycles-to-failure relationship such as the one given for carbon steel in the ASME *BPVC*, Section VIII, Division 2, Appendix 5 (Figure 5-110.1). The ASME “fatigue” curve applies to specimens containing no anomaly. Therefore, comparing time
to failure using a fatigue crack growth model would be expected to produce times to failure for the actual cycles for
any surviving anomalies. This would provide a more reliable assessment of cycle severity, and it establishes for the
user the worst-case anomalies that remain after the last integrity assessment.

**Table D.1—Benchmark Cycles to Determine Cycle Aggressiveness**

<table>
<thead>
<tr>
<th>Cycle Size, % SMYS (X52 Pipe)</th>
<th>Cycle Size, psi (X52 Pipe)</th>
<th>Very Aggressive</th>
<th>Aggressive</th>
<th>Moderate</th>
<th>Light</th>
</tr>
</thead>
<tbody>
<tr>
<td>Over 65 to 72</td>
<td>33,801 to 37,440</td>
<td>20</td>
<td>4</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Over 55 to 65</td>
<td>28,601 to 33,800</td>
<td>40</td>
<td>82</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Over 45 to 55</td>
<td>23,401 to 28,600</td>
<td>100</td>
<td>25</td>
<td>10</td>
<td>0</td>
</tr>
<tr>
<td>Over 35 to 45</td>
<td>18,201 to 23,400</td>
<td>500</td>
<td>125</td>
<td>50</td>
<td>25</td>
</tr>
<tr>
<td>Over 25 to 35</td>
<td>13,001 to 18,200</td>
<td>1000</td>
<td>250</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>25 or less</td>
<td>13,000 or less</td>
<td>2000</td>
<td>500</td>
<td>200</td>
<td>100</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td><strong>3660</strong></td>
<td><strong>912</strong></td>
<td><strong>363</strong></td>
<td><strong>175</strong></td>
</tr>
</tbody>
</table>

The process of comparing cycle aggressiveness using a fatigue-crack-growth model is illustrated by the
following examples. Consider a pipeline comprised of 20 in. OD, 0.250 in. wall, X52 pipe with a Charpy shelf energy
of 100 ft-lb. Assume that the pipeline experiences one pressure cycle from zero to the MOP of 936 psig (72 % of
SMYS) and back to zero every 16 days and that the last integrity assessment consisted of a hydrostatic test of the
pipeline to a minimum pressure of 1300 psig (100 % of SMYS). It is possible to compare this spectrum with the four
benchmark spectrums using Miner’s rule and the ASME fatigue curve mentioned above, but it is better to use a
fatigue crack growth model if one is available. Using a typical fatigue crack growth model and the default C and n
values, one can show that the shortest calculated time to failure arises from an anomaly that is initially 80 % through
the wall and 1.16 in. long. The calculated time is 16.6 years, so applying a factor of safety of two, the pipeline operator
might decide to reassess the pipeline in 8.8 years anyway even if the cycles do not turn out to be aggressive or very
aggressive. One reason that the operator might not reassess the pipeline in that amount of time could be that there is
sound evidence that no 80 % through-the-wall anomaly exists. The same analysis shows, for example, that a 40 %
through-the-wall anomaly has a remaining life of 30.2 years. Another reason could be that the default crack growth
rate is too conservative for the particular environment of the pipeline segment.

To evaluate the degree of cycle aggressiveness one has to run the fatigue-crack-growth model for the same pipeline
four times using the very aggressive, aggressive, moderate, and light cycles of Table D.1. The same C and n values
should be used throughout that were used for the calculation using the actual operating spectrum. The model shows
that the minimum remaining lives in these cases are also associated with an 80 % through, 1.16 in. long anomaly. The
times to failure are:

— 0.9 year for very aggressive cycles,
— 3.7 years for aggressive cycles,
— 9.6 years for moderate cycles,
— 23.3 years for light cycles.

Thus, the operator can conclude that one cycle from zero to the MOP and back to zero every 16 days constitutes light
to moderate cycle aggressiveness. This does not mean that the pipeline would never experience a fatigue failure, but
experience has shown that pipelines that do exhibit fatigue failures tend to have aggressive to very aggressive cycles.
Some additional points about cycle severity worth noting are as follows.

— If the cyclic spectrum changed from one full-MOP cycle every 16 days to one full-MOP cycle every four days, the minimum calculated time to failure would change by a factor of 4 to 4.4 years. This would put the pipeline in the aggressive category.

— If the pipeline experiences one full-MOP cycle every 16 days, but it was tested to only 90 % of SMYS instead of 100 % of SMYS the minimum calculated time to failure is 3.9 years. Thus the pipeline would be placed in the aggressive category. This illustrates why it is good to test a pipeline to as high a pressure as possible, or if ILI is the means of assessment, anomalies having predicted failure pressures below 100 % of SMYS should be remediated.

