Hydrostatic Testing as an Integrity Management Tool

API TECHNICAL REPORT 1179
FIRST EDITION, MAY 2019

AMERICAN PETROLEUM INSTITUTE

Special Notes

American Petroleum Institute (API) publications necessarily address problems of a general nature. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

Neither API nor any of API's employees, subcontractors, consultants, committees, or other assignees make any warranty or representation, either express or implied, with respect to the accuracy, completeness, or usefulness of the information contained herein or assume any liability or responsibility for any use, or the results of such use, of any information or process disclosed in this publication. Neither API nor any of API's employees, subcontractors, consultants, or other assignees represent that use of this publication would not infringe upon privately owned rights.

Classified areas may vary depending on the location, conditions, equipment, and substances involved in any given situation. Users of this standard should consult with the appropriate authorities having jurisdiction.

Users of this standard should not rely exclusively on the information contained in this standard. Sound business, scientific, engineering, and safety judgment should be used in employing the information contained herein. API is not undertaking to meet the duties of employers, service providers, or suppliers to warn and properly train and equip their employees, and others exposed, concerning health and safety risks and precautions, nor undertaking their obligations to comply with authorities having jurisdiction.

Information concerning safety and health risks and proper precautions with respect to particular materials and conditions should be obtained from the employer, the service provider or supplier of that material, or the safety data sheet.

API publications may be used by anyone desiring to do so. Every effort has been made by API to assure the accuracy and reliability of the data contained in them; however, the API makes no representation, warranty, or guarantee in connection with this publication and hereby expressly disclaims any liability or responsibility for loss or damage resulting from its use or for the violation of any authorities having jurisdiction with which this publication may conflict.

API publications are published to facilitate the broad availability of proven and sound engineering and operating practices. These publications are not intended to obviate the need for applying sound engineering judgment regarding when and where these publications should be utilized. The formulation and publication of API publications is not intended in any way to inhibit anyone from using any other practices.

Foreword

Nothing contained in any API publication is to be construed as granting any right, by implication or otherwise, for the manufacture, sale, or use of any method, apparatus, or product covered by letters patent. Neither should anything contained in the publication be construed as insuring anyone against liability for infringement of letters patent.

Shall: As used in a standard, “shall” denotes a minimum requirement to conform to the standard.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required to conform to the standard.

May: As used in a standard, “may” denotes a course of action permissible within the limits of a standard.

Can: As used in a standard, “can” denotes a statement of possibility or capability.

Information marked “NOTE” does not set forth requirements but does provide for guidance in understanding or clarifying the associated requirement.

This standard was produced under API standardization procedures that ensure appropriate notification and participation in the developmental process and is designated as an API standard. Questions concerning the interpretation of the content of this publication or comments and questions concerning the procedures under which this publication was developed should be directed in writing to the Director of Standards, American Petroleum Institute, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001. Requests for permission to reproduce or translate all or any part of the material published herein should also be addressed to the director.

Generally, API standards are reviewed and revised, reaffirmed, or withdrawn at least every five years. A one-time extension of up to two years may be added to this review cycle. Status of the publication can be ascertained from the API Standards Department, telephone (202) 682-8000. A catalog of API publications and materials is published annually by API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001.

This standard should become effective on the date printed on the cover but may be used voluntarily from the date of distribution.

Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001, standards@api.org.

Contents

Contents

Page

Figures

Tables

Introduction

This technical report provides guidance to pipeline operators on the appropriate use of hydrostatic testing within the integrity and risk management process. It considers, as key elements within a hydrostatic test program design process, topics such as known or assumed pipe material properties, threat type and flaw populations, operating and failure history, potential risks and unintended or detrimental effects, and the importance of a clear understanding of test program objectives. This document does not attempt to provide practical guidance for the onsite implementation of a hydrostatic testing program.

This document is primarily focused on pressure test design to achieve objectives, the effect of pressure testing on line pipe steels, and considerations for subsequent pressure testing intervals and reliability. Water, other liquids, air, natural gas, and inert gas are all acceptable test media (as permitted by applicable regulation) for pipeline pressure testing, and identical parameters of physics with respect to the hoop stresses and material properties apply. Due to the relatively high stresses that are generally targeted to achieve integrity testing objectives, water is the preferred test medium for pipelines. For this reason, pressure testing in this document is referred to as "hydrostatic testing." It is acknowledged that when using any form of pneumatic test media (e.g. gases) or liquid product (e.g. refined petroleum products) versus water, vastly different considerations shall be applied for public and personnel safety during testing to account for the potential consequence of a test failure. These are beyond the scope of this work.

This technical report was based upon the extensive hydrostatic testing knowledge that exists today in the form of API recommended practices (RPs), American Society of Mechanical Engineers (ASME) code documents, the body of work of industry consultants, standard practices of operating companies, regulatory language, and other resources. This body of knowledge was supplemented with hydrostatic testing program experience derived from discussion with representatives from a broad group of hazardous liquid and natural gas pipeline operating companies and review of case studies involving several hydrostatic testing programs.

At the time of this guideline development, several parallel pipeline industry initiatives with a focus on hydrostatic testing have been recently completed or are currently ongoing. Such initiatives include work performed by the Pipeline and Hazardous Materials Safety Administration (PHMSA)[1], the American Petroleum Institute (API), the Association of Oil Pipe Lines (AOPL)[2], and the Interstate Natural Gas Association of America (INGAA)[3]. While this completed or ongoing work is of considerable value to the pipeline industry, lacking within these industry initiatives is a focus on the specific application of hydrostatic testing as a pipeline assessment tool to support integrity management plan (IMP) requirements and objectives.

Background

Hydrostatic testing of pipelines has been historically used by the pipeline industry to ensure quality of manufacture and construction, to establish maximum operating pressures, and for management of certain threats to integrity of pipeline systems.

The first version of API 5L for the manufacture of line pipe, issued in 1928, specified requirements for manufacturing specifications, including standard pipe sizes, minimum tensile and chemical content requirements, and required mill pressure tests. In 1942, the voluntary American Standards Association (ASA) Code B31.1 first recommended pressure testing after installation of a pipeline to 1.1 times the maximum operating pressure (MOP), not to exceed 90 % SMYS. In 1959, ASA segmented the code and issued two documents, with one specific to liquids pipelines (B31.4) and the other for gas pipelines (B31.8). These currently exist as ASME B31.4 and B31.8. By the 1960s, most pipeline

1 On October 7, 2009, NTSB issued Recommendation P-09-1 to PHMSA on the safety and performance of ERW pipe. The recommendation called on PHMSA to conduct a comprehensive study to identify actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal seam failures in ERW pipe.

2 The API-AOPL Pipeline Safety Excellence™ 2015 Strategic Plan includes two Strategic Initiatives to develop industry-wide guidance on the appropriate uses of hydrostatic pressure testing of pipelines.

3 Technical, Operational, Practical, and Safety Considerations of Hydrostatic Pressure Testing Existing Pipelines, December 5, 2013.

operators had instituted the practice of hydrostatically testing a newly completed pipeline in the field post-construction.[4] In 1970, Department of Transportation (DOT) federal regulations for pipelines in the U.S. went into effect with 49 CFR §192 and §195 for regulation of gas and liquids pipelines, respectively, requiring the use of hydrostatic testing at construction.

Current uses for hydrostatic testing include original construction testing, integrity assessment of existing pipelines, and pipe material verification when records may be missing or incomplete. Operators should consider the potential for in-service failures of ERW and flash welded pipe that occur after a hydrostatic pressure test is performed in design and implementation of a hydrostatic test program, and guidance on practical consideration of these potential effects is needed.

The benefits, limitations, and appropriateness of pressure testing as an integrity management tool for each recognized threat need to be clarified. Available procedures and references for implementation of a hydrostatic test do not fully account for future operational concerns. The design of a hydrostatic test program can vary based upon the objectives of the test program, specifically the threats considered by the operator for the subject pipe within a test section. For example, managing longitudinal seam integrity versus managing the threat of stress corrosion cracking requires different approaches, as do considerations when testing gas pipeline versus liquid pipeline systems. Many industry references used for guidance in development of hydrostatic test programs do not distinguish these differences sufficiently. It was requested that this effort through PRCI emphasize the differences.

Guidance is also needed to understand the conservatism and variability of current methods for determination of test intervals. Safety factors can be compounded many times through deterministic approaches generally used within the industry. While these may be the simplest from an analytic standpoint, pipeline operators need to develop a thorough understanding of the cumulative effect of applying multiple safety factors when developing hydrostatic pressure testing plans and analyzing data. Safety factors when compounded can sometimes exceed 20, leading to repeat tests at short intervals and potentially exacerbating detrimental effects of testing.

Value

This technical report provides a source of knowledge for pipeline operators, consultants, and contractors tasked with managing or being involved with pipeline hydrostatic testing programs. It is also anticipated that regulatory and industry bodies contemplating the adoption of industry consensus standards and/or regulations pertaining to pipeline hydrostatic testing will view this document as a valuable resource within those development processes.

This technical report provides guidelines to pipeline operators for use in selection and application of hydrostatic testing as an integrity assessment. Specifically discussed are development of test objectives and design considerations when determining the target hydrostatic test pressure(s) to achieve test objectives. Such guidance will aid in achieving the goal of reducing in-service failures, and will assist operators in limiting the number of pressure test failures, providing for increased public safety and reduced environmental impact.

The distinct value that this project brings to the pipeline industry is to supplement the existing standards and body of knowledge in the area of hydrostatic testing with guidelines developed from a pipeline operator perspective and supported by application of hydrostatic testing through the case studies.

Approach

This project began in early 2015 and was managed by Dynamic Risk Assessment Systems, Inc. (Dynamic Risk). The PRCI membership for the IM-3 program at the time the project began consisted of 59 members. A short timeline for completing the project was desired, with a goal to create a guideline document within approximately one year. A smaller core working team was established that consisted of a group of 12 project team members, each of whom committed to have representatives attend monthly face-to-face working meetings through the spring and summer of 2015.

---

[4] Kiefner, J.F. and Trench, C.J. Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction, 2001.

To gather operator experiences and develop practical case studies, in addition to the working meetings among the project team, a series of five meetings were held with pipeline operator representatives from 17 individual operating companies to exchange information and share industry best practices on the design, implementation, data analysis, and evaluation of hydrostatic pressure testing for integrity management. These were held between March 10, 2015 and May 7, 2015. The working team also invited consultants representing five separate pipeline consulting firms to an additional meeting held in conjunction with the PRCI Spring Technical Committees meeting in New Orleans, Louisiana, in May 2015. The purpose of this meeting was to invite these respected researchers to challenge this work and to provide their unique perspectives from their experience in this subject-matter area.

Hydrostatic Testing as an Integrity Management Tool

1 Scope

This technical report provides guidelines related to hydrostatic testing as a tool for integrity management in gas and liquids pipelines. It specifically focuses on program design and key parameters for consideration in hydrostatic test programs, as well as potential detrimental effects of hydrostatic testing. Several case studies (see Annex A) supplement the guidelines provided.

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 applies (including any addenda/errata).

API 579-1, *Fitness-For-Service*

API Specification 5L, *Specification for Line Pipe*

API Specification 5LX, *High-Test Line Pipe*

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 Recommended Practice 1160, *Managing System Integrity for Hazardous Liquids Pipelines*

ASME B31.4, *Pipeline Transportation Systems for Liquids and Slurries*

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

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

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

AGA NG-18 Report 194, *Hydrotest Strategies for Gas Transmission Pipelines Based on Ductile-Flaw-Growth Considerations*

Michael Baker Jr.., Inc. *Spike Hydrostatic Test Evaluation*. July 2004. OPS TT06

U.S. DOT Title 49, *CFR* Part 192, Subpart J—*Test Requirements*

U.S. DOT Title 49, *CFR* Part 195, Subpart E—*Pressure Testing*

Leis, B.N., et al. *Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures-Phase One.* Washington DC: s.n., 2013. G0060804.

McAllister, E.W. *Pipeline Rules of Thumb Handbook: A Manual of Quick Accurate Solutions to Everyday Pipeline Engineering Problems.* Gulf Professional Publishing: 2013

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

3.1.1
double stroke
The point where twice as many pump strokes are required to achieve the defined incremental increase in pressure as compared with when the pipe is in the elastic range, which can be shown to occur when the relationship between strokes and pressure increase is no longer linear and the slope of the line has been halved.

3.1.2
high-pressure test
A test undertaken at pressures potentially greater than necessary for qualifying test minimum requirements to address or assess for an identified or targeted pipeline threat. Similar in use to a "spike" test, an alternative when spike testing may not be advised or warranted.

3.1.3
hydrostatic test failure
A test failure that occurs when the pipeline, either due to leak or rupture of the line pipe, cannot either reach or sustain (if required) the target pressure of the hydrostatic test.

3.1.4
in-line inspection
ILI
The inspection of a pipeline using an internal inspection tool, commonly referred to as a "smart pig."

3.1.5
leak test
A test that can be performed with hydrostatic pressure (e.g. during a qualifying test) or in-service methods such as flame ionization (e.g. gas), in-line inspection (e.g. acoustic) means, or any other method suitable for discovery of leaks associated with the pipeline.

3.1.6
legacy pipe
Pipe manufactured with now-obsolete manufacturing methods, including low-frequency or DC ERW process, single submerged arc-weld, electric flash weld, wrought iron, lap welded, hammer welded, butt welded, and pipe made from Bessemer steel, or any pipe with a longitudinal joint factor less than 1.0 as defined in 49 CFR §192.113[5].

3.1.7
Maximum Allowable Operating Pressure
MAOP
Used when referencing natural or other gas pipelines operated under 49 CFR §192.

NOTE For the purposes of discussion of pressure test parameters, within this report this term is used interchangeably with MOP.

3.1.8
mill hydrostatic test
The hydrostatic pressure test of short duration (typically 5–10 seconds) applied in the pipe mill as part of the quality control process during original pipe manufacture.

[5] http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/NPRM_Safety_of_Gas_Trans_and_Gathering_Pipelines_3_15_16_final.pdf

3.1.9
mill test pressure
The test pressure applied in the pipe mill as part of the original manufacturing process of the line pipe.

3.1.10
Monte Carlo simulation
A statistical method of analysis that uses for input parameters a range of values (a probability distribution) that have inherent uncertainty. The subject calculation is performed using random values from the probability functions and repeated to produce a distribution of probable outcomes.

3.1.11
maximum operating pressure
MOP
MOP is the maximum operating pressure and is used when referencing hazardous liquids pipelines operated under 49 CFR §195.

NOTE For the purposes of discussion of pressure test parameters, within this report this term is used interchangeably with MAOP.

3.1.12
qualification test
A hydrostatic test that establishes at least the minimum required safety factor for the operating pressure of the pipeline based on accepted industry standards and regulatory requirements.

3.1.13
qualifying hydrostatic test
A test used for validation of the maximum operating pressure (MOP) of a pipeline system per regulatory requirements.

3.1.14
spike hydrostatic test
A pressure test conducted at a level significantly above maximum operating pressure and held for a short duration.

3.1.15
test pressure
A pressure above the working pressure of the pipe (such as MOP or MAOP) which the pipe is tested to verify pressure integrity.

3.1.16
specified minimum yield strength
SMYS
The minimum yield strength prescribed by the specification under which the material is purchased from the manufacturer.

3.2 Acronyms and Abbreviations

ACVG	alternating current voltage gradient
ANSI	American National Standards Institute
AOPL	Association of Oil Pipelines
API	American Petroleum Institute
ASA	American Standards Association

ASME	American Society of Mechanical Engineers
CEPA	Canadian Energy Pipeline Association
CFR	United States Code of Federal Regulations
DA	direct assessment
DCVG	direct current voltage gradient
DOT	United States Department of Transportation
ECDA	external corrosion direct assessment
EFW	electric flash welded (long seam)
ERW	electric resistance welded (long seam)
HAZ	heat-affected zone
HVL	highly volatile liquid (e.g. propane, butane, natural gas liquids)
INGAA	Interstate Natural Gas Association of America
ILI	in-line inspection
IMP	Integrity Management Plan
LFERW	low frequency electric resistance welded (longitudinal seam)
LOF	lack of fusion
MAOP	maximum allowable operating pressure
MFL	magnetic flux leakage (ILI technology)
MOP	maximum operating pressure
MP	mile-post or mile-point (on a pipeline)
NDE	nondestructive examination (e.g. radiography, ultrasonic inspection)
NTSB	United States National Transportation Safety Board
PCFA	pressure cycle fatigue analysis
PHMSA	United States Pipeline and Hazardous Materials Safety Administration
PRCI	Pipeline Research Council International
SSAW	spiral submerged arc welded
SCC	stress corrosion cracking
SMYS	specified minimum yield strength

4 Uses of Hydrostatic Testing—Understanding the Benefits

4.1 General

Hydrostatic testing of pipelines has been applied by the pipeline industry to establish maximum operating pressures and to manage specified threats to the integrity of pipeline systems. It is currently universally used to validate construction and pipe manufacturing practices prior to the commissioning of new pipelines. However, the use of hydrostatic testing for re-qualification (e.g. following change of service or establishing increased MOP or MAOP) or for integrity assessment varies greatly among pipeline operators; some companies rarely hydrostatically test lines under these circumstances, while others test hundreds of miles per year. Figure 1 illustrates that the use of hydrostatic testing as an integrity assessment is low when compared with ILI for both hazardous liquids and gas pipeline operators.