— If the pipeline was comprised of a pipe material of the same geometry and Charpy energy, was tested to 100 % of SMYS, is operated at 72 % of SMYS, and is operated with one full-MOP cycle every 16 days, but is comprised of X60 pipe instead of X52, the minimum calculated time to failure is 13.2 years (compared to 16.6 years for X52). The 100 % of SMYS pressure for X60 is 1500 psig and the 72 % of SMYS pressure is 1080 psig. Therefore, a full-MOP cycle is zero to 1080 psig (43,200 psi hoop stress) and back to zero for the X60 pipeline in contrast to the full-MOP cycle for X52 (37,440-psig hoop stress). The larger stress cycle produces a shorter fatigue life even though both pipelines were subjected to the same test-pressure-to-operating-pressure ratio.
Annex E  
(informative)

Other Technologies

E.1 Direct Assessment

Direct assessment is a four-step process:

1) Pre-assessment is carried out for a segment based on the attributes of the segment and its operating history.

2) Indirect measurements are made to detect possible locations where anomalies may exist.

3) Direct examinations (excavations and examinations of the pipeline) at selected locations (based on the indirect measurements) are made to assess the nature of anomalies, if any.

4) Post-examination is carried out to evaluate remaining life and to evaluate the direct assessment process itself.

In the case of ECDA, the pre-assessment identifies whether ECDA is feasible for a given segment. ECDA cannot be used for underwater pipelines. The electrical measurements typically used for ECDA do not work inside casings; GWUT can be used as an indirect inspection method for pipes inside steel casings as part of the ECDA. Other factors such as extremely poor coating or excessively deep burial may defeat the use of ECDA. The indirect assessment entails utilizing at least two types of above-ground electrical measurements such as close-interval pipe-to-soil potential surveys, DC voltage gradient surveys, or current attenuation surveys to locate coating faults and cathodic protection current anomalies that may indicate that external corrosion has occurred, may be occurring, or could occur in the future.

Since mechanical damage inherently is associated with coating damage, it is likely that locations of mechanical damage will be identified by the electrical surveys. Locations for direct examinations are selected based on the findings of the electrical surveys, and usually, some random locations not indicated by the surveys are examined as well to check the validity of the surveys. Repairs are made to any coating anomalies, the anomalies are assessed in terms of their effect on remaining strength and repaired if necessary, and data are gathered on coating condition and soil properties that could affect corrosion. Repairs are made to any pipe defects which would impair pipeline integrity based on criteria such as B31G, Modified B31G, or RSTRENG. The post-examination step involves calculating remaining life, setting reassessment intervals, and determining whether ECDA has been shown to work for the segment. A pipeline operator who elects to use ECDA for integrity assessment should carry out the assessment in accord with NACE SP0502-2002.

In the case of ICDA, the pre-assessment involves examining pipeline attributes and historical data; gathering terrain (elevation profile) and flow rate data; and consideration of factors such as product type, water content, inhibitor or biocide programs, and cleaning pig frequency to be able to identify locations where internal corrosion might be expected to occur. Note that the flow rate should be great enough to entrain water and solids into the fluid stream; the presence of turbulent flow alone does not necessarily guarantee sufficient velocity. The use of ICDA is not recommended if these data cannot be acquired, if the likely rate of corrosion cannot be inferred, if a continuous water phase is present, or if direct examination of the likely locations of corrosion is not feasible. Indirect examination involves identifying the likely locations for internal corrosion to have occurred. This is done by considering where liquid water and/or solid waste or sediment could accumulate as the result of elevation profile and flow rate. Models are available for determining such locations. Locations for direct examinations are selected based on the findings of the evaluations of likely locations for internal corrosion to have occurred, and usually, some random locations not indicated by the evaluations are examined as well to check the validity of the evaluations.

Nondestructive thickness measurements are made at the selected locations to determine whether wall thickness degradation has taken place. Repairs are made to any pipe defects which would impair pipeline integrity based on
criteria such as B31G, Modified B31G, or RSTRENG. The post-examination step involves estimating remaining life, setting reassessment intervals, and determining whether ICDA has been shown to work for the segment. A pipeline operator who elects to use ICDA for integrity assessment should carry out the assessment in accordance with NACE SP0208.

In the case of stress corrosion cracking direct assessment (SCCDA), the pre-assessment involves reviewing historical data for a given segment that would suggest whether the segment might be susceptible to SCC. The factors that control susceptibility to "high-pH" SCC for a liquid pipeline are operating stress level (60 % of SMYS is threshold above which susceptibility is assumed likely), an operating temperature above 100 °F, the years the system has operated in the susceptible range, and the coating type is other than fusion-bonded epoxy. The factors that control susceptibility to "near-neutral-pH" SCC are the same except that susceptibility may exist irrespective of the operating temperature. When determining the susceptibility of a pipeline segment for near-neutral-pH SCC, it is important to consider the presence of dents with high residual strain as potentially susceptible sites. The indirect assessment entails acquiring data such as pipe-to-soil potential measurements from close-interval surveys and DC voltage gradient surveys to indicate where coating disbondment may have occurred and information on terrain, soil type and drainage as these factors are known to influence susceptibility. Locations for direct examinations are selected based on the findings of the electrical, soil type, terrain, and drainage surveys.

Soil models exist that may assist the operator in identifying locations of likely susceptibility. Usually, some random locations not indicated by the surveys are examined as well to check the validity of the surveys and any soil model that may be employed. The direct examinations involve examining the coating, terrain, soil, and drainage conditions and examining the pipe surface by means of magnetic particle inspection to ascertain whether SCC exists and, if so, which type of cracking (high-pH or near-neutral-pH) is taking place. Repairs are made to any pipe defects which would impair pipeline integrity based on an engineering fracture mechanics assessment criterion. The post-examination step involves setting reassessment intervals, and determining whether the SCCDA survey and analysis process have been shown to work for the segment. A pipeline operator who elects to use SCCDA for integrity assessment should carry out the assessment in accord with NACE SP0204.

GWUT involves inducting ultrasound waves into a pipe segment through a concentric collar (the pipe does not have to be out of service). Waves propagate axially using the pipe wall thickness as a wave guide. Wall thickness anomalies cause reflections that are interpretable in terms of thickness loss. The distance capability for this to work is limited. It is on the order of 100 ft to 200 ft, depending on energy absorption characteristics of the pipe-coating-soil interface, so it is not practical to inspect long segments of pipe by this method. The technique has proven useful for short segments where neither access to the pipe nor pigging is feasible. Examples are pipe inside a casing, risers at platforms, and short delivery lines. The technique can locate areas of metal loss caused by either external or internal corrosion.

E.2 Visual Inspection

Visual inspection of an aboveground pipeline is useful for identifying areas of external corrosion or mechanical damage. Visual inspection of pipe exposed by excavation is useful for identifying areas of sagging or missing coating. All anomalies identified at an excavation site should be visually inspected and photographed in addition to whatever physical measurement or nondestructive inspections are used.
Annex F
(informative)

Leak Detection Methods

F.1 Introduction

The well-known leak detection systems are as follows.

— Periodic Auditory, Visual, and Olfactory Inspections—Operators use a variety of periodic inspections to detect leaks. These may include aerial patrols, surface patrols, station walk-throughs, etc., and personnel looking for dead vegetation, stained areas, pooled or free-flowing product, vapor or vapor clouds, ground frost, hissing sounds, or odors, or a combination thereof.

— Volume Balance—One of the oldest techniques involves comparing the mass of fluid put into the pipeline with the mass of fluid coming out at the other end. The comparison should be made over a period of time such as one hour or longer to eliminate the effects of transients (i.e., its application is based on the assumption that the flow is steady state). The method does not locate the leak. Errors in measurement, metering, or temperature can limit success.

— Dynamic Flow Modeling—Dynamic flow modeling involves simulating the operating conditions of the pipeline through hydraulic calculations based on flow rate, temperature, pipeline profile, and fluid properties. The calculated conditions are then compared to real time data acquired from various measurement points along the pipeline. Deviations are evaluated against alarm set points. The alarm set points should be selected to find the smallest leak that is distinguishable from background noise so as to minimize false alarms. The size of leak that can be found will be a certain percentage of the volume of fluid in the system. The software models for this purpose are normally integrated into the SCADA system of the pipeline. Leak location information is not provided automatically, but analysis of transients can be used to locate a leak. A pipeline operator may find it useful to consult API 1149 and API 1130 in conjunction with employing a dynamic flow model leak detection system.

— Tracer Chemical—This approach to leak detection requires mixing a small amount of a specific volatile chemical tracer with the contents of a pipeline. The chemical tracer is not a component of the pipeline contents and does not occur naturally in soil. After the chemical is injected into the pipeline, soil vapor samples are obtained from probes or other devices installed intermittently along the pipeline. The vapor samples are analyzed by a gas chromatograph for the specific tracer chemical. Presence of the chemical in the sample can only occur through leakage from the pipeline. This method can be used periodically or continuously to examine for leakage. Since the locations of the samples are known, it is possible to locate the leak within the limits of distances between sample points. One limitation of this method is that you need to restart a line with a suspected leak in order for tracer chemicals to work.

— Release Detection Cable—Leak-detection-sensing cables can be installed in the pipeline trench over, under, or along-side the pipeline. Typically, the cable is installed within a continuous perforated plastic tube. The presence of a hydrocarbon creates a circuit between two sensing wires within the cable, sending a signal of the leak and the location to the pipeline control center. This kind of system most likely can only be installed as the pipeline is being constructed. It would seem that retrofitting an existing pipeline would be prohibitively expensive. One limitation of detection cables is that they can be defeated by previously existing contamination.
Shut-in Leak Detection—Shut-in leak detection, also known as a “stand-up test” consists of shutting off flow in a pipeline and closing the valves to hold the pressure constant. The pressure will remain constant except for changes due to temperature variations unless a leak exists. The rate of pressure decay in the event of a leak is indicative of the size of the leak. It should be noted that leakage through valves, if it occurs, will confound the ability to judge whether a leak exists. No information on the location of the leak is provided by this type of test.