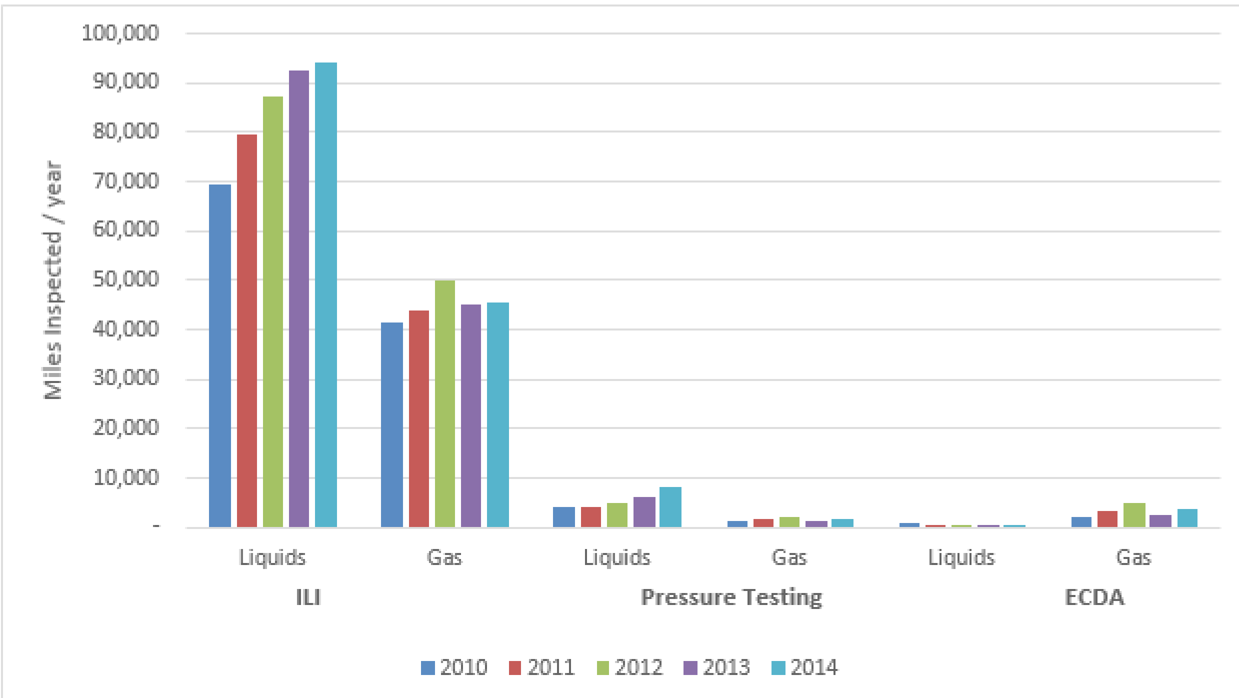

Figure 1—Transmission Pipeline Integrity Assessments 2010–2014

Pipeline operators generally choose hydrostatic testing as an integrity assessment tool when the following conditions exist:

— a pipeline segment is not configured for assessment using ILI;

— flow conditions make ILI impractical (e.g. low flow or low pressure or bi-directional);

— restrictions in the pipeline that limit the ILI ability to accurately detect or size anomalies;

— technology is not available to evaluate the identified threat(s) using ILI, or to qualify/validate a specific ILI technology;

— a large population of flaws is known or is suspected to exist that, based on conservative assumptions of material properties, would require an impractical remediation response.

Considering the range of conditions, objectives, and purposes that can apply to a hydrostatic test, the design of each test is an important element. The development of a test program and test objectives to support both integrity and operational objectives is also discussed in Section 6.

4.2 Qualification

In conjunction with applicable design requirements based on regulatory codes, qualifying hydrostatic tests are used to establish qualification for service based on minimum pressure test requirements. Both the United States and Canada have federal regulations requiring pressure testing to verify integrity and establish the MOP or MAOP of a newly constructed pipeline. A qualifying test can also be used to verify integrity at other times during a pipeline life cycle. A qualifying test is typically a one-time event that does not require subsequent testing unless so dictated by engineering assessment. Examples of where a qualifying test may be used include the following:

— new construction or pipeline replacement;

— change of operating conditions:

  — a significant increase in normal operating pressure;

  — reversal of flow direction.

— increase in MOP or MAOP (uprating);

— conversion to service or change in product;

— class location changes (gas pipelines); or

— validation of missing[6], unverifiable, or incomplete records used to support MOP or MAOP.

4.3 Integrity Assessment

Hydrostatic tests may be used as a means of confirming reliability of a previously in-service pipeline. A properly designed hydrostatic test can verify that pipeline threats have been adequately managed. Depending upon the threats assessed through the hydrostatic test program, these reliability tests may serve as a one-time assessment of threats or, alternatively, they may be part of a series of iterative integrity assessment steps.

ASME B31.8S and API 1160 provide guidance on applicability of hydrostatic testing for integrity assessment. These references state that hydrostatic testing can be used as an assessment for time-dependent threats[7] and threats that have the potential for enlargement by pressure cycle-induced fatigue. Time-dependent threats require periodic reassessment to ensure effective threat management. When used to assess time-dependent threats, each test should be designed to specifically target the relevant threat(s), with an objective to establish a reassessment interval with a desired safety factor. Gas pipeline operators are currently more likely than liquid operators to use hydrostatic testing to manage the threat of SCC due to difficulty with use of ultrasonic crack-detection tools in dry gas pipelines.

Hydrostatic testing can additionally be used as a one-time event to assess resident material threats such as manufacturing flaws not susceptible to time-dependent flaw degradation mechanisms, including evaluation of the pipe against the threat of defective longitudinal seam welds. For example, an operator may use a test to verify that ERW or other seam workmanship (e.g. legacy[8] manufacturing methods such as a lap-welded or hammer-welded seam) is not causing an unacceptably low factor of safety. Limited benefit is realized through hydrostatic testing for the assessment of circumferentially oriented defects, such as defective girth welds, as there is relatively little resulting stress in the pipe's axial direction and the primary stress is oriented in the hoop direction.

[6] This does not imply that a test is required any time records are missing. An effective strength of a pipeline system can be established by demonstrating an applied stress level without yielding of the pipe (refer to Section 6.5.4 for use of double stroke to limit yielding during hydrostatic testing).

[7] As defined by ASME B31.8S and API RP 1160.

[8] All seam types and manufacturing methods are subject to material flaws; however, "legacy" or pre-regulation pipe (prior to 1970) is typically deemed more susceptible due to manufacturing process and lower mill test pressures.

Hydrostatic testing can be used to establish confidence in an integrity management program, or in a process within an integrity management program. For instance, a test may be used to validate an ILI process. This validation objective could extend beyond that of ILI data analysis processes to include vendor selection, qualification, inspection, excavation, field nondestructive examination (NDE), and repair methods.

5 Elements of a Test Program—Definitions

5.1 General

There is broad interpretation within the pipeline industry regarding requirements and definitions for various aspects of pressure test programs.

The focus of this section is to provide consistent parameters for consideration to aid in classification of a hydrostatic test, and the definitions below are presented to provide consistent terminology for application in consideration of pressure testing. It should be noted that "integrity test," a widely-used generic testing term, has not been specifically applied within this report; it is considered that each of the tests described below are a form of integrity test.

This section of the document does not include provisions for determining when and how to apply a hydrostatic test, recommendations on which testing type is most appropriate, or defining the test's objectives. Target hydrostatic pressures are driven by the hydrostatic test's goals, the pipeline's characteristics, the integrity threats being evaluated, consideration of all associated risk factors, and the supporting engineering analyses.

A theoretical application of testing definitions is provided in Section 5.9 of this document.

5.2 Test Pressure Stress Level

When discussing hydrostatic test stress levels, it is common in the pipeline industry to refer to the test pipe that will be exposed to the highest ratio of the stress levels during the test and SMYS (e.g. a test to 90 % SMYS). The location of this limiting pipe is not necessarily associated with the location of maximum test pressure. It is noted that stress level is a measurable component of the pipe material; this useful shorthand is important to understand for anyone designing a hydrostatic test.

5.3 Mill Test Pressure

Mill test pressure is the test pressure applied in the pipe mill as part of the original pipe manufacturing process. Since 1928, every joint of pipe manufactured to API 5L specifications has been required to pass a mill pressure test. Over the years, the test pressure specified has increased, and the test hold time has varied between 5 and 10 seconds. For situations where pipeline historical records are incomplete, yet the manufacturing or installation date is known, the API 5L or 5LX specification applicable at the time of pipe manufacturing may be used to estimate mill test pressure.

For larger pipe diameters (20 in. and larger OD), current API 5L mill test minimum requirements generally achieve equivalent stresses near 100 % SMYS, even when the uniaxial hoop stress may not be that high. Compressive longitudinal force applied to seal the ends of the pipe during the test sequence effectively brings the applied stress during the test closer to yield. Refer to Annex C.2.1 for additional explanation of von Mises equivalent stress.

5.4 Leak Test

A leak test can be performed via either hydrostatic test (e.g. as part of a qualifying test), flame ionization (gas) survey, in-line inspection (acoustic methods), or any other method suitable for discovery of leaks on the right-of-way. This is typically done in conjunction with any hydrostatic test program.

5.5 Qualifying Hydrostatic Test

A qualifying hydrostatic test establishes at least the minimum required safety factor for the MOP or MAOP of the pipeline based on the achieved ratio between test pressure and MOP or MAOP as per accepted industry standards and regulatory requirements.

5.6 High-pressure Test

A high-pressure test is undertaken at pressures potentially exceeding minimum requirements of a qualifying test to address or assess an identified or targeted pipeline threat. Testing to pressures consistent with minimum requirements for a qualifying hydrostatic test may not provide the targeted level of reliability assessment, especially for pipelines with low operating stress at MOP or MAOP. There is no maximum level for a high-pressure test, but it should be noted that test pressures may be limited by design strengths of limiting components such as pipe or pressure- and temperature-rated components.

High-pressure testing, like spike testing, can serve as a basis for the extension of reassessment intervals by removing subcritical-sized flaws, thus reducing the dimensions of surviving flaws and increasing the time to failure for remaining time-dependent threats. Spike testing, which is discussed below in the context of minimum pressures based on material properties, may not always be warranted or advised; high-pressure testing, in conjunction with engineering analysis, is intended to provide a viable alternative to spike testing in these cases.

The following minimum requirements should be met to perform a high-pressure hydrostatic test:

— test pressure level at or above that of a qualifying hydrostatic test; and

— test pressure established is based on the integrity threat and the estimate of the continuing deterioration rates to ensure reliable future operations.

High-pressure tests, unless also being used for the purposes of a qualifying test, may be of any duration necessary for management of a target integrity threat.

5.7 Spike Hydrostatic Testing

5.7.1 General

A spike hydrostatic test achieves a test pressure at a level significantly above maximum operating pressure and held for a short duration to identify and eliminate near-critical resident imperfections and limit unnecessary growth/damage to any remaining imperfections. The sustained hold period that usually follows a spike test is typically at least 10 % below the spike test level. Spike testing has application for addressing time-dependent cracking threats, such as SCC, selective seam corrosion, and manufacturing threats such as seam weld anomalies susceptible to growth through fatigue. Pipeline operators may also perform a spike test to establish in-place yield strength or, if yielding does not occur, to establish a lower bound for the yield strength (refer to Section 6). From a technical standpoint, the strength of the pipe is established during the spike test period, and the qualification test period is essentially a leak test. The likelihood of a test failure at the lower hold pressure following a successful spike test of any duration is low, and the advantage is that for simplicity, the test records can be considered distinct.

A spike test is not performed on a stand-alone basis, but instead is generally a sub-element within an established hydrostatic test program, as described within this document. The spike portion of the test program is not generally considered the final element in the testing sequence. A qualifying test or leak test should follow the spike test[9]. The purpose of this testing sequence is to ensure that any existing leak-type flaws that remain in the pipeline following the spike test are discovered during subsequent testing.

---

[9] The qualifying test, or leak test, is not required to immediately follow the spike portion of the test. Some operators discussed test sequences where, due to operational considerations, the spike test and qualifying test were performed days or weeks apart as part of an overall test program.

Using the terminology established within this report, a spike test and a high-pressure test have similar utility. Both are intended to eliminate near-critical flaws and to achieve a higher level of reliability than is possible at lower test pressures. Test pressure targets are based on the target integrity threat(s) and (if required) an assessment interval is established based on an estimate of the continuing deterioration rates.

5.7.2 Spike Test Pressure Level

Pipeline operators report varied interpretations of "spike," including 1.25 x MOP, a percentage over 1.25, a pressure level (e.g. 50 psig) above qualifying test, or a pressure to produce a stress level in the nominal pipe between 100 % and 110 % SMYS.

It has been recognized in this work that any test pressure greater than 125 % of MOP or MAOP would meet the API RP 1110 definition of a spike test, and subsequent minimum spike test targets could vary from 25 % to 90 % SMYS (assuming normal MOPs ranging from 20 % to 72 % SMYS). The term "spike test" carries a certain connotation that a pipeline subjected to a pressure test greater than the qualifying test is safer and more reliable, yet consistent application of the term presents a challenge for the pipeline industry, as such widely applied test pressure targets provide varied assessments of pipeline integrity, especially when considering the threat of manufacturing defects.

5.8 Spike Testing Pipelines with Planned Low Operating Stress

Testing to pressures that correspond to hoop stress levels between 100 % and 110 % SMYS is discussed in the American Gas Association (AGA) Topical Report NG18 Number 194[10] for removal of flaws that might cause failure in service. It was recognized that these stress-level targets were not necessarily meant to apply to pipelines operating at lower stress levels. The report further stated that the test pressure should be lowered by 10 % following the spike test to minimize the likelihood of flaw growth.

TTO 6 (TTO6)[11], a report funded by the U.S. DOT in 2004, provides spike test guidance for application to pipelines operating at lower stress levels. The report notes that the concept of a spike test is valid for pipelines operating at less than 72 % SMYS; however, test pressure targets of 139 % to 153 % of MOP (equivalent to a stress level of 100 % to 110 % SMYS when operating at 72 % SMYS), do not necessarily result in an optimum assessment of pipeline integrity, due to the potential for remaining flaws (e.g. flaws that survive the spike test and subsequent test program) to undergo slow ductile tearing and grow in size to become susceptible to fatigue in service.

Two formulae are presented in TTO6 that identify spike test pressure targets from 139 % to 264 % of MOP depending on the target threat and the operating stress of the pipeline. However, the report cautions that it is "unrealistic to expect an operator to pressurize a pipeline comprised of older ERW pipe to a pressure level exceeding the equivalent of 100 % of SMYS."

When spike testing to assess the threat of manufacturing defects, such as the potential for defective ERW longitudinal seams, it is beneficial to consider a stress-level target based on the pipe material rather than simply a multiple of MOP or MAOP. It is presented here that selected target spike test stress levels should be benchmarked for feasibility against the actual stress levels achieved during mill testing (if known), previous field hydrostatic testing, or the minimum mill test pressures required within the applicable version of API 5L or API 5LX. The rationale and objectives for this consideration are twofold, and are as follows:

A spike test that achieves a stress level equal to or greater than prior stress levels should do the following:

1) Demonstrate that no significant time-dependent degradation has occurred to resident flaws that could exist in the longitudinal seam.

2) Suggest a reasonable test pressure target level based on the expected material properties of the line pipe steel, which should not result in an excessive number of test failures when applied.

[10] Leis, B.N. and Brust, F.W. *Hydrotest Strategies for Gas Transmission Pipelines Based on Ductile-Flaw-Growth Considerations*. s.l.: PRCI, 1992. Catalog No. L51665.

[11] Baker, Michael Jr. Inc. *TTO-6 – Spike Hydrostatic Test Evaluation*, July 2004.

The following criteria should be considered for a spike hydrostatic test:

— a test pressure level at or above that of a high-pressure test; and

— a test pressure level established based on the target integrity threat and an estimate of the continuing deterioration rates to ensure reliable future operations.

When testing for the purposes of evaluating seam weld manufacturing threats, a test pressure level at least equal to the minimum required mill test pressure is necessary if a test objective is to demonstrate that no significant time dependent degradation has occurred. If mill test pressures are unknown or unavailable, applicable minimums required by the API 5L or API 5LX version at the time of pipe installation can be used. (These are summarized in Table 1 and Table 2).

Although there is no upper limit to spike test pressure levels, test pressure levels that greatly exceed historical mill test pressures or are above 100 % SMYS should be carefully considered to ensure that the benefits outweigh the potential detrimental effects.

Table 1—API 5L Minimum Mill Test Pressures

Year	API 5L Edition	Specification	Mill Test Pressure (min)
1928–1941	1st	Varies by process/grade	40 % SMYS
1942–1982	8th	Varies by process/grade	60 % SMYS
1983–Present	33rd incorporated 5L, 5LX, and 5LS	Grade A25, A, B	60 % SMYS
		X42–X80	60 % SMYS for OD < = 8 $^5/_8$ 85 % SMYS for OD > 8 $^5/_8$ and < 20 90 % SMYS for OD > = 20

Table 2—API 5LX Minimum Mill Test Pressures

Year	API 5LX Edition	Specification	Mill Test Pressure (min)
1948–1952	1st	X42	85 % SMYS
1953–1956	4th	X42, X46, X52	75 % SMYS for OD ≤ 8 $^5/_8$ in. 85 % SMYS for OD > 8 $^5/_8$ in.
1956–1961	6th	X42, X46, X52	75 % SMYS for OD ≤ 8 $^5/_8$ in. 85 % SMYS for OD > 8 $^5/_8$ in. 90 % SMYS for seamed pipe OD ≥ 20 in.
1959	Supp. to 8th	X42, X46, X52	90 % SMYS for seamless pipe OD ≥ 20 in.
1962–1982	10th	X42, X46, X52	60 % SMYS for OD = 4.5 in. 75 % SMYS for OD ≤ 8 $^5/_8$ in. 85 % SMYS for OD > 8 $^5/_8$ in. 90 % SMYS for OD ≥ 20 in.

5.8.1 Spike Test Duration

Stabilization of the test pressure is not required during a spike test; it is only necessary to verify that the test pressure remains above the target minimum pressure for the duration of the spike test period. This approach is supported by the following guidance taken from API 1160: "A spike test is not intended to be a leak test, and generally no attempt is made to look for leaks." The hold-time portion of the test to look for leaks can be performed after the spike test by lowering the test pressure to the minimum required value for a qualifying test.

Various accepted industry resources recommend various hold times though no source recommends durations longer than one hour. NG-18 Report 194 recommends a one-hour maximum hold time for spike testing. ASME B31.8S recommends a 10-min minimum test duration when testing for management of SCC. TTO6 recommends a 30-min test duration; however, that reference acknowledges that the best hold time for integrity purposes depends upon factors that include the numbers and sizes of defects present in the pipeline. Other references also cite hold times; the above are presented to illustrate the wide variance in recommendations.

A spike hydrostatic test is effective for integrity management even if conducted with a test hold time of only several minutes. Limits to the test duration are intended to minimize the potential for detrimental effects to the pipeline. NG-18 Report 111[12] states that "hold time at maximum pressure should be minimized as it causes remaining subcritical defects to grow." Other technical work[13] supports test durations on the order of 5 minutes.

Test durations should be determined by the pipeline operator and kept as short as possible. Test durations ranging from 3 minutes[14], [15] to 10 minutes are appropriate for an effective spike test. Test durations should consider section length to ensure that pressure is above the target minimum throughout the segment being tested. For additional discussion, see Section 7.3 of this report.

5.9 Application of Definitions

Table 3 and Table 4 are provided to clarify application of the test pressure definitions discussed in this document. The terms "qualifying," "high pressure," and "spike" are not intended to limit an operator's design of a test for management of pipeline integrity. It is possible that a pressure test may fit multiple goals. As shown in Table 3, a high-pressure test for a pipeline operating at 72 % SMYS is a test designed to manage a specific threat; if the pipeline is intended to operate at the maximum typical pressure allowed by regulation, this pressure test also coincides with "qualifying" and "spike" pressure level targets. Contrast this circumstance to a high-pressure test designed to establish a specific test interval for a pipeline operating at 50 % SMYS.