Pressure Point Analysis Leak Detection Software—This software examines pressure data acquired at high sampling rates from discreet locations and it calculates mass balance in real time. Pattern recognition algorithms are used to distinguish leak events from normal operations. Since the locations of the pressure point samples are known, it is possible to locate the leak within the limits of distances between sample points.

Acoustic Leak Detection—Acoustic leak detection technologies use listening devices, such as microphones, hydrophones and accelerometers, to detect sound emitted from a pipeline leak. The sound level and tone from a leak depends on the orifice size, the pipe diameter, the pipeline pressure, product type, and the soil conditions (soil type, compaction, and depth of cover) surrounding the pipeline. For leaks to be detected, sound levels from leaks need to exceed the natural sound level in the pipeline caused by the pumps, operations, and the flowing product. The sound from a leak dissipates and is dispersed below this natural background noise level over distances that make distributing listening devices along a pipeline rarely practical. Newer technologies deploy listening devices internally propelled by the product, similar to ILI tools. The advantage of the in-line listening tools is the proximity of the listening device to the leak which enables detection of leaks significantly smaller than those found using conventional dynamic flow modeling systems. As for limitations, these internal devices can interfere with pipeline operations and throughput due to launching and receiving operations and flow restrictions. A potential effective use of this technology is to ensure that no additional leaks exist on a pipeline that has experienced a small leak that was not detected by the more conventional leak detection methods.
Annex G
(informative)

Facilities Piping and Equipment Threats

G.1 Introduction

Facility threats are discussed in this section. Threats from equipment failure and incorrect operations should be addressed through operating procedures, equipment maintenance and inspection, operator qualification, and quality control processes. Inspection and maintenance of pipeline breakout storage tanks are covered by API 653.

Annex G is organized as shown in Table G.1.

<table>
<thead>
<tr>
<th>Main Topic</th>
<th>Subtopic</th>
<th>Subject Matter</th>
</tr>
</thead>
<tbody>
<tr>
<td>G.2 External Corrosion</td>
<td>Soil-to-Air Interface</td>
<td>Visual inspection, removing soil and coating if necessary, carefully replacing coating and seals.</td>
</tr>
<tr>
<td></td>
<td>Contact Corrosion</td>
<td>Visual inspection possibly supplemented by UT or GWUT, use of dielectric materials to separate pipe from support structures or hangers.</td>
</tr>
<tr>
<td></td>
<td>Corrosion Under Insulation</td>
<td>Preventing water ingress, checking for missing or damaged insulation, using “plugs” for inspection sites.</td>
</tr>
<tr>
<td>G.3 Internal Corrosion</td>
<td>Dead legs, Drain Lines, and Relief Valves</td>
<td>Periodic flushing to remove water and sludge, periodic UT measurements of wall thickness, GWUT for inspection of buried segments, remove unnecessary dead legs.</td>
</tr>
<tr>
<td>G.4 Erosion and Corrosion/Erosion</td>
<td></td>
<td>Inspecting wall thickness at locations of high flow and/or direction changes.</td>
</tr>
<tr>
<td>G.5 Environmental Cracking—Ethanol Related Cracking</td>
<td></td>
<td>Inspection for systems that have demonstrated susceptibility, reference documents for detailed prevention and mitigation.</td>
</tr>
<tr>
<td>G.6 Manufacturing Defects</td>
<td></td>
<td>Quality assurance and control programs during procurement activities to prevent manufacturing defects from entering service.</td>
</tr>
<tr>
<td>G.7 Construction and Fabrication Defects</td>
<td></td>
<td>Quality assurance and control programs during construction activities to prevent construction defects from entering service.</td>
</tr>
<tr>
<td>G.8 Equipment Failures—Tubing and Small Bore Piping</td>
<td></td>
<td>Importance of proper installation, mitigation of vibration and stress, use of electrical instrumentation in place of small tubing.</td>
</tr>
<tr>
<td>G.9 Mechanical Damage</td>
<td></td>
<td>Susceptibility of facilities to mechanical damage from vehicles and construction equipment from increased activity as well as vandals.</td>
</tr>
<tr>
<td>G.10 Incorrect Operations</td>
<td></td>
<td>Taking precautions to minimize human error incidents for tubing and small bore piping, valves, and overfill of tanks and sumps.</td>
</tr>
<tr>
<td>G.11 Weather and Outside Force—Freezing of Trapped Water</td>
<td></td>
<td>Inspecting areas where water may become trapped and draining any water before freezing weather occurs.</td>
</tr>
</tbody>
</table>
G.2 External Corrosion

Since facility piping generally cannot be inspected by ILI or subjected to periodic hydrostatic testing, inspections of facility piping and tubing depends on periodic visual inspection and the use of ultrasonic and radiographic wall thickness measurements. For additional information, see API 570 and API 2611. Pipeline operators should perform visual and wall thickness measurements where corrosion rates are known to be higher than average. Each operator should establish periodic inspection programs for the following specific types and areas of deterioration:

— external corrosion at supports and hangers;
— external corrosion at soil-to-air interfaces;
— external CUI.