Table 3—Example Stress Levels for Modern Line Pipe ≥ 20 in. and ≥ X42

	Stress Level			
Pipeline MOP	**72 %**	**50 %**	**30 %**	**20 %**
Mill pressure test (API 5L minimum) [a]	90 %	90 %	90 %	90 %
Qualifying test target minimum (1.25 x MOP)	90 %	63 %	38 %	25 %
High-pressure test target minimum	> 90 %	> 63 %	> 38 %	> 25 %
Spike test target minimum when assessing for time-dependent cracking threats	> 90 %	> 90 %	> 90 %	> 90 %

[a] Note that in some instances, particularly for smaller outside-diameter and/or heavier wall pipe, the required pressure level may exceed the mill capability. API 5L provides for these limitations.

Table 4 shows a similar relationship between the types of tests for a legacy line pipe; in this case, a 20-in. OD X42 manufactured under the applicable API 5L specification in 1952. The fact that test pressures are required to exceed the mill test pressure illustrates the potential difficulty when specifying a high- or spike-pressure test in excess of historical test pressures.

A pipeline operator may find it difficult to achieve a qualifying test as required to operate at 72 % SMYS, and alternatives may have to be considered, such as lowering the MOP of the pipeline to a level where the qualifying test would require pressures in line with historical pressures on the pipeline.

The case study in Section A.4.1 presents a scenario where a hazardous liquids pipeline operator attempted to test a pipeline to levels exceeding historical mill test pressures and multiple test failures were experienced. The solution in that case was to lower the test targets and establish a maximum operating pressure based on a lower qualifying test.

---

[12] Kiefner, J.F., Maxey, W.A., and Eiber, R.J. *A Study of the Causes of Failures of Defects That Have Survived a Prior Hydrostatic Test*. NG-18 Report 111, November 3, 1980.

[13] Kiefner, J.F., Maxey, W.A. "The Benefits and Limitations of Hydrostatic Testing," API Pipeline Conference, San Antonio, April 18–19, 2001.

[14] Rosenfield, M.J., Ma, J. "Rational Test Pressure Levels for Mitigating the Pipe Manufacturing Defect Integrity Threat in Natural Gas Pipelines," Pipeline Pigging and Integrity Management Conference, Houston, February 8–11, 2016.

[15] Macrory-Dalton, C., Rosenfield, M.J., Steiner, A., Zand, B., "DTPH5616T00009 Development of Comprehensive Pressure Test Guidelines – Task 8," Kiefner Final Report No. 18-060, September 4, 2018.

Table 4—Example Stress Levels for 1952 Constructed Legacy 20 in. X42 Line Pipe

	Stress Level			
Pipeline MOP	**72 %**	**50 %**	**30 %**	**20 %**
Mill pressure test (API 5L minimum)	85 %	85 %	85 %	85 %
Qualifying test target (1.25 x MOP)	90 %	63 %	38 %	25 %
High-pressure test target	> 90 %	> 63 %	> 38 %	> 25 %
Spike test target minimum when assessing for time-dependent cracking threats	> 85 %	> 85 %	> 85 %	> 85 %

5.10 Additional Considerations When Spike Testing

When a qualifying test is performed in conjunction with a spike test, some operators consider the tests to run simultaneously while others do not. Operators surveyed indicated that when spike hold times were relatively short (e.g. 30 minutes or less), the qualifying test following the spike test was generally held under test for the full qualifying test time requirement. For example, a 30-min spike followed by a qualifying test for a duration of 8 hours would result in a total test period of at least 8.5 hours. For pipeline operators adhering to internal procedures that stipulate spike hold times of 1 hour, the qualifying test hold time was typically applied as the remainder of the qualifying test time requirement.

While both are defendable, it is advantageous to design any test program to include the full applicable qualifying test time requirement following a spike test. From a technical standpoint, the strength of the pipe is established during the spike test period, and the qualification test period is essentially a leak test. The likelihood of a test failure at the lower hold pressure following a successful spike test of any duration is low, and the advantage is that, for simplicity, the test records can be considered distinct.

6 Design of a Test Program

6.1 General

The primary objective of a hydrostatic test when used for integrity management is to achieve a threat-specific target reliability at the operating pressure of the pipeline.

The benefits of hydrostatic testing are demonstrated in the ratio of the test pressure to the operating pressure and the relationship between failure pressure and flaw size. Regardless of test objectives, a higher test pressure would result in smaller theoretical flaws surviving the test, and therefore an increased operational reliability. A hydrostatic test demonstrates that any surviving flaws have a failure pressure (at the time of the hydrostatic test) at least as high as the test pressure. A hydrostatic test is designed to achieve established objectives and should generally be designed to achieve as high a pressure differential ratio as possible, thus achieving maximum integrity benefits while still supporting other test objectives.

Hydrostatic testing can provide value in managing the recognized pipeline threats of external corrosion, internal corrosion, stress corrosion cracking, prior mechanical damage, and manufacturing defects such as defective pipe or defective longitudinal seam welds. Each of the above threats, if considered present within the test section, should be treated differently as there is no “one-size-fits-all” test program.

To illustrate this, consider a test program designed to target the threat of SCC. The recommended minimum test pressure for the threat of SCC, per ASME B31.8S, is above 100 % SMYS. If legacy pipe is subjected to a test pressure exceeding historical mill or field test pressures, growth and unnecessary failure of benign manufacturing flaws (e.g. ERW longitudinal seam weld flaws) during the test may result. Selection of test pressures should address not only primary reliability objectives, but operational, environmental, and safety considerations, as well. If test pressures are limited due to material limitations within the pipeline system or expected activation and failure of non-target flaws, a certain level of reliability can still be achieved through testing to highest reasonable levels at decreased test intervals. Such test intervals can be established and adjusted accordingly, or engineering assessments can be performed supplementary to a test program. The case study in Section A.2.1 illustrates a risk-balanced approach to the development of test objectives.

6.2 Development of Test Objectives

Multifaceted test objectives should clearly and directly address likelihood and consequence, thereby providing a risk-balanced approach in the development of the technical scope and execution plan. Objectives to be addressed in any hydrostatic test include the following:

— establishing a safety margin for the threat program to conclude that the pipe is not susceptible to rupture at MOP or MAOP for a defined time period;

— minimizing unnecessary impact on benign resident manufacturing flaws;

— minimizing the potential for adversely affecting public safety and personnel safety, and minimizing environmental impacts associated with release of test water; and

— minimizing adverse customer and associated commercial impacts.

If a target test pressure to satisfactorily evaluate a specific threat and achieve the target reliability is significantly above historical field or mill test pressures, the operator should fully weigh the risks and benefits of attempting to test to these levels. Test objectives and test pressures may need to be adjusted, reassessment intervals shortened, or operating conditions altered to achieve acceptable confidence in continued operation. Figure 2 provides a flowchart of the development process.

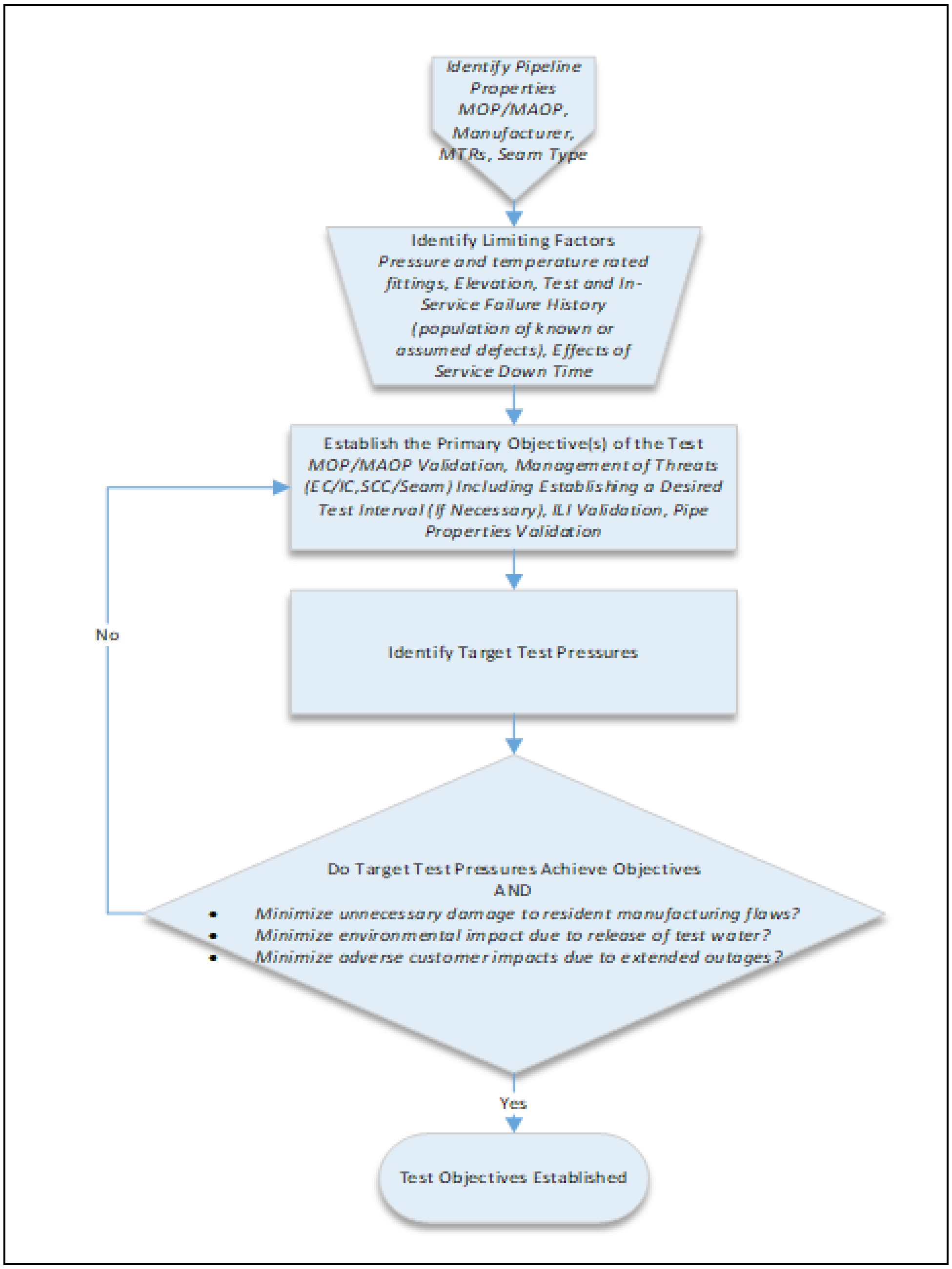

Figure 2—General Development of Test Objectives

6.3 Required Test Pressures

Code documents and regulations typically set required test pressures for qualification tests (e.g. ASME B31.4, ASME B31.8, 49 CFR §192 and §195 in the U.S., and CSA Z662 in Canada).

All pressure tests provide some level of integrity assurance about pipeline integrity; however, using the definitions from Section 5, high-pressure and spike tests are designed to be threat-specific. Each requires consideration of the known or assumed population of defects present on the pipeline and desired intervals for reassessment. Test pressure targets should be as high as practicable; they may be adjusted based on a variety of local factors. If maximum reassessment intervals are prescribed by regulation, the utility of high-pressure or spike testing may be limited. The tests may not be able to extend the assessment intervals, yet could increase the risk of test failures, potentially resulting in unacceptable safety, operational, societal, or environmental risks.

6.4 Development of a Hydrostatic Pressure Profile

6.4.1 General

At a constant test pressure, the internal pressure of the pipeline during the test will vary inversely with increased pipeline elevation due to hydrostatic pressure head effects. The highest test pressure will be at the lowest elevation point of the pipe section and the lowest test pressure will be experienced at the highest elevation point. This relationship is best illustrated through development of a hydrostatic pressure profile for the test segment. An example is shown in Figure 3.

In Figure 3, a theoretical pipeline with ~500 vertical ft of elevation change over 14 miles shows that test pressures along the pipeline can vary by ~215 psig. Development of target test pressure ranges shall consider the location of the low and high points, as well as the location of the control point for measurement of the test.

When determining a hydrostatic test pressure as a percentage of SMYS, the operator should consider the material properties and wall thicknesses of the entire pipeline segment and overlay these characteristics on the hydrostatic profile as demonstrated in Figure 3.

Failure to properly consider pipe properties in application with the elevation profile of the pipeline may result in areas of pressure within the pipe segment that either do not meet or far exceed target levels. In the profile illustrated in Figure 3, the pipeline segment between MP 3.4 and MP 3.6 exists at a local low point and coincidentally exhibits the limiting component within the test segment.

As illustrated, the increased test pressure resulting from the low elevation and hydrostatic pressure head effects will exceed SMYS of the pipe material. If the pipe has not been previously tested to this level, the likelihood of a test failure is increased. Conversely, the section of pipe between MP 10 and MP 14.6 will experience lower relative stress. This could be due to either heavier wall or stronger material. Depending upon objectives, target stress levels may not be met.

If necessary, alternative test program parameters can be implemented, including segmentation of the pipeline section into multiple test sections to account for elevation variances and increased pressures, revision of test objectives, or testing to lower stress levels, and adjusting operating pressure or re-inspection intervals.

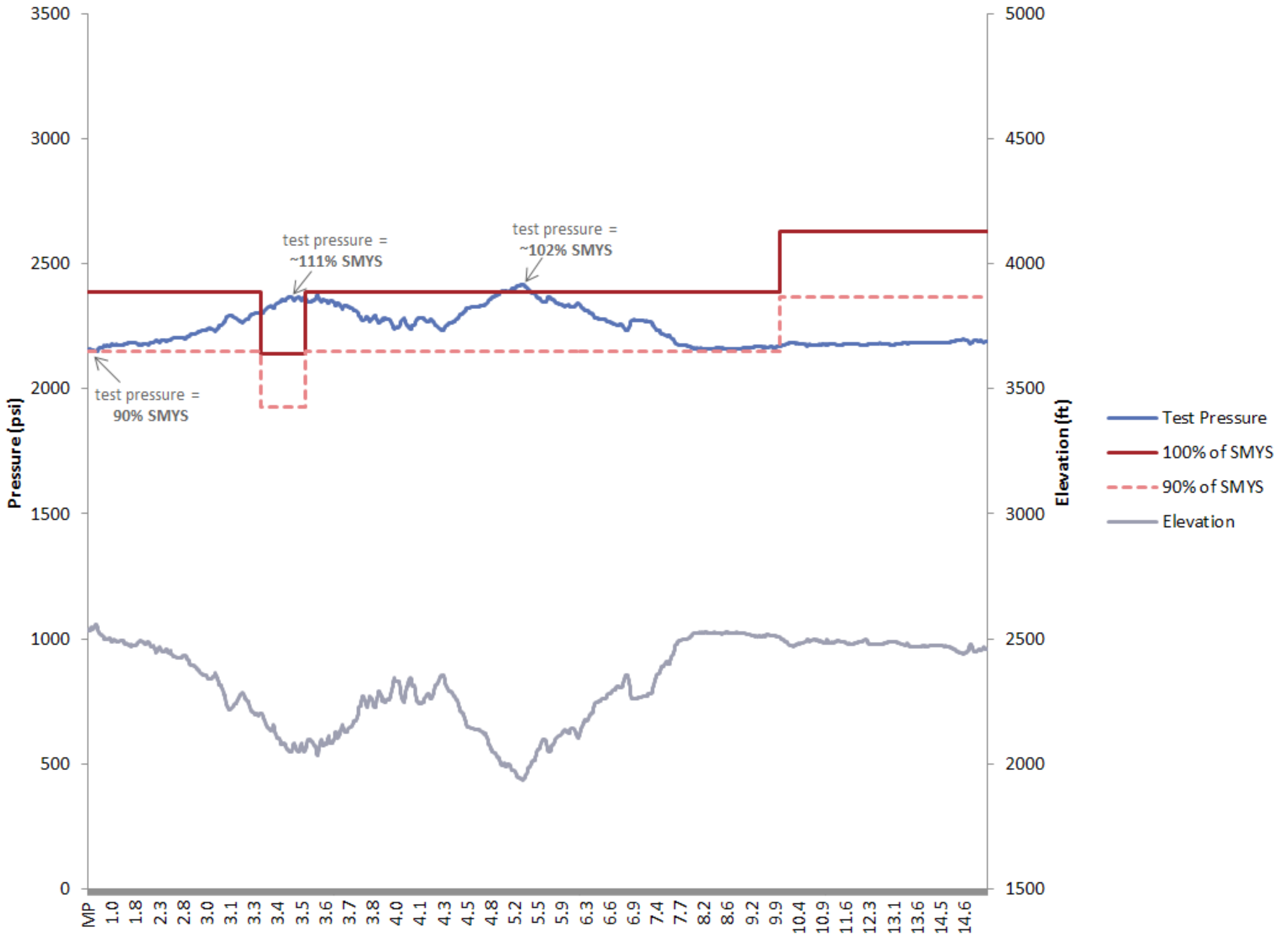

Figure 3—Hydrostatic Pressure Profile of a Theoretical Pipeline Segment

6.5 When to Terminate a Test

6.5.1 General

The final step in design of the test program is to define the parameters for test completion and/or termination. Completion can be when the program has achieved the target test pressure for the specified duration (thus successfully assessing the pipeline for the targeted threat and intended safety factor and/or establishing the desired reassessment interval) or, in the case of unintended outcomes, when the original test program should be repeated, adapted, or abandoned. Unintended outcomes may include the following:

— failures below the targeted test pressure, including pressure reversals (refer to Section 6.5.3);

NOTE One or two failures do not necessarily constitute unintended outcomes. In many cases, they are expected. It is when they become excessive that one would consider them unintended.

— failure upon reaching target test pressure;

— failure during the spike portion of the test;

— double deviation of the P-V plot (e.g. double stroking) (refer to Section 6.5.4); or

— leaks.

6.5.2 Test Failures

If a test failure is experienced, the test is considered to be unsuccessful unless the test can be successfully repeated and target test pressures achieved following repair or replacement of the failed pipe section. Refer to API 1160.

Multiple failures during testing may suggest a systemic issue on the pipeline segment (e.g. a longitudinal seam weld condition discovered because the pipe in the section had never been tested to the higher pressure now targeted). The analysis of the failures may suggest the potential for many more similar conditions to be present. The operator may then decide that the test pressure at failure, if successfully repeated, should become the basis for a reduced reassessment interval or a reduction in maximum allowable operating pressure. If the defect that resulted in failure is expected to be isolated, the operator may elect to conduct a subsequent test as per the original test requirements.

6.5.3 Pressure Reversals

It is recognized that the presence of longitudinal seam weld defects (e.g. lack of fusion, stitching, cracking) or pipe body cracking (e.g. SCC) can reduce the pressure-carrying capacity of the line pipe. In cases where these flaws may grow by slow ductile tearing during the test sequence, but just survive either due to another defect failing or the test being terminated, there is the possibility that the flaws could fail at a lower pressure upon re-pressurization. This is commonly referred to as a pressure reversal and, simply put, is a failure that occurs at a pressure less than the previous test pressure. This can occur even when no time-dependent degradation effects have contributed to the failure.