In all cases, periodic inspections in conjunction with wall thickness measurements are suggested as ways to monitor these situations. The frequency of inspection can be based on a corrosion rate established from the measured wall thickness loss. In the absence of established corrosion rates, other methods may be used to determine corrosion rates (e.g. a Monte Carlo simulation with distributions of pit depths and corrosion starting times). Models for calculating remaining strength of corroded pipe such as Modified B31G or RSTRENG can be used to predict SOPs or corroded tubing and piping within facilities. Operators should be cautious about using these models alone with piping that is operated at low levels of hoop stress (i.e. less than 50 % of SMYS) because the effect of contact stresses or secondary stresses could cause the failure stress to be less than that predicted by such models. In such cases, the operator should consider carrying out a more sophisticated analysis, for example, by using finite element modeling.

G.2.1 Soil-to-Air Interface

Inspection at grade should include checking for coating damage, bare pipe, and pit depth measurements. If significant corrosion is noted, thickness measurements and excavation may be required to assess whether the corrosion is sufficient to impair the integrity of the piping. Consideration should be given to excavating 12 in. deep to assess the potential for hidden damage. Significantly impaired piping should be repaired or replaced. Thickness readings at soil/air interfaces may expose the metal and accelerate corrosion if coatings and wrappings are not properly restored. If the buried piping has satisfactory cathodic protection, excavation is required only if there is evidence of coating or wrapping damage. At concrete-to-air and asphalt-to-air interfaces for buried piping without cathodic protection, the interface should be inspected for evidence that the caulking or seal at the interface has deteriorated and allowed moisture ingress. If such a condition exists on piping systems over 10 years old, it may be necessary to inspect for corrosion beneath the surface before resealing the joint.

G.2.2 Contact Corrosion

Contact corrosion, particularly more aggressive in humid climates or coastal locations, or both, needs to be monitored. Typical areas for more aggressive corrosion are between the pipe support and contact area of the pipe, and welds/joints along the pipe. Corrosion cells may arise from moisture/dew collection and/or dissimilar metals (i.e. weld material has different composition than the pipe base metal).

Where visual inspection at supports or hangers suggests the presence of corrosion products, the piping and support should be separated to permit detailed inspection with equipment to determine the remaining wall thickness. Whenever possible, the use of NDE, such as UT or GWUT, should be considered in addition to visual inspection. Care should be taken to avoid overstressing the piping by temporarily supporting the pipe adequately if the pipe is to be lifted or the support is to be removed. Piping that has sustained significant wall loss such that either internal pressure or support stresses could cause leakage should be repaired or replaced.

To prevent further corrosion, operators should consider re-coating or installation of dielectric material between the pipe and support. Operators could also design out or minimize the crevice. If no corrosion exists, operators should consider applying epoxy or other sealant material to the pipe support interface.
G.2.3 Corrosion Under Insulation in Aboveground Piping

External inspection of insulated piping systems should include a review of the integrity of the insulation system for conditions that could lead to Corrosion Under Insulation (CUI) and for signs of ongoing CUI. Sources of moisture may include rain, water leaks, condensation, and firewater deluge systems. The most common forms of CUI are localized corrosion of carbon steel.

The extent of a CUI inspection program may vary depending on the local climate. Warmer, marine locations may require an active program, whereas cooler, drier, mid-continent locations may not need as extensive a program.

Certain areas and types of piping systems are potentially more susceptible to CUI, including the following:

- areas exposed to frequent rains;
- areas exposed to steam vents;
- areas exposed to firewater deluge systems;
- areas subject to spills, ingress of moisture, or acid vapors (i.e. from neighboring businesses);
- carbon steel piping systems, including those insulated for personnel protection, operating between 4 °C and 120 °C. CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and re-evaporation of atmospheric moisture;
- attachments that protrude from insulated piping and operate at a different temperature than the operating temperature of the active line;
- vibrating piping systems that have a tendency to inflict damage to insulation jacketing providing a path for water ingress;
- steam traced piping systems that may experience tracing leaks, especially at tubing fittings beneath the insulation;
- piping systems with deteriorated coatings or wrappings, or both.

Piping systems may have specific locations within them that are more susceptible to CUI, including the following.

- All penetrations or breaches in the insulation jacketing systems, such as:
  - dead legs (vents, drains, and other similar items),
  - pipe hangers and other supports,
  - valves and fittings (irregular insulation surfaces),
  - bolted-on pipe shoes,
  - steam tracer tubing penetrations.
- Termination of insulation at flanges and other piping components;
- Damaged or missing insulation jacketing;
— Insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing;

— Termination of insulation in a vertical pipe;

— Caulking that has hardened, has separated, or is missing;

— Bulges or staining of the insulation or jacketing system or missing bands (Bulges may indicate corrosion product buildup);

— Low points in piping systems that have a known breach in the insulation system, including low points in long unsupported piping runs.