Based on historical research and experience gained through hydrostatic programs (typically qualification tests), the likelihood of a pressure reversal is known to be inversely proportional to its magnitude. Most of the pressure reversals that have occurred are generally within 10 % of the prior test pressure. With test pressure-to-operating pressure ratios consistent with qualification tests (1.25 or higher), the near-term likelihood of a failure at MOP or MAOP of a defect due to a pressure reversal is generally negligible.

6.5.4 Double Stroke of the Pressure-Volume Plot

When a positive displacement pump is used, the number of strokes (volume of test water added to the pipeline) required to increase the pressure level can be recorded. This can be done for the entire test duration; many pipeline operators' procedures commence specific monitoring when the pressure reaches a level corresponding to ~80 % SMYS of the limiting pipe involved in the test. Prior to any pipe yielding, when the stress in the pipeline is within the elastic range, the relationship between the number of strokes and pressure increase is linear and is the basis for the pressure-volume plot (refer to Figure 4).

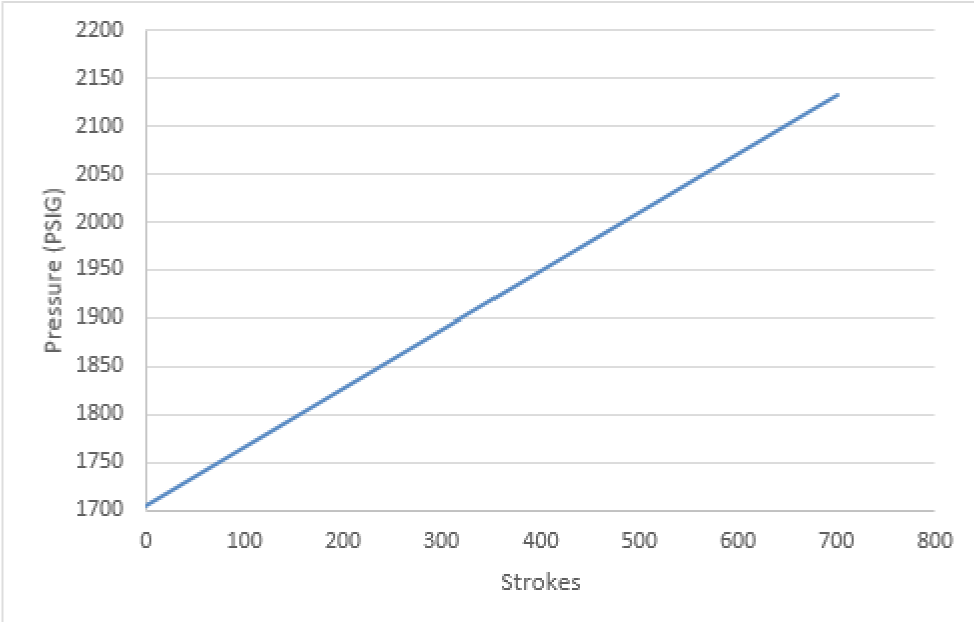

Figure 4—Example of a Linear P-V Plot

If internal pressure reaches levels that exceed the elastic limit of the material, the pipe will begin to plastically deform, and a greater volume will be required to achieve an incremental pressure increase. A double stroke is defined as the point where twice as many pump strokes are required to achieve the defined incremental increase in pressure as compared with when the pipe is in the elastic range, which can be shown to occur when the relationship is no longer linear, and slope of the line has halved. This is shown graphically in Figure 5.

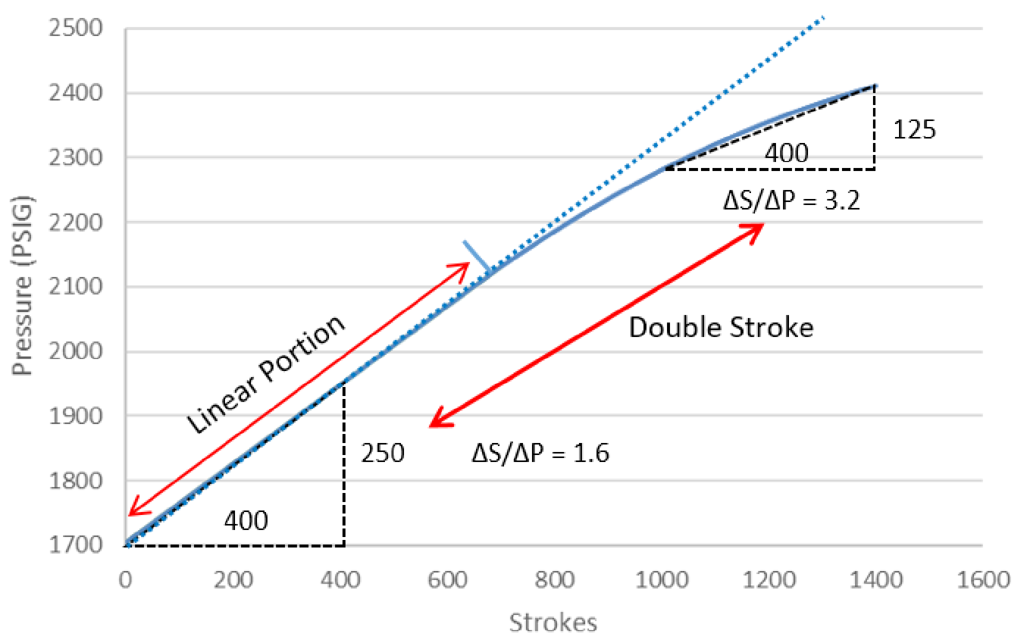

Figure 5—Theoretical Example of a P-V Plot for a Double Stroke

Per 49 CFR §195.406, refer to Appendix N of ASME/ANSI B31.8 when determining maximum operating pressure when hydrostatically testing a pipeline.

Higher strength and newer materials will likely have less variance in yield strength; therefore, the chance of pipe joints sustaining 0.5 % strain is low. Older vintage materials typically have a broader range of SMYS, and some pipe joints could reach 0.5 % total strain.

Consistent with Appendix N of ASME/ANSI B31.8, when the number of strokes doubles, this has been historically assumed to be the yield point. This assumption is conservative, but is inaccurate as it relates to the offset yield strength. Double stroking occurs just after the pipe exceeds its elastic limit and the material has plastically deformed a small amount, but most likely, none of the pipe joints will have reached the offset yield strength, which is defined as the stress required to produce 0.5 % total strain.

6.5.4.1 Defining and Modeling Yield Strength in Pipeline Steel

Pipeline stress-strain responses can often be represented through a power-law relationship. One of the most commonly used relationships is the Ramberg-Osgood expression, as shown in Equation 1.

$$\varepsilon = \frac{\sigma}{E_s} + \varepsilon_{py}\left(\frac{\sigma}{\sigma_y}\right)^n \qquad (1)$$

Where:

ε_{py}	$0.005 - \sigma_y/E_s$;
ε	strain;
σ	stress;
ε_{py}	plastic strain component (or yield offset) up to the total defined strain (0.5 %);
E_s	Young's modulus, equal to the elastic part of the stress-strain curve up to the elastic limit;
σ_y	the defined yield stress; and
n	the Ramberg-Osgood exponent, a fitted parameter,

Figure 6 shows the Ramberg-Osgood fitted curve as compared with an actual stress-strain curve for an X70 pipe with a yield strength of 83,500 psi, ultimate tensile strength of 99,500 psi, and modulus of elasticity (Young's modulus) of 29,600,000 psi. The curve developed by the Ramberg-Osgood expression reasonably matches the curve from the tensile test. It is important to note the location of the elastic limit and the offset yield strength. The elastic limit defines the end of the straight-line portion defined by Young's modulus, and ε_{py} is the plastic strain component prior to reaching the defined yield point strain of 0.5 %.

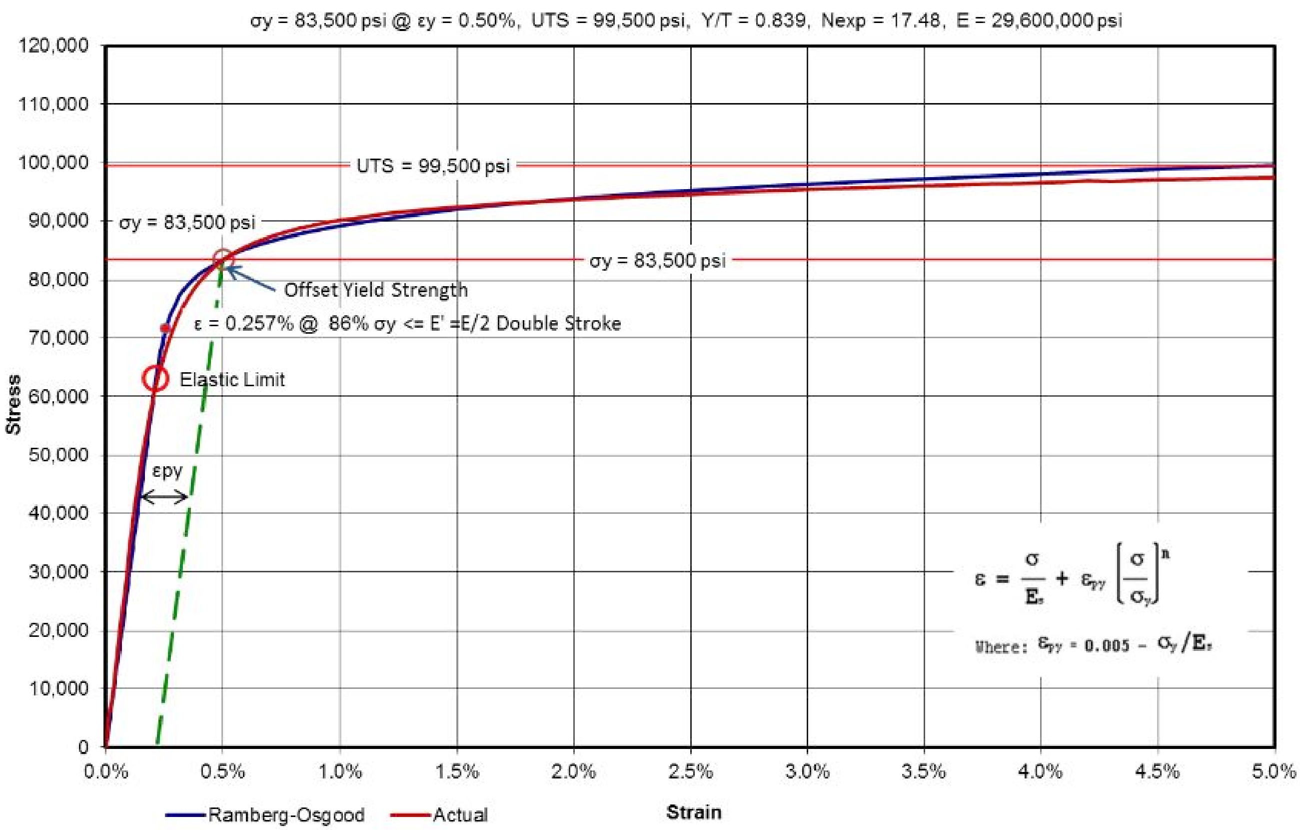

Figure 6—Ramberg-Osgood Stress-Strain Curve of Actual X70 Pipe

It is often overlooked that "yield," or SMYS, typically reported at 0.5 % strain, is a definition and not an actual description of the yield point itself. In nearly all steels, plastic deformation starts before reaching 0.5 % strain. As can be seen in the diagram presented in Figure 6, the slope of the elastic modulus has diverged from linear, indicating a level of plastic deformation, prior to 0.5 % strain.

The double-stroke method is useful as a conservative estimation of yield strength and to limit the potential for actual yielding in the section being tested. When using double-stroke hydrostatic testing, it is important to understand that just because a double-stroke event has occurred, the pipeline has almost certainly not undergone uniform yielding. Furthermore, it is important to note that double stroke will not occur at the same test pressure for all sections of a pipeline being hydrostatically tested. The test pressure where double stroke will occur is dependent on material property variation, wall thickness variation, elevation, temperature, and the Bauschinger effect (refer to Annex C.2.3), and a relatively small number of lengths may account for double stroke in a longer test section.

6.5.5 Leak During a Hydrostatic Test

If a leak is experienced during a qualifying hydrostatic test, then generally, the test is discontinued, the leak repaired, and the test repeated. Specific regulations for qualification testing should be consulted to determine the validity of a hydrostatic test if leakage occurs[16]. From an integrity management perspective, evidence of a leak does not necessarily invalidate a hydrostatic test for management of specific pipeline threats. If target pressures can be maintained, the hydrostatic test can still be completed successfully and demonstrate the strength of the pipeline system (although not the absence of leaking defects).

The pressure within a pipeline test segment may not stabilize during the short time duration associated with a spike or high-pressure test, and this may make identification of a leak difficult or impossible. Longer test dura-

[16] 49 CFR §195.302 (a) "…no operator may operate a pipeline unless it has been pressure tested under this subpart without leakage. In addition, no operator may return to service a segment of pipeline that has been replaced, relocated, or otherwise changed until it has been pressure tested under this subpart without leakage."

tions (e.g. 30 minutes to 1 hour) may stabilize pressure sufficiently for leakage to be identified. It is reasonable to add water to maintain the pressure targets during this phase of the test, recognizing that the subsequent leak test should address any potential leaks. If test pressures can be maintained by adding water, the strength of the material is still demonstrated. This may be helpful in minimizing largest stress cycles; for example, those that would result from stopping and restarting a spike test.

A case study is presented in Section A.2.1 where a test plan was developed that included a plan to continue to pump if a leak was experienced and it could be confirmed that the leak was not due to a condition that would grow during the test (e.g. pipe yielding or growth of the leaking anomaly).

6.6 Test Acceptance and Interpretation

Each hydrostatic test plan should include criteria for achieving a successful test as the objectives may vary widely among tests conducted. If target test pressures are achieved and maintained, the pipeline segment will have successfully passed the integrity assessment. API 1110 contains further guidance on acceptance criteria as applicable to hydrostatic testing.

6.7 Determination of Assessment Intervals

6.7.1 General

When hydrostatic testing is used for management of time-dependent threats, the assessment should be repeated on a schedule to ensure ongoing integrity of the pipeline over time. Often, applicable regulation (e.g. state, provincial, or federal) defines maximum test intervals. However, the analysis should be completed because, depending on populations of flaws present on the pipeline and growth rates, intervals may need to be adjusted if intervals shorter than the prescribed regulatory maximums may be required. The assessment interval is calculated based on the series of flaw(s) that could exist in the pipeline following the hydrostatic test, in application with the applicable growth or deterioration rate of the flaw.

6.7.2 Calculation of Remaining Flaws, Post-Hydrostatic Test

6.7.2.1 General

The analysis for determination of test intervals can be demonstrated by plotting the family of curves, which represent failure pressure versus flaw size for a pipeline, as shown in Figure 7. A figure such as this can be generated for any pipeline using the applicable pipe properties, and this specific figure is applicable for evaluation of blunt flaws (e.g. corrosion) on the sample pipeline.

Figure 7 shows that a 4-in.-long flaw would be expected to pass a hydrostatic test to 90 % SMYS with a depth of 41 % wall thickness, but the largest surviving 4-in.-long flaw would only be 30 % wall thickness if tested to 100 % SMYS.

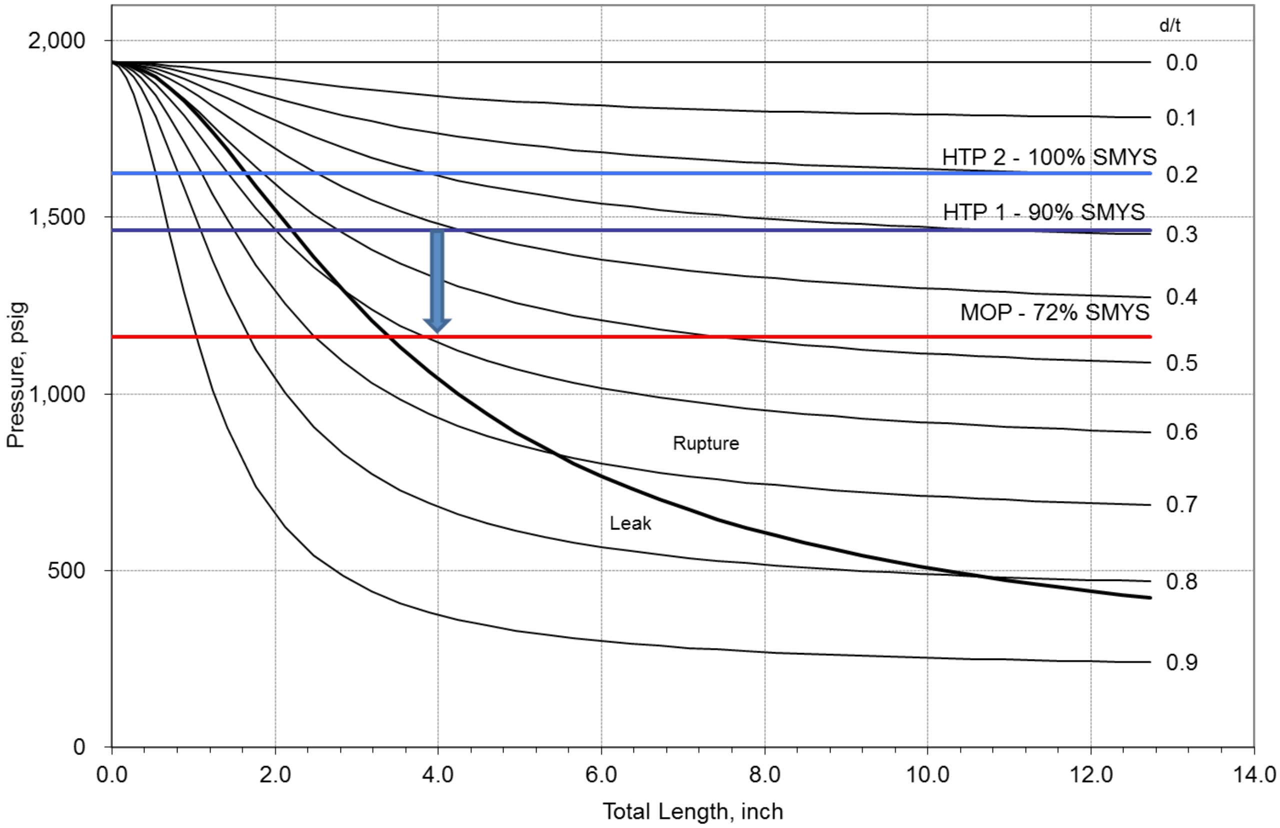

Figure 7—Failure Pressure vs. Flaw Size for a 16 in. OD by 0.250 in. Grade X52 Pipeline with Blunt Flaws

In either case, the 4-in.-long flaw would have to grow (shown by the arrow in Figure 7) to a depth of ~59 % wall thickness to fail at operating pressure in a pipeline operated at 72 % SMYS. Given a constant growth rate of 0.0075 in. (3 %) per year[17], the test to 90 % SMYS would require reassessment in six years (additional 18 % wall thickness to failure), whereas the test to 100 % SMYS would not require reassessment for 9.7 years (additional 29 % wall thickness to failure).