Locations where insulation plugs have been removed to permit piping thickness measurements on insulated piping should receive particular attention. These plugs should be promptly replaced and sealed. Several types of removable plugs are commercially available that permit inspection and identification of inspection points for future reference.

G.3 Internal Corrosion

G.3.1 Dead legs, Drain Lines, and Relief Lines

Dead legs are segments of pipe connected at one end to active piping that experiences constant or frequent flow but are closed at one end so that they experience no flow. They may exist for a variety of reasons such as stubs installed for planned future expansions or locations where some type of equipment has been removed. Drain lines are used to drain product from the system when drain-down is required. Relief lines connect pressure relief valves to tanks or flare stacks. The common characteristic of these lines is that the flow of product is either intermittent or nonexistent. As a result, water and or sludge may accumulate in these lines possibly resulting in internal corrosion. The problem is most pronounced with crude oil, but water/condensation is also a cause of internal corrosion in refined product systems. Such systems may be subject to MIC as well. The wall thickness should be monitored periodically at locations where water may be expected to accumulate (i.e. at the stagnant end of a dead leg and at the point of its connection to an active line, and low points and blocked ends to drain lines and relief lines). Wall thickness measures on aboveground piping can be made by an appropriate nondestructive examination method such ultrasonic or radiographic thickness determination. Buried segments may be inspected by GWUT. Where wall thickness losses portend the occurrence of leakage, the particular piping should be repaired or replaced.

Consideration should be given to removing dead legs that serve no further process purpose. Where possible, dead legs, drain lines, and relief lines should be flushed out/displaced on a regular basis. The addition of biocides and corrosion inhibitors to the flushing fluid can slow the rate of deterioration.

G.4 Erosion and Corrosion/Erosion

Erosion can be defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles, or cavitation. It can be characterized by grooves, rounded holes, waves, and valleys in a directional pattern. Erosion is prone to occur in areas of turbulent flow, such as at changes of direction in a piping system or downstream of control valves, where vaporization may take place. Erosion damage is usually increased in streams with large quantities of solid particles and high velocities. A combination of corrosion and erosion (corrosion/erosion) results in significantly greater metal loss than can be expected from corrosion or erosion alone. This type of corrosion occurs at high velocity and high turbulence areas. Examples of places to potentially inspect include:

— downstream of orifices,

— downstream of pump discharges,

— location of at any point of flow direction change, such as the outside radius of elbows.
G.5 Environmental Cracking

Where specific segments or piping circuits have a demonstrated susceptibility to environmental cracking, the operator should schedule supplemental inspections. Such inspections can take the form of NDE, for example, PT or wet fluorescent magnetic-particle testing (WFMT). Where feasible, suspect spools may be removed from the piping system and split open for internal surface examination.

Environmental cracking is not common in pipeline facilities. For consideration of fuel ethanol transport, see API 939-D. Another document for consideration is API 939-E.

G.6 Manufacturing Defects

Manufacturing defects at facilities can include equipment body defects, components not meeting engineering specifications, and seam weld defects. Quality control during procurement, construction, and operations can identify manufacturing defects prior to product entering service. Inspection protocols and procedures can identify equipment and piping manufacturing defects in service. Manufacturing defects discussed in Annex A may also apply at facilities.

G.7 Construction and Fabrication Defects

Construction defects at facilities can include fabrication weld defects, dents or gouges that occur during construction activities, and improper installation of equipment, piping, flanges, and fittings. These threats can be prevented or mitigated through the use of approved procedures, inspection protocols, and robust quality assurance and control programs during construction activities.

G.7.1 Tubing and Small-bore Piping

Noted causes of releases from tubing and small-bore piping include improper installation, vibration and damage by outside force. These problems tend to arise from inadequate design or protection of piping and tubing systems. Piping spans should be supported and protected such that the effects of mechanical vibrations and exposure to outside forces will be minimized. Long unsupported spans of tubing or piping should be avoided. Using tubing or piping to support concentrated loads should be avoided. Tubing and small-bore piping should be protected from vehicles that may be moving around a facility.

G.8 Equipment Failure

Pumps, valve, seals, O-rings, meters, pressure switches, temperature gauges, prover loops, scraper traps, strainers, truck loading racks, etc. are types of equipment found mostly at terminals and pump stations. These components are subject to occasional malfunction and/or failure, and they may in certain cases cause an unintended release. According to the PPTS Advisory 2005-4, valve failures are the second most common cause of releases at facilities (behind pipe failures). The largest cause of valve failures is due to equipment malfunction including gasket or O-ring failure, malfunction of control or relief equipment, seal or packing failures, and stripped threads. Malfunction of control or relief equipment can lead to overfilling of sumps.

G.9 Mechanical Damage

Construction, operation, and maintenance activities are common at pipeline facilities making them susceptible to mechanical damage from vehicular traffic, construction equipment, and other impact mechanisms. Because many facilities are above ground they can be a target for vandals.

G.10 Incorrect Operations

Tubing and small-bore piping (generally considered to be piping of ≤2 in. NPS) have many uses within a facility including instrumentation lines and control lines. Often these lines are assembled with fittings of various types rather that with electric arc girth welding as is the case with mainline pipe. The previously mentioned PPTS advisory found
that improperly installed fittings were one of the most frequent causes of leaks in tubing and small-bore piping. Pipeline operators should establish written standards for the assembly of piping and tubing with fittings. Fitting manufacturers’ assembly instructions should be carefully followed, and individuals employed for the purpose of assembling piping and tubing with fittings should be adequately trained for that purpose.

G.10.1 Overfill of Sumps or Storage Tanks

Storage tanks and more commonly sumps or separators can be overfilled releasing product to the environment. Various errors can lead to overfills including opening or closing of the wrong valve, not monitoring sump fill levels during drain down of pig traps, or misinterpreting alarms.

G.10.2 Valve Misalignment

According to the PPTS Advisory 2005-4, valves left or placed in the wrong position are by far the most prevalent type of error leading to unintentional releases of product or accidental over-pressurization of equipment. Procedures and training of operators during start-up, normal operations, abnormal operation, emergency operations, shut-down, and maintenance activities ensure that valves are appropriately aligned for the specific operational condition.

G.11 Weather and Outside Force Related Defects

At subfreezing temperatures, water and aqueous solutions in piping systems may freeze and cause failure because of the expansion of these materials. After freezing weather, it is important to check for freeze damage to exposed piping components before the system thaws. If rupture has occurred, leakage may be temporarily prevented by the frozen fluid. Low points, drain nipples with valves or caps, and dead legs of piping systems containing water should be carefully examined. If possible, low points and drain lines should be purged of water each year before the start of freezing weather.

Winter weather can also cause extreme contraction and expansion of soft goods (i.e. gaskets and seals) resulting in small volume releases. Proper installation and maintenance is necessary to ensure adequate protection against releases. Refer to manufacturer guidance for specific details.
Annex H
(informative)

Example Visual/Surveillance Inspection Form for Facilities

H.1 Introduction

H.1.1 Figure H.1 shows a sample form to be used by operators performing a facility inspection.

<table>
<thead>
<tr>
<th>Inspection Check List</th>
</tr>
</thead>
<tbody>
<tr>
<td>Customer________________ Date________________</td>
</tr>
<tr>
<td>Location________________ Drawing________________</td>
</tr>
<tr>
<td>Line number/Description__ Material________________</td>
</tr>
</tbody>
</table>

A= Acceptable, FEN= Further Evaluation Needed, NA= Not Applicable, NI= Not Inspected

<table>
<thead>
<tr>
<th>Item Number</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Leaks</td>
</tr>
<tr>
<td>2</td>
<td>Misalignments</td>
</tr>
<tr>
<td>3</td>
<td>Vibration</td>
</tr>
<tr>
<td>4</td>
<td>Supports</td>
</tr>
<tr>
<td>5</td>
<td>Corrosion</td>
</tr>
<tr>
<td>6</td>
<td>Insulation/Coating</td>
</tr>
<tr>
<td>7</td>
<td>Flange and Pipe Information</td>
</tr>
<tr>
<td>8</td>
<td>Piping Start and Stop Locations</td>
</tr>
<tr>
<td>9</td>
<td>Injection or Mixing Locations</td>
</tr>
<tr>
<td>10</td>
<td>Dead Leg Piping</td>
</tr>
<tr>
<td>11</td>
<td>Pressure and Temperature</td>
</tr>
<tr>
<td>12</td>
<td>PSV External Inspection Checklist</td>
</tr>
<tr>
<td></td>
<td>a) Equipment Integrity/Serviceability</td>
</tr>
<tr>
<td></td>
<td>i) Leakage at Flange</td>
</tr>
<tr>
<td></td>
<td>ii) Evidence of mechanical Damage</td>
</tr>
<tr>
<td></td>
<td>iii) Bolting Corroded</td>
</tr>
<tr>
<td></td>
<td>iv) Isolation valves open and car-sealed</td>
</tr>
<tr>
<td></td>
<td>v) Bleeder valves closed and capped</td>
</tr>
<tr>
<td></td>
<td>vi) Service tag attached</td>
</tr>
<tr>
<td></td>
<td>b) Vent piping</td>
</tr>
<tr>
<td></td>
<td>i) Closed system</td>
</tr>
<tr>
<td></td>
<td>ii) Vent piping properly supported</td>
</tr>
<tr>
<td></td>
<td>iii) Weep hole open and clear</td>
</tr>
<tr>
<td></td>
<td>c) Insulation Condition</td>
</tr>
<tr>
<td></td>
<td>i) Blanket or sheathing in place</td>
</tr>
<tr>
<td></td>
<td>ii) Evidence of damage to sheathing</td>
</tr>
<tr>
<td></td>
<td>iii) Bands/wires secure</td>
</tr>
<tr>
<td></td>
<td>iv) Leakage onto insulation</td>
</tr>
<tr>
<td></td>
<td>d) Paint Condition</td>
</tr>
<tr>
<td></td>
<td>i) Fair to Good</td>
</tr>
<tr>
<td></td>
<td>ii) Blisters</td>
</tr>
<tr>
<td></td>
<td>iii) Peeling</td>
</tr>
<tr>
<td></td>
<td>iv) Other</td>
</tr>
<tr>
<td></td>
<td>e) Service tag information</td>
</tr>
</tbody>
</table>