The curves shown in Figure 7 are based on the modified Ln-secant equation[18], and are generated for a subject pipeline based on pipe attributes. This methodology is widely accepted within the pipeline industry and is based on the NG-18 surface flaw equation, developed in the 1960s at the Battelle Memorial Institute. Additional accepted and validated methods (e.g. ASME B31G, modified B31G, RSTRENG, modified Ln-Sec, CORLAS, PRCI MAT-8, API 579) exist to calculate failure pressures of axially oriented flaws. For lower-toughness materials, models such as Ln-Sec and CORLAS have limited applicability. It is the responsibility of the pipeline operator to select a model that is suitable for the application.

[17] A constant corrosion growth rate is an assumption for theoretical purposes only. Actual growth rates are subject to many variables, including cathodic protection, product temperature, corrosion depth, geometry, coating type, and coating condition.

[18] Kiefner, J.F. “Defect Assessment 1 – Modified Equation Aids Integrity Management,” *Oil and Gas Journal*, October 6, 2008, pages 78–82; and “Modified Ln-secant Equation Improves Failure Prediction,” Oil and Gas Journal, October 13, 2008, pages 64–66.

6.7.2.2 Deterministic Approaches

The simplest method in establishing an assessment interval is to use a deterministic approach. This involves making conservative assumptions for many or all the parameters in the analysis and developing a reassessment interval based on these conservative assumptions. This can lead to excessively conservative results.

6.7.2.3 Statistical Approach

If the simple deterministic approach yields a remaining life that is sufficiently long, or in excess of maximum test intervals allowed by regulation, most often the analysis is accepted. Refer to Section A.3.1 for a case study that demonstrates that effective factors of safety using the worst possible values for all input parameters can be high and could lead to frequent assessments. The effect is that options for management of the pipe's integrity are limited. Frequent testing produces large pressure cycles that can be detrimental to the pipeline's integrity. A statistical reliability approach is likely better suited when deterministic methods yield a remaining life that is unrealistically low or when input parameters for a deterministic approach cannot be confidently known (see the case study in Section A.3.3). See Section A.3.2 for an additional case study where a pipeline operator employs a statistical approach using a Monte Carlo analysis to develop a target reliability threshold with which to select the interval. While applicable to SCC, the methodology of using a distribution of values and the statistical method is sound for any set of input parameters.

6.7.3 Corrosion-caused Metal Loss

In addition to the detailed analysis described above, Table 5.6.1–1 of ASME B31.8S-2014 provides guidance in establishing assessment intervals for gas pipelines when using pressure testing for external or internal corrosion. Test intervals are based on the ratio of test pressure to operating pressure. For pipelines with operating pressures over 50 % SMYS, a maximum interval of 10 years is recommended. This is based on achieving a test pressure of 1.39 times the MAOP, which, for a pipeline operating at 72 % SMYS, corresponds to a test pressure equivalent to 100 % SMYS.

6.8 Cracking

6.8.1 General

The primary difference between calculating burst pressures for corrosion-caused metal loss and cracking is that failures of blunt flaws such as corrosion are controlled by the size of the flaw and the strength of the material, independent of toughness. For sharp flaws such as cracks, toughness is a key parameter.

6.8.2 Stress Corrosion Cracking

With an understanding of the SCC growth rate, the largest remaining flaw that could exist in the pipeline can be modeled using the methods described above, and a test interval can be readily determined.

Without a good understanding of the SCC growth rate, conservative estimates should be made. Many pipeline operators use a model based on the method described in ASME STP-PT-011 for determination of test intervals for SCC. The test intervals suggested by this reference are empirically based. For example, following a pressure test for SCC, based on conservative assumptions for unknown growth rate, the next pressure test is recommended within 3 to 6 years, with the shorter interval chosen if there were test failures. The second interval would equal the first, and following that test, based on the intervals of the successful test programs, the interval can be extended.

When SCC is managed using hydrostatic testing, test pressures over 100 % SMYS are typically recommended. Even if 100 % SMYS is not achievable (for example, where unintended vintage seam weld failures limit maximum test pressures), a lower test pressure will still provide benefit. Section A.3.2 presents a statistical approach that can be used to establish a test interval based on the highest test pressure levels achieved.

6.8.2.1 Longitudinal Seam Defects of ERW Pipe and Fatigue Analysis

Bond line and heat-affected zone (HAZ) toughness, critical parameters for evaluation of remaining strength of cracking flaws, is known to vary, even in a single joint of pipe. Even if representative pipe samples are available, this property cannot be reliably measured in the field.

Fatigue analysis is based on the evaluation of the pressure cycling or other mechanisms (e.g. thermal) in the pipeline that could promote anomaly growth. Liquid pipelines have a higher propensity for fatigue as the product transported is incompressible when compared with gas, and pressure cycles tend to be greater. Refer to API 579-1 and the *Pipeline Rules of Thumb* (8^{th} Edition, Chapter 21, Rehabilitation – Risk Evaluation) for a description of fatigue analysis. This can be completed once the expected range of imperfection sizes and the pressure history are known or can be reasonably estimated in the pipe of interest.

While lower-bound toughness values will yield a more conservative (e.g. lower) failure pressure of a feature of a certain size, an assumption of high toughness is more conservative for evaluation of crack growth due to fatigue, as remaining flaws are assumed to be larger after a test. Longer flaws in high-toughness material may survive a pressure test but will be more susceptible to fatigue during operation. Some operators use toughness values of 5 ft-lbs or less when pipe is known to have low-toughness seam welds and 25 ft-lbs when the actual value is not known. Operators should be cautious when choosing values for fatigue analysis, as remaining life may not be effectively characterized using nominal pipe properties. A statistical approach, if possible, may be more effective.

Refer to Section A.3.3 for a case study illustrating the importance of the assumed values in the fatigue analysis.

7 Potential Detrimental Effects of Hydrostatic Testing

7.1 General

Industry research and operational experiences over the past several decades have identified several potential detrimental effects of hydrostatic testing. While the benefits of hydrostatic testing have been well established, the detrimental effects are understood to a lesser extent, and as such, the severity and frequency of occurrence are not well known. Some detrimental effects of hydrostatic testing include, but are not limited to:

— developing leaks following the hydrostatic test (e.g. at lack-of-fusion (LOF) defects in ERW pipe);

— excessive yielding and plastic deformation of the line pipe resulting in expansions > 2 % could be detrimental to pipe properties;

— crack extension of subcritical cracks or other non-critical flaws to near failure during a hydrostatic test leading to pressure reversals (a failure at a pressure level lower than previously achieved);

— reduced fatigue life of just-surviving flaws due to crack extension as a result of large pressure cycles from repeated hydrostatic tests;

— activation of resident flaws; and

— increased threat of low-cycle fatigue crack growth due to testing of unrestrained mechanical damage within a dent, gouges, or deformations.

Except for the last bullet item above, these events are more likely to occur when testing to levels greater than previous hydrostatic tests and mill tests. Limiting the occurrence of each is managed through design of the test and consideration of the maximum stress levels and hold times, especially when using spike testing to manage fatigue cracking or SCC.

7.2 Effects of Stress Levels

TTO6 suggested spike test pressure levels equivalent to 100 % SMYS for pipelines operating at the upper limit, and then a linear relationship to recommend minimum spike hydrostatic test pressures for pipelines operating between 20 % and 72 % SMYS. TTO6 also states, "It is unrealistic to expect an operator to employ this equation to justify pressurizing a pipeline containing older ERW pipe to a pressure level exceeding the equivalent of 100 % of SMYS."

An explanation requires a basic understanding of material properties, manufacturing process, and mill pressure testing. For instance, low-frequency ERW pipe contains a higher number of mill imperfections and flaws characteristic of the manufacturing process relative to modern line pipe. Modern line pipe also generally exhibits higher fracture toughness properties when compared with legacy line pipe materials, and the typically lower fracture toughness of the legacy materials results in decreased ability for the material to strain around flaws. Failures can thus initiate at relatively small flaws in low-toughness materials compared with a higher-toughness material. Finally, the mill test pressures for legacy pipeline steels were generally on the order of 60 % to 85 % SMYS, increasing the likelihood that legacy pipe materials likely contain resident seam flaws that may fail during a test exceeding historical levels, but that would not have otherwise been considered an integrity threat.

Operators should consider all the benefits and potential detrimental effects when planning for hydrostatic testing on legacy pipelines to stress levels that approach 100 % SMYS.

Consideration should be given to decreasing the frequency of hydrostatic testing whenever possible to reduce the likelihood of these conditions occurring. An extended interval that is technically justified would reduce the potential damage to seam flaws as a result of high-pressure tests. Refer to the case study summarized in Section A.3.1 regarding the effective factors of safety that can lead to frequent testing but may not be warranted.

7.3 Effects of Hold Time

A review of references and pipeline operator practices identified a wide variation of spike test hold times ranging from 10 minutes to one hour, and no reference recommended a hold time of longer than one hour. Research conducted at Battelle and documented in NG-18 Report 111[19] and AGA NG-18 Report 194 demonstrated that extended hold times can cause flaws to grow to failure that otherwise would not have grown and survived a test, and that hold times at maximum pressure should be minimized.

The highest test pressures attained are the critical parameters in quantifying the benefits (limiting remaining flaw size and maximizing the test interval) of the test. If the test is held at a higher pressure for a longer duration, the likelihood of failure during the test is increased; no additional benefit is realized through any of the models, which either limits the size of remaining flaws or extends test intervals.

The case study in A.4.3 supports the assertion that shorter test durations are beneficial in limiting detrimental effects. In this case study, an operator administering a hydrostatic test program for SCC historically used an 8-hour hydrostatic test duration above 100 % SMYS, during which failures were observed. More recently, higher pressures have been attained on separate occasions using a 15-minute spike test as part of the test program.

7.4 Short-Term and Long-Term Implications

Following a successful test program, defined as achieving the test plan objectives, the integrity of the pipeline at operating pressure is demonstrated for some defined period. Based on the pipe properties and test pressures achieved, the depth and length of just-surviving flaws can be estimated. Depending on the mechanisms for time-dependent flaw growth, and considering an appropriate safety factor, the reassessment interval can be established in consideration of an appropriate safety factor. In-service failures are unexpected immediately following a hydrostatic test unless the deterioration rate was greatly underestimated.

[19] Kiefner, J.F., Maxey, W.A., and Eiber, R.J. "A Study of the Causes of Failures of Defects That Have Survived a Prior Hydrostatic Test," NG-18 Report 111, November 3, 1980.

Section A.4.2 summarizes a case where a pipeline experienced an in-service leak following 52 years of operation and seven hydrostatic tests. The case study is inconclusive regarding whether the leak was due to the repeated hydrostatic testing, but anecdotally, pipeline operators have reported experiencing leaks following completion of hydrostatic tests. Many gas operators will conduct an aboveground leak test (e.g. flame ionization survey) upon return to service after completion of a hydrostatic test.

The presence of a leak following a hydrostatic test would not invalidate the test as it pertains to material strength because it is recognized that small, deep defects such as pits may survive hydrostatic tests but leak shortly afterwards due to continued defect depth growth. Such defects do not generally affect the strength of the pipeline system, although they may cause leaks.

8 Additional Considerations

8.1 General

Various industry references (including API 1110, ASME B31.4, ASME B31.8, and the INGAA Foundation's recently published white paper[20]) provide an overview of logistical issues that should be considered in planning and executing a pressure test. These include, but are not limited to, permitting, communications planning, documentation requirements, and testing in subzero conditions. These considerations are outside the scope of this technical report.

8.2 Role of Other Integrity Assessment Methods

8.2.1 General

Pipeline integrity is generally assessed using one of the following processes:

— pressure testing;

— ILI; and

— direct assessment.

These methods are not technically equivalent. Each has advantages, disadvantages, and operational concerns that should be considered. Various ILI technologies, with appropriate detection and sizing specifications, can detect and characterize metal loss, deformations, and cracks. ILI also provides details on the distribution of anomalies that could exist in the pipeline and may identify flaws that would otherwise pass a hydrostatic test.

Integrity assessments such as direct assessment and ILI are used to identify subcritical flaws that, if left unmitigated, have the potential to fail at some time in the future.

Pressure testing provides no information on the distribution or population of flaws that survive the test. Pressure testing provides an assessment covering a variety of threats compared with individual ILI technologies, and has one distinct advantage that, in some instances, becomes compelling. The advantage is that, in contrast to ILI or DA methods, hydrostatic testing does not rely on models, assumptions, or statistical estimates of material properties and behavior, nor does it assume similarities of coating condition, environment, and correlations between some measured value and system condition. In a pressure test, the entire structure, with all its real imperfections and actual properties, even as they vary throughout the structure, is tested with what is usually a clear result.

8.2.2 Using ILI to Quantify Detrimental Effects

The industry has considered the use of ILI that is performed just prior to and just after pressure testing to measure the extent of detrimental flaw growth that could occur during pressure testing. ILI is currently believed to be

[20] Jacobs Consultancy Inc., and Gas Transmission Systems Inc. *Technical, Operational, Practical, and Safety Considerations of Hydrostatic Pressure Testing Existing Pipelines*. December 5, 2013.

ineffective since the extent of flaw growth is likely below the measurement accuracy and reliability limits of the ILI technology.

8.2.3 Using Pressure Testing to Validate ILI Processes

Unlike a pressure test, which identifies anomalies only through destructive means, an ILI survey will provide a listing of anomalies by location. Pressure testing after an ILI inspection and after an excavation and repair program will confirm that defects of a given size or larger are no longer present.

A successful pressure test following an ILI can confirm that the analysis of the ILI data and selected response criteria are valid. It also validates the entire anomaly remediation process for a pipeline operator, including location of excavations, in-ditch NDE, and repair evaluation criteria. Section A.2.2 summarizes a case study of an application of hydrostatic testing for validation of ILI.

8.2.4 Data Integration with Other Assessments

The relationship of pressure testing to other integrity assessment methods is not limited to physical inspection methods. Integration of additional data, along with the successful completion of a hydrostatic test, is a valuable tool for establishing assumptions to calculate the deterioration rate and the re-inspection or reassessment interval. As stated earlier, hydrostatic testing as an assessment of a pipeline provides only a snapshot of the integrity of the pipeline on the day of the completion of the test. No information regarding coating condition or the actual population of flaws in the pipeline is gathered during pressure testing. If used as an assessment for corrosion or SCC, when combined with surveys used to monitor and evaluate coating or cathodic protection systems (e.g. CIS, ACVG, DCVG, or others), additional information can be obtained for use in performing an assessment of the pipeline.

When conducting hydrostatic testing, some pipeline operators utilize CIS or other surveys as an additional assessment tool for estimating the deterioration rate of the applicable time-dependent threats to help estimate the interval to the next integrity assessment.

Annex A
(informative)

Case Studies

A.1 General

The case studies utilized for this work reflect both the positive and negative aspects of hydrostatic test experiences as contributed in a candid and open manner by pipeline operator representatives specifically for this technical report. Though the case studies are organized into topic areas, as these are real-world examples rather than theoretical inventions used to illustrate a specific point, each will have applicability into more than one topic area. Each is presented as an example to illustrate a pipeline operator's response to considerations and real challenges when implementing hydrostatic test programs.

A.2 Development of Hydrostatic Test Program Objectives and Execution

A.2.1 Hydrostatic Testing as Part of Risk-balanced Hydrostatic Test Program

A.2.1.1 Case Study Value

This case study demonstrates a risk-based approach to the use of hydrostatic testing as an integrity management tool. Included are considerations for limiting test pressure to minimize potential adverse impacts while still achieving target program reliability goals.

A.2.1.2 Background

Table A.1 shows the pipe information and properties of the pipe tested in this case study.

Table A.1—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MOP psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
26	0.281	X52	Not reported	Crude oil	1954–1957	AO Smith	EFW

A.2.1.3 Discussion

A hydrostatic test was designed to illustrate a safety factor that aligned with the target reliability. The hydrostatic pressure test was engineered to achieve fitness-for-service goals, risk goals, and asset preservation goals.

To achieve these objectives, the pipeline operator developed and executed a plan in support of the following specific pipeline integrity goals:

— Establish a safety margin for the crack program to conclude that the pipe is not susceptible to crack rupture for a minimum of 10 years.

— Establish a crack program that targets the reliability at MOP.

— Minimize the environmental impact.

— Minimize the adverse customer impact and associated commercial impact.

The crack program safety and reliability goals are related to test pressure levels achieved during the test. The last two goals require additional consideration to limit the likelihood of test failures.

To minimize stable crack growth to non-injurious flaws and minimize the likelihood of initiating and propagating cracks from benign manufacturing flaws, the following conditions needed to exist:

— The exposure time at elevated stresses was minimized and aligned with industry best practices for spike testing and a 10-minute hold time.

— The test was segmented such that the pipe exposed to stresses exceeding historic proof stresses was minimized and the stress levels on the test did not exceed 100 % SMYS.

— Pressure cycling during the test was minimized. For example, pumping to maintain pressure during the test was used if volume loss could be accounted for and if the leak source was not a flaw that could destabilize (e.g. yielding of low-strength pipe).

There were no pipe body or longitudinal seam-related leaks during the test program. Additionally, the results from the hydrostatic test reliably defined the fitness for service, as follows:

— The achieved pressure for the short-duration, high-pressure test exceeded 1.25 times MOP, which established the safety factor for the crack program to conclude that a pipe is not susceptible to crack rupture for a minimum of 10 years.

— The pressure for the qualifying test established a safety factor of 1.25 times MOP, which was in relation to Subpart E of 49 CFR §195, establishing a crack program reliability for a rupture threat at MOP.

— The achieved pressures for the leak test established a minimum safety factor of 1.10 times MOP in relation to Subpart E of 49 CFR §195, establishing crack program reliability for a leak threat at MOP.

A.2.2 Hydrostatic Testing to Validate an ILI-Based Seam Weld Integrity Program

A.2.2.1 Case Study Value

A successful hydrostatic test program following an ILI program in this case study provided a validation of the effectiveness of the data analysis and integration of the ILI process. The test demonstrated that the ILI-based integrity program successfully located and repaired all critical defects that would have failed at less than 1.25 times MOP in the hydrostatic test section before the test.

A.2.2.2 Background

Following a 2007 in-service failure of a seam defect, the pipeline operator reviewed the crack-detection ILI program in place prior to the failure and concluded that a more effective ILI assessment tool was needed to assess the identified seam weld anomaly issue. The pipeline operator developed an ILI inspection program with a transverse flux MFL tool and used an enhanced data analysis protocol (developed internally). The enhanced ILI data analysis resulted in numerous sites selected for field investigation. All sites selected were excavated, assessed using NDE, and repaired as necessary. Once the ILI program was complete, hydrostatic testing was utilized on a representative portion of the pipeline system as a validation for the ILI process.

Table A.2 shows the pipe information and properties of the pipe tested in this case study. Table A.3 shows the hydrostatic test history of the pipe.

Table A.2—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MOP psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
20	0.344	X52	1098 (61.4 %)	Crude oil	1952	Kaiser	SSAW

Table A.3—Hydrostatic Test History

Date	Event	Stress Level (Test Pressure)
1952	Fabrication mill test	85 % SMYS [a]
1975	Hydrostatic test	76.1 % SMYS (1362 psig) [b]
1992	Hydrostatic test	76.7 % SMYS (1372 psig) [b]
2009	Hydrostatic test	85.3 % SMYS (1526 psig) [b] (1 test failure above 1.25 x MOP)

[a] Assumed based on requirements within API 5L/5LX as of the year of installation.
[b] Test parameters at monitoring location (upstream pump station discharge).

A.2.2.3 Discussion

In this scenario, the successful hydrostatic test on a representative section of pipeline was to be used to demonstrate effective application of the ILI program to manage seam weld integrity. The regulator required that the hydrostatic test program include a spike test to a level of 1.39 times the MOP of the test section.

The hydrostatic test program, as summarized in Table A.4, was conducted on an 8.1-mile segment in the same pipeline section where the 2007 in-service failure occurred. The test segment was also selected based on the density and severity of seam weld defects found during the field investigations.

Table A.4—Hydrostatic Test Plan Summary

Sequence	Description	Stress Level SMYS (psig)	Hold Time
1	Pressurize and hold at 60 % of MOP for temperature stabilization	36.9 % (660)	4 hours minimum
2	Increase pressure to spike test target level	85.3 % (1526)	10 minutes
3	Decrease pressure and hold for qualifying test at 1.26 times MOP	77.6 % (1388)	4 hours
4	Decrease pressure and hold for leak test at 1.1 times MOP	67.5 % (1208)	4 hours

NOTE 1 All pressures are from the monitoring location (upstream station discharge).

NOTE 2 Qualifying test pressure target was 1373 psig plus 15 psig margin to allow for small pressure decay.

NOTE 3 Maximum spike test pressure of 89.7 % SMYS (1605 psig) occurred at the low point of the test segment.

During the first attempt of the test program, while increasing pressure to the spike test target, a seam weld failure occurred 7.33 miles downstream of the upstream pump station. The hydrostatic test failure pressure was 1.26 times the MAOP or 1390 psig (77.7 % SMYS).

Following repair of the pipeline at the site of the hydrostatic test failure, a second attempt was made to conduct the spike hydrostatic test on the same test section. The test was completed successfully per the program parameters.

The pipe section that failed during the hydrostatic test was removed and subjected to a metallurgical failure analysis that concluded the test failure occurred at a pre-existing incomplete fusion seam weld defect. The defect was approximately 20.9 in. long, had a maximum depth of 43.5 % of the wall thickness, and terminated at the downstream end of the pipe joint. A weld area crack was also present at the downstream end of the defect and terminated in the girth weld. The weld area crack was approximately 1 in. long and had a maximum depth of 94.2 % of the wall thickness. It was believed that the weld area crack had been enlarged from a prior maximum depth of 43.5 % to a maximum depth of 94.2 % from a prior load excursion. There was no evidence of fatigue growth in the defect that failed during the hydrostatic test.

Two observations are noted in this case study, even though a test failure occurred following the ILI program:

— The test pressure was the highest pressure ever experienced on the line segment at that time, which supports the likelihood that the defect was introduced at the time of pipe manufacture. It also supports the finding that the defect was not growing due to fatigue and had likely passed prior hydrostatic tests on the pipeline segment.

— The pressure level at the time of the hydrostatic test failure was greater than 1.25 times the MOP, thus providing confidence that the ILI program would effectively identify defects that could fail below this level on this pipeline.

A.2.3 Sequence of a Test Program—Spike Testing Following Qualification Testing

A.2.3.1 Case Study Value

In this case study, due to logistical considerations, the spike test was performed at the end of the hydrostatic test cycle, and a leak test was performed following return to pressure service. From a technical standpoint, while not typical, the alternative sequence does not affect the effectiveness of the test in mitigation of the rupture risk at normal operating pressure. This should only be done after consideration for an increased possibility of leaks (considering public safety or environmental effects) following the test.

A.2.3.2 Background

In May 2009, the pipeline experienced an in-service failure. A hydrostatic test with a spike test was performed following the incident. The pipeline experienced 11 test failures at pressures between 870 psig and 1450 psig. Table A.5 shows the pipe information and properties of the pipe tested in this case study.

Table A.6 shows the hydrostatic test history of the pipe.

Table A.5—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MAOP Psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
18	0.250	X52	866 (60 %)	Natural gas	1959	Youngstown Sheet and Tube	DC ERW

Table A.6—Hydrostatic Test History

Date	Event	Stress Level
1959	Fabrication mill test	85 % SMYS [a]
1970	Hydrostatic test	Unknown
2/28/2011	Hydrostatic test	SCC test failure at 60.25 % SMYS (870 psig)
3/2/2011	Hydrostatic test	Seam weld LOF test failure at 69.60 % SMYS (1005 psig)

Date	Event	Stress Level
3/4/2011	Hydrostatic test	SCC test failure at 79.29 % SMYS (1145 psig)
3/5/2011	Hydrostatic test	SCC test failure at 83.80 % SMYS (1210 psig)
3/7/2011	Hydrostatic test	SCC test failure at 84.49 % SMYS (1220 psig)
3/2011	Hydrostatic test	83.08 % SMYS (1200 psig) Line returned to service at restricted pressure (682 psig/47 % SMYS)
10/27/2011	Hydrostatic test	SCC test failure at 94.88 % SMYS (1370 psig)
11/1/2011	Hydrostatic test	SCC test failure at 95.22 % SMYS (1375 psig)
11/3/2011	Hydrostatic test	SCC test failure at 100.42 % SMYS (1451 psig) Test interval set to 3 years
11/10/2014	Hydrostatic test	SCC test failure at 89.40 % SMYS (1291 psig) Test interval set to 3 years

[a] Assumed based on requirements within API 5L/5LX as of the year of installation.

A.2.3.3 Discussion

The pipeline exists in an urban area near a major international airport, with one of the failures occurring under a runway. Due to restrictions accessing the site, the requirement to close major roads during the test, and public safety considerations near a major transportation hub and the number of test failures being experienced, the 8-hour, 49 CFR §192 Subpart J-compliant part of the test was performed prior to the spike portion of the test. The pipeline operator performed the leak test through a flame ionization survey following return to service.

When using a spike test, the pressure integrity of the pipe is proven during the spike period and the remainder of the test (typically a qualification test per applicable regulation) is for the purpose of identifying any leaks that could have gone undetected during the strength test. In this case, the operator did not have that option, and performed the leak test through alternative means upon returning to service.

A.3 Hydrostatic Test Intervals and Safety Factors

A.3.1 Effects of Compounding Safety Factors and Conservatism on a Seam Integrity Program

A.3.1.1 Case Study Value

This case study involves a pipeline that is subject to a hydrostatic test program to manage seam cracking and fatigue threats. The pipeline has been tested to failure (18 failures over multiple test programs); no evidence of fatigue has been identified. Fatigue modeling of the defects that failed during the test, using actual operational pressure cycle data and compounded factors of safety, predicts failure. This case study demonstrates that excessive factors of safety limit an operator's ability to manage cracking threats and may lead to high testing frequencies that do not improve integrity and may be detrimental to the overall health of the pipeline.

A.3.1.2 Background

None of the 18 test failures experienced during the 2009 and 2013 pressure tests exhibited evidence of features that had extended in service. No in-service failures have occurred on this line segment.

Additional analysis was performed on the second feature (OD hook crack) shown in Table A.9. This defect was subjected to a metallurgical failure analysis and material property testing and was determined to be 4 in. long by 0.100 in. deep.

Based on the defect dimensions established through the metallurgical examination and the pipe properties determined through subsequent testing, a pressure cycle fatigue analysis (PCFA) was performed. One year of actual operating pressure cycles experienced at the failed pipe joint was used as a basis for modeling the fatigue life. The calculated time to failure was 41.9 years at an operating pressure of 1084 psig, with a final depth at failure projected to be 0.182 in. (72.6 %). If modeled at MOP, the calculated time to failure was 34 years, with a final projected depth of 0.149 in. (59.4 %).

Table A.7 shows the pipe information and properties of the pipe tested in this case study. Table A.8 shows the hydrostatic test history of the pipe.

Table A.9 summarizes the 2013 pressure test failures.

Table A.7—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MOP psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
12.75	0.250	X52	1440 (70.6 %)	Propane (HVL)	1961	Lone Star Steel	LF-ERW

Table A.8—Hydrostatic Test History

Date	Event	Stress Level
1961	Fabrication mill test	85 % SMYS [a]
1961	Construction hydrostatic test	78.5 % SMYS
2004	Hydrostatic test	85 %–90 % SMYS test range (no test failures were experienced)
2009	Hydrostatic test	90 % SMYS minimum (12 test failures, all at or above 2004 levels)
2013	Hydrostatic test	90 % SMYS minimum (6 test failures, all at or above 2004 levels)

[a] Assumed based on requirements within API 5L/5LX as of the year of installation.

Table A.9—2013 Pressure Test Failure Summary

2013 Test Failure Defect	2004 Stress Level* SMYS (psig)	2009 Stress Level[1] SMYS (psig)	2013 Stress Level[1] SMYS (psig)	Variance (2013−2009) SMYS (psig)
ID hook crack and stitched weld	87.9 % (1793)	95.2 % (1942)	95.28 % (1943)	+0.1 % (1)
OD hook crack	88.2 % (1799)	95.6 % (1949)	94.94 % (1936)	−0.7 % (13) [2]
Interacting OD and ID hook cracks	89.9 % (1834)	94.9 % (1935)	95.04 % (1938)	+0.1 % (3)
Interacting OD and ID hook cracks	88.0 % (1795)	93.0 % (1896)	95.87 % (1955)	+2.9 % (59)
ID hook crack and stitched weld	90.0 % (1844)	96.4 % (1965)	96.46 % (1967)	+0.1 % (2)
OD hook crack and stitched weld	88.2 % (1798)	94.0 % (1917)	96.51 % (1968)	+2.5 % (51)

NOTE 1 At the location of the 2013 test failure.

NOTE 2 Pressure reversal.

A.3.1.3 Discussion

Based on the fatigue analysis, this defect should have failed by fatigue growth within the 52 years of in-service operation or during one of the several pressure tests performed. However, it did not. Further, no fatigue failures have been experienced on this pipeline segment, nor has evidence of fatigue been identified. This suggests that the various conservative parameters utilized in the fatigue model have a compounding effect (refer to Table A.10). One would suspect some evidence of fatigue growth in the 18 previous test failures if fatigue were an active threat on the pipeline. Conservative assumptions relied upon for fatigue life estimates suggest that the known flaws that pre-existed in the pipeline should have failed in service but did not. Various conservative factors of safety appear to explain the no-growth of the flaws during operation.

Table A.10—Fatigue Life Parameters

Fatigue Life Parameters	Value
The API 579 crack rate of C = 8.61E-19 vs. other published work, such as C = 3.6E-19	2.40 x
The crack growth rates are based on $\mu \pm 2\sigma$, which provides that 97.5 % confidence level that the fatigue life will be longer. The PRCI [a] report suggests the difference from μ to $\mu \pm 2\sigma$ being a factor in the range of 1.5.	1.5 x
Using the lower bound crack length $\sqrt{(Dt)}$ vs $2\sqrt{(Dt)}$ (1.8 in. vs 3.6 in.) [b]	1.54 x
Using pressure spectrum just downstream of pump station and applying to entire section	2.11 x
Total:	**11.77 x**
Additional FOS:	**2.00 x**
	23.35 x

[a] Dinovitzer, A. *Improved Method for Estimating Remaining Fatigue Life of ERW Pipelines*, PRCI RR-214-104505

[b] Experience suggests that the lengths of fatigue cracks that have caused failures range from about $\sqrt{(Dt)}$ to $4\sqrt{(Dt)}$. The most common size associated with past ERW seam fatigue ruptures seems to be $>2\sqrt{(Dt)}$.

Based on the demonstrated effect of compounding the safety factors, the pipeline operator developed the following recommendations:

— Consideration should be given to decreasing the frequency of hydrostatic testing when it can be demonstrated that the threat of cyclic fatigue to the longitudinal seams is low. A longer interval would reduce the potential damage to seam flaws as a result of high stress levels and subsequent pressure reversals that have occurred over the years.

— Excessive factors of safety do not improve integrity and limit an operator's ability to best understand and manage cracking threats.

— When comprehensive, highly-detailed information about seam properties is known, consideration should be given to reducing the additive factors of safety associated with failure life prediction.

PRCI has completed research in improved methods for estimating remaining fatigue life of ERW pipelines. This research has better defined crack growth parameters to be utilized in crack growth models. Table A.11 summarizes fatigue growth rate parameters for pipeline materials.

Table A.11—Fatigue Growth Rate Parameters for Pipeline Materials

R-Ratio	Mean		Mean + 2σ		Δ
	C	m	C	m	
R <0.5	2.05401E-20	3.25	3.08814E-20	3.25	1.50
R >0.5	7.83577E-19	2.90	1.15803E-18	2.90	1.48

R-Ratio	Mean		Mean + 2σ		Δ
	C	m	C	m	
Combined	6.30290E-19	2.91	1.04601E-18	2.91	1.66
Where: da/dN = in/cycle ΔK = psi $in^{0.5}$					

A.3.2 Statistical Approach to Establish a Hydrostatic Test Interval for SCC

A.3.2.1 Case Study Value

A statistical engineering approach was used to establish a hydrostatic test interval using a reliability target based on the ratio of operating pressure to test pressure. A useful level of reliability can be achieved when test pressures are limited by the presence of resident mill defects.

A.3.2.2 Background

The pipeline was subject to a pressure test program to over 90 % of SMYS in March and April 2014. During this pressure testing program, one leak and four ruptures occurred. The direct cause of the leak was determined to be near neutral pH SCC. The direct causes of the four ruptures were resident manufacturing defects in the longitudinal seam, including LOF defects and a hook crack. The failure pressures for each were above 90 % and below 93 % of SMYS.

Table A.12 shows the pipe information and properties of the pipe tested in this case study. Table A.13 shows the hydrostatic test history of the pipe.

Table A.12—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MAOP psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
8.625	0.188	Grade B	915 (60 %)	Natural gas	1958	Jones and Laughlin	LFERW

Table A.13—Hydrostatic Test History

Date	Event	Stress Level
1958	Fabrication mill test	60 % SMYS [a]
2014	Hydrostatic test (multiple test failures)	90 % SMYS (1373 psig) to 93 % SMYS (1419 psig)
2014	Hydrostatic test	90.8 % SMYS (1385 psig)
[a] Assumed based on requirements within API 5L/5LX as of the year of installation.		

A.3.2.3 Discussion

Consistent with accepted industry guidelines for use of hydrostatic testing for management of SCC, the original target test pressures were above 100 % SMYS, but after experiencing test failures of non-target defects, the pressures were reduced to 90.8 % SMYS in order to complete the hydrostatic test program. The 2014 hydrostatic test program subjected the pipe to historical maximum stress levels and was sufficient to ensure any remaining resident flaws would be inactive unless acted upon by other threats (e.g. test pressure levels exceeded 1.5 times MAOP[21]). The target pressure test levels for the mitigation of the SCC threat (> 100 % SMYS) were not reached.

The specific pipeline operator's internal procedures, consistent with industry guidance[22], utilize the empirical method described within Section 6.8 of this report to prescribe three years as a first reassessment interval for when the SCC growth rate is not well quantified. The three-year reassessment interval assumes the pipeline is tested to a minimum of 100 % of SMYS and operates at 72 % of SMYS. In this case, the target test pressures were not reached, and the pipeline was tested to just over 90 % SMYS, but it also operates at a stress level of 60 % SMYS.

Critical crack depths were calculated using the modified part through wall NG-18 (modified Ln-Secant[23]) equation for short and long cracks of 2 in. and 10 in., respectively, to represent geometries for both leak and rupture defects.

The modified Ln-Sec methodology was used to generate two critical crack depth versus length distribution functions for each of four stress levels:

— 60 % SMYS;

— 72 % SMYS;

— 90 % SMYS; and

— 100 % SMYS.

Using distribution functions for the crack geometries and SCC growth rates (expressed by the mean and standard deviation values), a Monte Carlo analysis was performed to determine remaining-life mean and standard deviations. The theoretical probability of a flaw growing to critical size within the first three years was then calculated assuming an operating pressure of 72 % SMYS and a successful pressure test to 100 % SMYS. This theoretical probability of failure was then used as the target reliability level to establish the reassessment interval.

Using alternate crack geometries, given by the different family of cracks that could survive a test to 90.8 % SMYS versus 100 %, a similar Monte Carlo analysis was performed to calculate the remaining-life mean and standard deviations for an operating pressure of 60 % SMYS. At an equivalent cumulative probability of failure, the required reassessment was shown to exceed the three years even though the target test pressures for SCC were not achieved.

A.3.3 Importance of Input Variables for Test Interval Determination

A.3.3.1 Case Study Value

This case study demonstrates the importance of assumed values input into PCFA. The family of just-surviving flaws is not characterized using nominal pipe properties, and conservatism is achieved with higher toughness values.

[21] ASME B31.4 and B31.8 each prescribe a test pressure of 1.25 times MOP or MAOP for assessment of manufacturing defects.

[22] Fessler, R.R., Batte, A.D., and Hereth, M. “Integrity Management of SCC in High Consequence Areas,” *ASME Report STP-PT-011*, Appendix E, page 75.

[23] Kiefner, J.F. “Defect Assessment 1—Modified Equation Aids Integrity Management,” *Oil and Gas Journal*, Oct 6, 2008 page 78–82; and “Modified Ln-secant Equation Improves Failure Prediction,” *Oil and Gas Journal*, Oct 13, 2008, pages 64–66.

A.3.3.2 Background

Hydrostatic tests were performed in 1982 and 2005 to pressures that correspond to 90 % SMYS. Spike testing was attempted in 2005, with the highest pressures attained over 95 % SMYS. However, the test pressure targets were revised, and after test failures were experienced in the test program, an approximate 3.8 % pressure reversal was experienced.

A metallurgical evaluation of the two failures experienced during the 2005 hydrostatic test program showed no evidence of fatigue growth at either of the test failures. A PCFA was performed following the successful 2005 pressure test and a minimum fatigue life was calculated to be 9.2 years. The reassessment interval was set to 4.6 years to provide a factor of safety equal to 2.0.

In 2008, approximately three years after the 2005 pressure test, the pipeline experienced an in-service leak and subsequent rupture at a seam-weld notch-like flaw, which grew by fatigue. The pipeline leaked for more than 24 hours prior to rupture. Metallurgical analysis concluded that the crack likely initiated or was enlarged due to previous hydrostatic testing, and it was probable that the final crack extension was due to in-service pressure cycle fatigue crack growth.