Figure H.1—Example of a Visual/Surveillance Inspection Form for Facilities
Annex I
(informative)

Advisory Bulletins and National Transportation Safety Board (NTSB) Pipeline Accident Report References

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— ADB-2016-04, Ineffective Protection, Detection, and Mitigation of Corrosion Resulting from Insulated Coatings on Buried Pipelines, PHMSA-2016-0071, June 21, 2016

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— ADB-2015-02, Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes, PHMSA-2015-0140, June 23, 2015

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— ADB-2014-03, Construction Notification, PHMSA-2014-0017, September 12, 2014


— ADB-2013-02, Potential for Damage to Pipeline Facilities Caused by Flooding, PHMSA-2013-0136, July 12, 2013


— ADB-2012-10, Using Meaningful Metrics in Conducting Integrity Management Program Evaluations, PHMSA-2012-0279, December 5, 2012

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— ADB-2011-01, Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure Using Record Evidence, and Integrity Management Risk Identification, Assessment, Prevention, and Mitigation, PHMSA-2010-0381, January 10, 2011

— ADB-2011-05, Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes, PHMSA-2011-0183, September 1, 2011
[1] API Recommended Practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe*

[2] API Recommended Practice 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels*

[3] API 570, *Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems*


[5] API Recommended Practice 580, *Risk-Based Inspection*

[6] API Recommended Practice 581, *Risk-Based Inspection Technology*


[9] API Recommended Practice 1109, *Marking Liquid Petroleum Pipeline Facilities*

[10] API Recommended Practice 1110, *Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide*


[12] API Recommended Practice 1133, *Guidelines for Managing Hydrotechnical Hazards for Pipelines located Onshore or within Coastal Zone Areas*

[13] API Publication 1149, *Pipeline Variable Uncertainties and Their Effects on Leak Detectability*

[14] API Publication 1161, *Guidance Document for the Qualification of Liquid Pipeline Personnel*

[15] API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators*

[16] API Standard 1163, *In-line Inspection Systems Qualification*


[18] API Recommended Practice 1165, *Recommended Practice for Pipeline SCADA Displays*

[19] API Recommended Practice 1168, *Pipeline Control Room Management*

[20] API Recommended Practice 1174, *Onshore Hazardous Liquid Pipeline Emergency Preparedness and Response*


[23] API Standard 2610, Design, Construction, Operation, Maintenance and Inspection of Terminal and Tank Facilities

[24] API Recommended Practice 2611, Terminal Piping Inspection-Inspection of In-Service Terminal Piping Systems

[25] API, Pipeline Performance Tracking System (PPTS)

[26] ASME B31.4, Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids

[27] ASME B31Q, Pipeline Personnel Qualification

[28] ASME STP-PT-011, Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas

[29] ASNT ILI-PQ, In-Line Inspection Personnel Qualification and Certification


[31] CGA, Damage Information Reporting Tool (DIRT)

[32] NACE MR0175/ISO 15156, Petroleum and Natural Gas Industries-Materials for Use in H2S-Containing Environments in Oil and Gas Production

[33] NACE RP0177, Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems

[34] NACE SP0102, In-Line Inspection of Pipelines

[35] NACE SP0106, Control of Internal Corrosion in Steel Pipelines and Piping Systems

[36] NACE SP0208, Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines

[37] NACE 35100, In-Line Nondestructive Inspection of Pipelines

[38] NACE 35110, AC Corrosion State-of-the-Art: Corrosion Rate, Mechanism, and Mitigation Requirements

[39] OPS-TTO8, Stress Corrosion Cracking Study

[40] POF 10, Specifications and requirements for intelligent pig inspection of pipelines

[41] PRCI, Pipeline Repair Manual R2260-01R (Catalog L52047)

[42] PRCI, Source for technical reports on pipeline integrity issues available at: https://www.prci.org/1.aspx


Dent Assessment Methodologies

With respect to predicting the effects on the remaining strength of dents or dents containing metal loss, cracks, or gouges, the pipeline operator should seek the assistance of a qualified expert. Alternatively, an operator may find useful guidance in one or more of the following documents.