Table A.14 shows the pipe information and properties of the pipe tested in this case study. Table A.15 shows the hydrostatic test history of the pipe.

Table A.14—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MOP psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
12.75	0.250	X45	1255 (71 %)	Crude oil	1948	AO Smith	EFW

Table A.15—Hydrostatic Test History

Date	Event	Stress Level
1948	Fabrication mill test	85.0 % SMYS (1500 psig) [a]
1982	Pressure test	90.8 % SMYS (1602 psig)
2005	Attempted spike test	95.5 % SMYS (1685 psig)
2005	Attempted spike test	91.7 % SMYS (1618 psig)
2005	Pressure test	90.8 % SMYS (1602 psig)
2008	In-service leak/rupture	62.0 % SMYS (1094 psig)

[a] Assumed based on requirements within API 5L/5LX as of the year of installation.

A.3.4 Discussion

For this case study, the defect that failed in 2008 survived 60 years of operation and was subjected to at least five hydrostatic tests. The failure of the pipeline that occurred less than three years following the 2005 pressure test indicates the defect had a high resistance to the failure due to strength and fracture toughness. Once the crack was activated, the time to failure was short. The PCFA was performed using values believed to be conservative and a 100 % safety factor applied; the PCFA was unable to accurately predict the remaining life of the pipeline using nominal pipe properties.

Following the failure, the metallurgical examination of the failure noted that the full-size Charpy equivalent upper-shelf energy of the weld metal was 33 ft-lb and the actual yield strength was 67,500 psi. Both values are higher than the nominal pipe property values that were used for the PCFA. This illustrates the importance of choice of input variables for the PCFA.

A.4 Detrimental Effects of Hydrostatic Testing

A.4.1 Hydrostatic Test Failures above Mill Test Pressure Levels

A.4.1.1 Case Study Value

This case study involves a pipeline that was subject to a hydrostatic test for a seam assessment. Four test failures were experienced at levels just above the levels prescribed by API 5LX for the mill test pressure. This demonstrated that failures may result when hydrostatically testing pipelines manufactured with legacy methods to levels that exceed the mill test pressure. A pressure reversal of approximately 5.4 % was also experienced between the third and fourth test failures. A pressure reversal of this magnitude is rare, but not unknown.

A.4.1.2 Background

In 2000, a hydrostatic test program was completed on an approximately 44-mile length section of pipeline, and four test failures were experienced. All four failures initiated and propagated in the ERW longitudinal weld seam.

Table A.16 shows the pipe information and properties of the pipe tested in this case study. Table A.17 shows the hydrostatic test history of the pipe. Table A.18 summarizes the failure history.

Table A.16—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MAOP psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
8.625	0.322	X42	2258 (72 %)	Refined products	1952	Unknown	ERW

Table A.17—Hydrostatic Test History

Date	Event	Stress Level
1952	Fabrication mill test	75 % SMYS [a]
2000	Hydrostatic test	Four failures occurred (see Table A.18)
[a] Assumed based on requirements within API 5L/5LX as of the year of installation.		

Table A.18—Summary of Failure History

Failure No.	Failure Defect	Stress Level at the Location of the Failure
1	ID hook crack	77.4 % SMYS (2426 psig)
2	Cold weld	77.0 % SMYS (2415 psig)
3	Cold weld	81 % SMYS (2541 psig)
4	Cold weld	76.6 % SMYS (2403 psig)

A.4.1.3 Discussion

All the test failures occurred in the ERW seam of the pipe, and each appeared to have been caused solely by manufacturing defects in the seam. Failures 1 and 2 were on the first test section and failures 3 and 4 were on the second test section.

Failure 1 initiated at an ID hook crack adjacent to the ERW seam. The three other failures occurred in a series of cold weld defects that occurred in areas of stitching in the ERW seam. In each case, an independent evaluation of the failures identified no evidence of fatigue, corrosion, or environmental cracking.

The failures occurred at a pressure corresponding to a hoop stress of just above 75 % SMYS, which corresponds to the mill test pressure that the pipe would have experienced based on the API 5LX minimum mill test requirements in effect at the time. The test performed in 2000 was likely the maximum pressure the pipeline had experienced since the mill hydrostatic test, and any further testing conducted to this level may result in additional test failures.

The hydrostatic testing program clearly demonstrated that the surviving pipe material was at least as good as the pipe sections that failed during the test. The initial test targets were not achieved, and in this case, the pipeline operator chose to lower the operating pressure of the pipeline to a level that could be substantiated by the test pressures achieved.

A.4.2 In-service Leak Following Multiple Hydrostatic Tests

A.4.2.1 Case Study Value

Repeated use of hydrostatic testing on pipelines with populations of LOF or stitching defects, though effective at identifying critical-sized defects that could rupture in service, may alternatively lead to leaks of stable short, deep flaws after a hydrostatic test. In this regard, hydrostatic testing may have a negative effect.

A.4.2.2 Background

The pipeline at the failure location typically operates at 250 psig (13.9 % SMYS) to 600 psig (33.3 % SMYS). This pipeline segment was tested repeatedly by the pipeline operator for management of seam weld integrity with the last test following a failure (rupture) experienced on the pipeline in 2008. The pipeline has experienced seam weld failures during previous hydrostatic test programs, with three failures occurring in 2009, all of which were due to hook cracks in the seam weld.

Table A.19 shows the pipe information and properties of the pipe tested in this case study. Table A.20 shows the hydrostatic test history of the pipe.

Table A.19—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MAOP psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
12.75	0.250	X46	1219 (67.6 %)	Refined products	1958	Unknown	LFERW

Table A.20—Hydrostatic Test History

Date	Event	Stress Level
1958	Fabrication mill test	85 % SMYS [a]
1958	Construction hydrostatic test	Unknown
1972	Hydrostatic test	Unknown
1974	Hydrostatic test	Unknown
1987	Hydrostatic test	Unknown
1995	Hydrostatic test	Unknown
1999	Hydrostatic test	Unknown
2004	Hydrostatic test	Unknown
2008	In service failure	Unknown
2009	Hydrostatic test	83.9 % SMYS [b] 3 hook crack failures experienced

Date	Event	Stress Level
2010	In-service leak	20.6 % SMYS

[a] Assumed based on requirements within API 5L/5LX as of the year of installation.
[b] At the location of the 2009 hydrostatic test failure.

A.4.2.3 Discussion

Metallurgical investigation of the 2010 in-service leak identified that the direct cause of failure was an LOF defect in the longitudinal seam weld from original manufacture. The original construction defect survived the fabrication mill test, seven subsequent hydrostatic tests, and 52 years of operation prior to failure. There was no evidence of fatigue, corrosion, or time-dependent growth. It was noted in the metallurgical report that a possible cause was dissolution of a solid oxide film with the LOF defect.

There are numerous cases across the pipeline industry, including this case study, where similar LOF defects have experienced leakage following hydrostatic testing. The role of hydrostatic testing in dissolution of the oxide has not been validated, but it seems reasonable that repeated hydrostatic testing may have contributed to the deterioration of the oxide film within the defect.

A.4.3 Limiting Test Failures with Short Spike Test Duration

A.4.3.1 Case Study Value

This case study demonstrates both pressure test failures during spike testing over 100 % SMYS and the likelihood of experiencing test failures. Multiple test failures occurred during the 1992 test program at a lower pressure than has been obtained in two of the most recent hydrostatic tests. The recent hydrostatic test programs involve a short spike test duration of 15 minutes, whereas the 1992 test held the pipeline above 100 % SMYS for the full 8-hour test. The lack of recent test failures suggests two possible conclusions:

— The test program in 1992 removed critical-sized SCC defects and the remaining flaws are sufficiently small that test failures are not occurring at current test levels; or

— Growth to failure of subcritical defects is limited to some degree by the shortness of the test.

A.4.3.2 Background

In 2010, category 1[24] SCC was identified on the pipeline with a predicted failure pressure greater than 110 % SMYS. The operator expanded the excavation and the 2010 test program was performed on a 900-ft section of pipeline containing SCC. No test failures were experienced. Following the successful test program, the operator additionally removed four joints that contained the most significant SCC for full-scale burst testing. The joints failed at the following pressures:

— 1770 psig (160 % MAOP, 136 % SMYS);

— 1975 psig (180 % MAOP, 152 % SMYS);

— 1890 psig (170 % MAOP, 145 % SMYS);

— 1690 psig (150 % MAOP, 130 % SMYS).

[24] Definition of Category 1 SCC: A failure pressure greater or equal to 110 % of the product of the MOP and a company safety factor (typically equaling 110 % of SMYS).

Table A.21 shows the pipe information and properties of the pipe tested in this case study.

Table A.22 shows the hydrostatic test history of the pipe.

Table A.21—Pipe Information and Properties

Diameter (in.)	WT (in.)	Grade	MAOP psig (SMYS)	Product Type	Install Year	Manufacturer	Seam Type
30	0.375	X52	1100 (84.6 %)	Natural gas	1952	Unknown	N/A

Table A.22—Hydrostatic Test History

Date	Event	Stress Level
1952	Fabrication mill test	85 % SMYS [a]
1986	Hydrostatic test	106 % SMYS for 8 hours (no test failures)
1992	Hydrostatic test	108 % SMYS at the failure location (SCC failure during pressurization)
1992	Hydrostatic test	108 % SMYS at the failure location (SCC failure 6 minutes into the test)
1992	Hydrostatic test	108 % SMYS at the failure location (SCC failure 7 hours and 10 minutes into test)
1992	Hydrostatic test	106 % SMYS (no test failures)
1998	Hydrostatic test	> 100 % SMYS, actual pressure unknown (no test failures)
2005	Hydrostatic test	110 % SMYS for 15 minutes, 100 % SMYS for 8 hours (no test failures)
2010	Hydrostatic test	110 % SMYS for 15 minutes, 100 % SMYS for 8 hours (no test failures)
[a] Assumed based on requirements within API 5L/5LX as of the year of installation.		

A.4.3.3 Discussion

The results of the 2010 spike test and full-scale pressure tests validated the reassessment intervals used for the line segment. In accordance with guidance in ASME B31.8 for hydrostatic reassessment intervals for SCC, the pipeline segment is scheduled for hydrostatic reassessment in 2018. As part of the comprehensive SCC IMP program, the operator conducts magnetic particle inspection at all ILI anomaly bell-hole excavations with disbonded coating, external corrosion, or mechanical damage. Scheduled high-resolution MFL and high-resolution caliper ILI tools are also run on the line segment.

Annex B
(informative)

Additional Resources

B.1 General

As part of this work, a literature review was conducted by the project team to review the wide variety of industry references that present information on hydrostatic testing. Many of these are in alignment with this work but were not specifically cited. The section below is included here to provide a collection of useful resources for additional reading or reference. Each is referenced with a short summary of the information contained therein. It should be noted that the list of resources included below is intended to be as comprehensive as possible; if something is not shown, that does not necessarily indicate that it was disapproved or rejected.

B.2 Management of SCC and Environmental Cracking

— Fessler, Raymond R. and Rapp, Steve. *Method for Establishing Hydrostatic Re-Test Intervals for Pipelines with Stress-Corrosion Cracking*. Calgary, Alberta: s.n., 2006. IPC2006–10163.

Method for establishing hydrostatic reassessment intervals for pipelines with stress corrosion cracking. This is a conservative methodology that is widely used and accepted with industry and also recognized within ASME B31.8S.

— Rapp, Steve C., Marr, Jim E. *Field Experience with a Model for Determining Hydrostatic Re-Test Intervals*. Calgary, Alberta: ASME, 2012. IPC2012–90445.

Evaluates Fessler model with respect to collinear SCC features.

— Leis, B.N., Kurth, R.E. "Hydrotest Parameters to Help Control High-pH SCC on Gas Transmission Pipelines," *PRCI Report L51865e*, 1999.

Discusses test pressure levels required for effective management of SCC and also develops a probabilistic method for establishing hydrostatic test intervals for managing SCC.

— Batte, A D, et al. *Managing the Threat of SCC in Gas Transmission Pipelines*. Calgary, Alberta: s.n., 2012. IPC2012–90231.

Discusses reassessment intervals and the actual operator experience with their particular philosophy for SCC hydrostatic testing on gas pipelines.

— Chen, Weixing and Sutherby, Robert. *Laboratory Simulation of Hydrostatic Test in Near-Neutral pH Soil Environments*. Calgary, Alberta: s.n., 2006. IPC2006–10477.

Purports to address growth during hydrostatic testing via a hydrogen mechanism.

B.3 Management of Seam Weld Integrity

— Young, Bruce A., et al. *Overview of a Comprehensive Study to Understand Longitudinal ERW Seam Failures*. Calgary, Alberta: s.n., 2014. IPC2014–33226.

Closely related to the previous resource, the purpose of this paper is to provide an overview of the project, with focus on the study objectives, results, and ongoing work.

— Nanney, Steve. *Regulatory Next Steps in Addressing Pipeline Seam Weld Challenges*. Calgary, Alberta: s.n., 2014. IPC2014–33228.

This report discusses PHMSA's pipe seam efforts as of 2014, framing leak and failure history, past advisory bulletins, U.S. legislative and executive actions (statutory actions), recent U.S. NTSB findings, accident investigation findings, and ongoing research for pipe long seam welds.

— Michael Baker Jr., Inc. TTO Number 5, "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation," *Report to DOT Office of Pipeline Safety*, 2004.

This report documents a review focused on evaluation of longitudinal seams on LF-ERW pipe and lap welded pipe, particularly that manufactured before 1970, as well as DC-ERW pipe and EFW pipe.

— Kiefner, J.F. "Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines," *Technical Report to U.S. Department of Transportation Office of Pipeline Safety*, 2007

This report presents guidelines for evaluation of integrity management programs with respect to manufacturing and construction defects. Includes discussion of defects potentially present, fatigue, and pressure reversals.

— Johnson, Joshua and Nanney, Steve. *The Role, Limitations, and Value of Hydrotesting vs. In-line Inspection in Pipeline Integrity Management*. Calgary, Alberta: s.n., 2014. IPC2014–33450.

Paper presented by PHMSA that is focused on the shortcomings of ILI alone when assessing certain long-seam indications and/or cracks. Encourages the use of hydrostatic testing in conjunction with ILI to better identify these types of features.

B.4 Crack Growth

— Kania, Richard, Van Boven, Greg and Worthingham, Robert. *Achieving maximum crack remediation effect from optimized hydrotesting*. Calgary, Alberta: s.n., 2012. IPC2012–90635.

Recent research has shown that crack growth can occur during hydrostatic tests at smaller crack dimensions than those originally analyzed.

— Jaske, Carl E. *Assessment of Pipeline Fatigue Crack-Growth Life*. Calgary, Alberta: s.n., 2006. IPC2006–10155.

This RP is specifically designed to provide the operator with a description of industry-proven practices in the integrity management of cracks and threats that give rise to cracking mechanisms. Defects associated with lap-welded pipe and selective seam weld corrosion are not covered within this RP.

— Fearnehough, G.D., Hopkins, P. and Jones, D.G. *The Effect of Hydrostatic Test Hold Period on Defect Behavior and Surviving Defect Population*. New Castle, U.K.: s.n.

The effect of time dependence on defect behavior has been studied by comparing the rate sensitivity of the failure stress of notched bar specimens and the yield stress of tensile specimens. The results showed the link between the rate sensitivities of the failure stress and the material flow stress.

— Leis, B.N. and Brust, F.W. *Hydrotest Strategies for Gas Transmission Pipelines Based on Ductile-Flow-Growth Considerations*. July 31, 1992. NG-18 Report No. 194 SI Task 1.10–89.

Battelle study used to determine the growth of various flaw sizes as a result of having been subjected to combinations of test pressures and hold times and to assess the subsequent serviceability of pipelines containing those flaws in gas-transmission service.

— Leis, B.N., et al. *Hydrotest Protocol for Applications Involving Lower-Toughness Steels*. Calgary, Alberta: s.n., 2004. IPC04–0665.

This paper addresses the conditions for effective proof pressure testing in terms of ductile fracture referenced to peak pressure and hold time, and then contrasts these to the response in low-toughness situations.

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

This recommended practice provides guidance to the pipeline industry for assessment and management of defects in the form of cracking, with particular emphasis on contributing threats and the applicable assessments. This RP presents detailed guidance for developing a crack-management program.

B.5 Text Execution and Considerations

— Clark, E.B., Kiefner, J.F. *History of Line Pipe Manufacturing in North America*. New York: ASME CRTD Vol 43, 1996. 0–7918–1233–2.

Widely cited reference that provides a historical overview of line pipe manufacturing. Applicable to hydrostatic testing to understand the nature and type of defects that can be introduced due to the manufacturing processes.

— Bennett, Andrew Keith and Wong, Everett Clementi. *The Importance of Pre-Planning for Large Hydrostatic Test Programs*. Calgary, Alberta: s.n., 2010. IPC2010–31430.

Water sources are just one of the many important pre-planning activities that should be given adequate attention before the start of pipeline construction to successfully and efficiently manage a large pipeline hydrostatic test program.

— Zhou, Joe, Murray, Alan and Abes, Jake. *Implementation of Alternative Integrity Validation on a Large Diameter Pipeline Construction Project*. Calgary, Alberta: s.n., 2008. IPC2008–64479.

This paper summarizes the alternative integrity validation (AIV) implementation on the larger-diameter pipeline project and provides the perspectives from the pipeline company, regulator, and independent auditor.

— Edwards, Michael. *Pipeline Hydrostatic Pressure Test Pass/Fail Criteria used by a Regulatory Agency*. Calgary, Alberta: s.n., 2014. IPC2014–33040.

This paper describes the development and use of objective and subjective evaluation criteria for hydrostatic pressure tests of oil pipelines at marine terminal facilities by a California state agency.

— Zhang, Zhenyong, et al. *Research on Hydrostatic Test of the Test Pipe Section with a 0.8 Design Factor in the West-to-East China Gas Pipeline III*. Calgary, Alberta: s.n., 2014. IPC2014–33184.

This paper studies the approach using the P-V curve for pressure test control combined with the actual pressure test of pipelines with a 0.8 design factor, and validates the feasibility and accuracy of such an approach through the hydrostatic test of the test pipe section with a 0.8 design factor in the West-to-East China gas pipeline III.

— Yan, Feng, et al. *Study on Duration of Hydrostatic Leak Test for Gas Pipeline*. Calgary, Alberta: s.n., 2008. IPC2008–64034.

A mathematical model about the duration of hydrostatic leak tests for gas pipeline is developed for the first time in the paper. The influences of temperature variation, elastic deformation of the pipe, and a certain amount of residual air filled within the pipe are synthetically considered in the model.

— API Recommended Practice 1160, *Managing System Integrity for Hazardous Liquid Pipelines*.

This 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 several goals, including reducing both the number and consequences of incidents.

— 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*.

This RP provides guidelines for pressure testing steel pipelines for the transportation of gas, petroleum gas, hazardous liquids, highly volatile liquids, or carbon dioxide.

— API Recommended Practice 1176, *Recommended Practice for Assessment and Management of Cracking in Pipelines*.

This RP provides guidance to the pipeline industry for assessment and management of defects in the form of cracking, with particular emphasis on contributing threats and the applicable assessments. The RP presents detailed guidance for developing a crack-management program.

— Rosenfeld, M.J., and Gailing, R.W. *Pressure testing and recordkeeping: reconciling historic pipeline practices with new requirements*. Houston, TX: s.n., 2013.

This paper reviews the history of industry standards and regulatory requirements in the areas of hydrostatic pressure testing and recordkeeping.

— Kiefner and Associates, Inc. *Manufacturers' Hydrostatic Test Pressures*. July 26, 2006.

One-page summary table of pipe mill test pressures before and after 1941.

— Gray, JC. "How Temperature Affects Pipeline Hydrostatic Testing," s.l.: *Pipeline and Gas Journal*.

This document reviews the equations that are taken into consideration when determining if a temperature/pressure relationship allows for a successful test or if a leak is occurring.

— Michael Baker Jr., Inc. *Spike Hydrostatic Test Evaluation*. July 2004. OPS TT06.

This report documents an evaluation of the concept of using a spike hydrostatic test as applied to the hydrostatic reassessment of existing oil and gas pipelines.

— A.R., Duffy, et al. *Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure*. 1968.

Extensive historical background on the metallurgy, mechanics, and practical aspects of hydrostatic testing.

— Kiefner, J. *Hydrostatic Testing*. Worthington, Ohio: s.n., March 2001.

Summary of research results pertinent to hydrostatic testing and discussion of their implications.

— Kiefner, John F. and Maxey, Willard A. *The Benefits and Limitations of Hydrostatic Testing*.

A history of hydrostatic testing purposes and decision processes around the target pressures.

— Rosenfeld, J. Michael. *Hydrostatic pressure spike testing of pipelines: why and when?* s.l.: AGA, 2013.

Practical considerations for why and when to perform spike testing.

— Australian/New Zealand Standard AS/NZS 2885.5:2012, *Pipelines—Gas and Liquid Petroleum—Part 5: Field Pressure Testing.*

Australian standard that provides guidelines for pressure testing petroleum pipelines; a comparable document to API RP 1110.

B.6 Test Intervals

— Sen, Millan and Kariyawasam, Shahani. *Analytical Approach to Determine Hydrotest Intervals*. Calgary, Alberta: s.n., 2008. IPC2008–64537.

In IPC2006, an analytical method of determining hydrostatic test intervals, based on a time vs. pressure plot, was developed and published by Fessler et al. The study conducted examines this method, its assumptions, applicability, and limitations, with regards to an in-service pipeline system. It also discusses how this method was adapted to account for variable crack growth rates and failures.

— Kiefner, John F., et al. *Estimating Fatigue Life for Pipeline Integrity Management*. Calgary, Alberta: s.n., 2004. IPC04–0167.

The purpose of the paper is to show that while the well-known and widely available basic principles are sound, their application to pipeline integrity management requires an in-depth understanding of the particular pipeline being subject to assessment.

— API 579–1/ASME FFS-1 2007, *Fitness-For-Service*.

The methods and procedures in this standard are intended to supplement and augment the requirements in API 510, API 570, API 653, and other post-construction codes that reference FFS evaluations such as NB-23.

B.7 Test Failures and Detrimental Effects of Testing

— Kiefner, John F. and Kolovich, Kolin M. *A Study of Cases of Hydrostatic Tests where Multiple Test Failures Have Occurred*. Calgary, Alberta: s.n., 2010. IPC2010–31157.

The study described in this paper involved a review of five actual cases of hydrostatic tests where multiple test failures occurred. On the basis of these cases a method was developed for predicting the ultimate number of failures required to reach a desired test level from the pressure levels of the first few failures.

— Cosham, Andrew, et al. *A Historical Review of Pre-Commissioning Hydrotest Failures*. Calgary, Alberta: s.n., 2006. IPC2006–10333.

Historical data are summarized by year, in terms of the number of failures per km, and trends in the frequency and type of failures are identified.

— Rapp, Stephen C., et al. *Analysis of Pipe Expansion Associated with Field Hydrostatic Testing*. Calgary, Alberta: s.n., 2010. IPC2010–31666.

The purpose of this paper is to demonstrate that explanations other than low-yield strength pipe may be responsible for pipe expansion.

— Rosenfeld, M.J. *Integrity Implications of Unintentionally Expanded Line Pipe*. Calgary, Alberta: s.n., 2014. IPC2014–30177.

The paper presents a relationship between test pressure and diameter expansion, estimation of the reserve strain capacity, effects on fracture control, and effects on integrity reassessment intervals. The conclusions are that the integrity issues associated with limited magnitudes of diameter change can be readily managed.

— Adianto, Riski H. and Nessim, Maher A. *Limit States Design for Onshore Pipelines-Designing for Hydrostatic Test Pressure and Restrained Thermal Expansion*. Calgary, Alberta: s.n., 2014. IPC2014–33437.

This paper describes the process used to calibrate safety factors and characteristic input parameter values that meet the desired reliability levels. The results show that local buckling under restrained thermal expansion is only potentially relevant for a small subset of cases, and based on this, an explicit design rule was not developed.

— Brooks, Leon E. *High-Pressure Testing – Pipeline Defect Behavior and Pressure Reversals*. s.l.: ASME, 1968.

The paper discusses high-pressure testing of pipelines with specific reference to defect removal at different stress levels and behavior of defects during the holding period of the test. Pressure reversal is specifically reviewed.

— Duffy, A.R. *Studies of Hydrostatic Test Levels and Defect Behavior. Proc. of Symposium on Line Pipe Research*, AGA Catalogue No. L30000, pp. 139–160, 1965.

Studies of hydrostatic test levels and defect behavior during testing.

— Kiefner, John F. *Assessment of Cause of Hydrostatic Test Failure*, 1991.

Report reviewing the hydrostatic test failure of a 26-in. OD pipeline, with results appearing to point toward SCC. Page 6 indicates that a test to 100 % SMYS would buy more time between reassessments.

Annex C
(informative)

Understanding Stress Levels

C.1 General

The operative conceptual objective of hydrostatic pressure testing is to achieve a stress level in the pipeline test section greater than that experienced by the pipeline steel at operating pressure. This is done to ensure that flaws that could fail in service are eliminated, thus providing confidence that the pipeline can operate incident-free at operating pressure for a determined time period.

There are multiple methods (as detailed in Section 6) used to estimate the stress in the pipeline. Each method has specific benefits and utility, and it is useful to understand each.

C.2 Barlow's Formula

Barlow's formula (Equation C.1) is the pipeline industry standard for determining the pipe stress under internal pressure. With this equation, it is relatively simple and straightforward to set an input target, maximum, minimum, or other stress level, and calculate the corresponding pressure. This can also be easily rearranged to calculate stress from a corresponding pressure. Barlow's formula is also the basis for pipeline design as reflected in ASME B31.8, B31.4, and most regulatory codes.

$$\sigma_{h_{Barlow's}} = \frac{P * OD}{2t} \qquad \text{(C.1)}$$

Where:

P	internal pressure
σ_h	hoop stress
t	wall thickness
OD	outside diameter

Barlow's formula uses the outside diameter of the pipeline as a conservative method of determining hoop stress for internal pressure. The formula shown in Figure C.1, utilized for thick-walled cylinders, provides a more accurate method for determining the hoop stress.

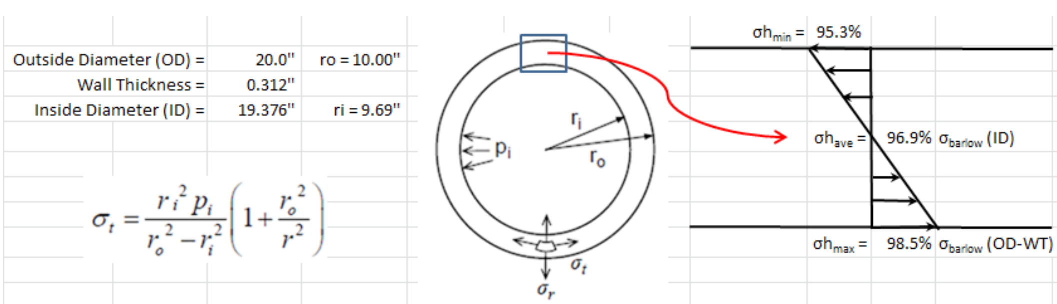

Figure C.1—Hoop Stress in Thick-walled Cylinders

As shown in Equation C.1, the average hoop stress across the wall thickness is the same stress as utilizing Barlow's formula but substituting the inside diameter (ID). The maximum stress at the ID surface is equal to utilizing OD minus WT. In the case shown above, the actual hoop stress may be up to 3.1 % lower than that provided by Barlow's formula. Given variations in diameter and wall thickness, Barlow's formula is considered conservative.

C.2.1 von Mises Equivalent Stress or Effective Stress

Another limitation of Barlow's formula is that it is an expression that considers only the hoop stress, as it is the largest component of the combined stress and, consequently, dominates the analysis.

The von Mises equivalent stress provides the ability to model a more realistic behavior of a material under multi-axial loading conditions by considering the effects of the applicable major stress components (bi-axial or tri-axial).

When subjected to internal pressure, a pipeline is subjected to hoop stress in the circumferential direction, but is also subjected to axial stress acting parallel to the pipeline. When hoop stress is applied, a pipe section will contract axially, getting slightly shorter due to the effect described by Poisson's ratio.

Mill hydrostatic test practices typically use a hydraulic ram to provide a pressure seal on the ends of the pipe being tested. In the case of a mill test, the ram will follow the contraction to maintain a pressure seal during the test, applying a longitudinal compressive force to the pipe. This would effectively reduce the amount of hoop stress being required to achieve SMYS.

Contrast this to a field pressure test of a buried pipeline, where soil friction along a length of pipeline resists axial contraction, resulting in an axial tensile stress equal to Poisson's ratio times the hoop stress (0.3 for steel). This would effectively increase the amount of hoop stress being required in the field to achieve SMYS.

This relationship is shown graphically in Figure C.2, where the von Mises equivalent stress is represented as a yield ellipse. The ellipse represents the yield stress curve of the pipe material, and the length of the radius is the total combined stress required to reach the yield point. The magnitude of hoop stress to produce yield at any point along the ellipse is the Y-coordinate, or the vertical component, of the radius. Note that the ellipse crosses the Y-axis at a value of 1. This corresponds to pure hoop stress with no axial component (representative of a uniaxial tensile specimen); applying compressive stress (negative longitudinal stress) decreases the available hoop stress prior to yield, whereas tensile stress (positive) increases the hoop stress required to reach yielding. The result is that the pressure to produce yielding in a buried pipe can be up to 12.5 % higher than for pipe under hydrostatic test in the mill if compressive force is used to maintain the seal.

This should not be interpreted to mean that field hydrostatic tests can confidently exceed SMYS or previous tests, including mill tests to API 5L or 5LX minimums in every case. Mill test practices may utilize a range of compressive loads or alternative methods of sealing end caps during mill testing.

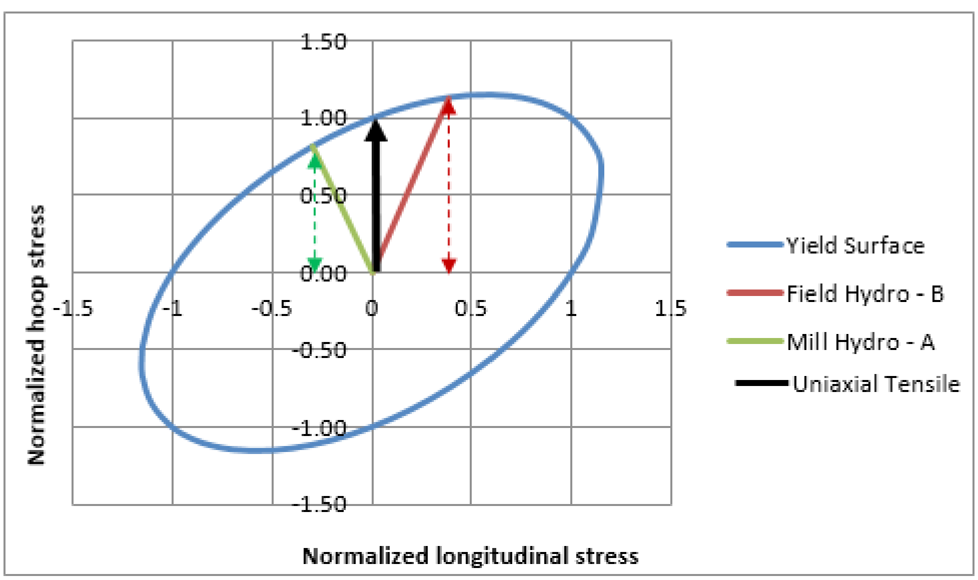

Figure C.2—von Mises Equation Represented as a Yield Ellipse

C.2.2 Variation in Material Properties

Variability exists in material properties.

API 5L specifications ensure that pipes have yield strengths greater than the specified minimum. Therefore, there is a bias inherent between SMYS and measured yield strengths. API 5L PSL2 allows actual yield strength to be 21.7 ksi to 29.8 ksi above specified minimum (grade dependent). The histogram shown in Figure C.3 represents a distribution of X52 line pipe taken from a hazardous liquids pipeline operator's material records for a 30-in. diameter pipeline.

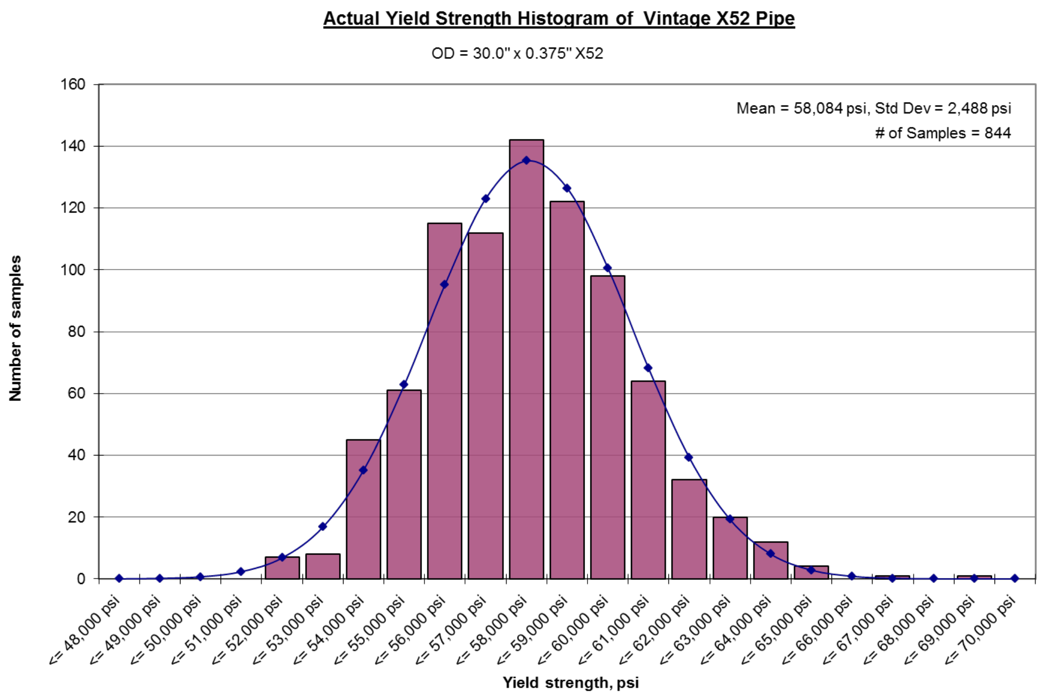

Figure C.3—SMYS Histogram for X52 Pipe

API 5L also allows for 12.5 % wall thickness variation (8 % in larger diameters). These allowed wall thickness tolerances are to handle localized variations in wall thickness. Generally, a localized reduction in wall thickness is a result of a mill flaw that has been ground out. Global wall thickness variations have smaller tolerances and are monitored by measuring by the mass of each individual pipe joint. The range is +10 % down to −3.5 %.

C.2.3 Bauschinger Effect

The tensile test commonly used to assess the yield strength of line pipe is a transverse, flattened uniaxial specimen designed to test the circumferential (hoop) direction tensile properties. A test of such a specimen reveals a unique value of yield strength at a certain amount of applied stress under uniaxial loading.

It is commonly observed that the tensile properties of the specimen differ from the tensile properties of plate or pipeline steel. Flattening of the strap will typically reduce the measured yield strength when the strap is tensile tested, e.g., the measured strap yield will be less than the hoop yield strength of the pipe. This change in properties of the test specimen is due to the Bauschinger effect. A recent study concluded that the change in yield point is particularly pronounced compared to the change in ultimate tensile strength. Therefore, a flattened strap will have a lower measured yield than the yield point of the line pipe itself. The effects will vary by pipe material, and do not invalidate any certified SMYS ratings as API 5L specification requires flattened strap specimens to meet the reported strengths of the pipe, but this effect introduces more conservatism into the design of pipeline components.

The Bauschinger effect has been extensively studied, and a discussion of the phenomena as applicable to pipe forming and flattening of straps was reviewed in development of this technical report[25]. The reference discusses development of a model for identification of final material properties, but for the purposes of this technical report, it is enough to explain that the measured tensile stress of a flattened strap is expected to be less than the actual tensile strength of the pipe from which it was taken.

[25] Thibaux, P., Van Hoecke, D., De Vos, G., *Influence of Forming and Flattening on the Measured Tensile Properties of Linepipe*, IPC2006-10116, ASME.

Bibliography

[1] Leis, B.N. and Rahman, S. " Risk-Based Considerations in Developing Strategies to Ensure Pipeline Integrity – Part 1: Theory." Journal of Pressure Vessel Technology, August 1994.

[2] Kiefner, K.M. and Kolovich, J.F. *Effectiveness of Hydrostatic Testing for Assessing the Integrity of ERW and Flash-weld Pipe Seams.* January 2013.

[3] INGAA.. *Comments of the Interstate Natural Gas Association of America to Docket ID PHMSA- 2005-23447*. 2005. Notice 2, Docket No. RIN 1010-AD11.

[4] Jacobs Consultancy Inc.. and Gas Transmission Systems Inc. *Technical, Operation, Practical, and Safety Considerations of Hydrostatic Pressure Testing Existing Pipelines*. December 5, 2013.

[5] Kiefner, J.F. and Trench, C.J. *Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction.* 2001.

AMERICAN PETROLEUM INSTITUTE

200 Massachusetts Avenue, NW
Suite 1100
Washington, DC 20001-5571
USA

202-682-8000

Additional copies are available online at www.api.org/pubs

Phone Orders:	1-800-854-7179	(Toll-free in the U.S. and Canada)
	303-397-7956	(Local and International)
Fax Orders:	303-397-2740	

Information about API publications, programs and services is available on the web at www.api.org.

Product No. D11791