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DTPH5615T00009 Development of Comprehensive Pressure Test Design Guidelines - Task 6: Pressure Test Evaluation Guidelines

Cara Macrory-Dalton

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DTPH5615T00009 DEVELOPMENT OF COMPREHENSIVE PRESSURE TEST DESIGN GUIDELINES - TASK 6: PRESSURE TEST EVALUATION GUIDELINES

to

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

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DTPH5615T00009 Development of Comprehensive Pressure Test Design Guidelines - Task 6: Pressure Test Evaluation Guidelines

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INTRODUCTION

The scope of this Task 6 report is to document the developed guidelines related to the evaluation phase of pressure tests. Kiefner and Associates, Inc. (Kiefner) developed these guidelines for best practices based on a review of currently available industry documents, interviews with pipeline operators and pressure test contractors, and Kiefner's own experience with pressure testing.

SUMMARY

This Task 6 report intends to provide the industry with clear guidance related to pressure test evaluation. The key design aspects of pressure test evaluation covered by this document include the following:

- statistical distribution of pipe material properties,
- potential for and effects of yielding,
- criteria for acceptable limits on pipe expansion,
- reassessment intervals for various time dependent defect growth mechanisms,
- longitudinal seam failure susceptibility analysis, and the
- use of pressure testing to validate the results of in-line inspections (ILI).

Work related to providing guidance for other topics, including safety (Task 7) is ongoing. Guidelines developed for Task 7 will be provided in a separate report.

BACKGROUND

The objective of the Development of Comprehensive Pressure Test Design Guidelines Project (DTPH5615T00009, Project #645) is to develop comprehensive guidelines for the design of pipeline pressure tests that could be incorporated into industry standards and operator procedures. A goal of this project is to provide guidance on how to plan, execute, and evaluate pressure tests based on the most current knowledge and industry needs. The work takes into

account the significant amount of research on pressure testing that has been carried out from the 1960s through the present by government, private, and industry organizations.

Task 2 was a review of existing industry standards, recommended practices, research papers and other literature related to the pressure testing of liquid and natural gas pipelines. Task 2 determined the scope of the information already covered in existing guidance documents and identified deficiencies or disagreements, or both, between reviewed documents. The results of Task 2 were reported on January 26, 2016 in Kiefner Final Report No. 16-009, "DTPH5615T00009 Development of Comprehensive Pressure Testing Guidelines – Task 2: Review of Existing Industry Standards and Recommended Practices". The following documents were reviewed:

- ASME B31.8-2014 Gas Transmission and Distribution Piping Systems
- ASME B31.8S-2014 Managing System Integrity of Gas Pipelines
- ASME B31.4-2012 Pipeline Transportation Systems for Liquids and Slurries
- API 1160-2013 Managing System Integrity for Hazardous Liquid Pipelines
- API 1110-2013 Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide
- INGAA Report No. 2013.03 "Technical, Operational, Practical, and Safety Considerations of Hydrostatic Pressure Testing Existing Pipelines"
- TTO Number 6 "Spike Hydrostatic Test Evaluation", July 2004

The results of the review specific to pressure test evaluation related topics are summarized in Table 1. The table shows which pressure test evaluation related topics are currently covered in each of the above listed documents. A topic is considered covered (denoted with a "yes" in Table 1) if relevant language is introduced in the document with some level of detail or discussion. A covered topic does not necessarily imply a prescriptive guideline is provided. The key concept related to pressure test evaluation identified for clarification by Task 2 is reassessment interval determination.

Table 1. Test Evaluation Topical Comparison of Industry Documents

	Title 49 CFR Part 192	Title 49 CFR Part 195	ASME B31.8	ASME B31.8S	ASME B31.4	API 1160	API 1110	INGAA Report	TTO No. 6
Reassessment Intervals	Yes	Yes	Yes	Yes	No	Yes	Yes	Refers to Title 49 CFR Part 192	Yes
Effect of Yielding or Expansion	No	No	No	No	No	No	No	No	No
Testing in-situ as an Indicator of Yield Strength	No	No	Yes	No	No	No	No	No	No
Test Failure Evaluation	No	No	No	No	No	Yes	Yes	Yes	No

The goal of Task 3 was to capture knowledge from liquid and gas pipeline operators and pressure testing service contractors relevant to pressure testing guidelines, as well as identify inconsistencies or gaps in pressure testing practices. Interviews with three pipeline operators and two pressure test services contractors were conducted by telephone and by written correspondence. The results of Task 3 were reported on June 30, 2016 in Kiefner Final Report No. 16-091, "DTPH5615T00009 Development of Comprehensive Pressure Test Design Guidelines - Task 3: Interview Pipeline Operators and Pressure Test Service Contractors".

Through the interviews conducted during Task 3, it can be concluded that pressure testing is a topic of broad industry interest. It was determined that the industry needs education on and consistent procedures for the following topics related to pressure test evaluation:

- potential for and effects of yielding,
- longitudinal seam failure susceptibility analysis, and
- pressure testing for the long term service of various time dependent threats.

Clarification on the key topics summarized here is necessary in order to provide the industry with one comprehensive document that provides clear guidance in the case of conflicts and dispels any misinformation or inappropriate guidance.

The goal of Task 4 was to document the developed guidelines related to the planning phase, or pre-execution phase, of pressure tests. The results of Task 4 were reported on December 30, 2016 in Kiefner Final Report No. 16-224, "DTPH5615T00009 Development of Comprehensive Pressure Test Design Guidelines - Task 4: Pressure Test Planning Guidelines".

The goal of Task 5 was to document the developed guidelines related to the execution phase of pressure tests. The results of Task 5 were reported on June 30, 2017 in Kiefner Report,

"DTPH5615T00009 Development of Comprehensive Pressure Test Design Guidelines - Task 5: Pressure Test Execution Guidelines".

Note that the scope of this project is to develop guidelines related to pressure testing. Pressure testing encompasses two forms of pipeline pressurization: pneumatic which uses a compressible gas as the test medium and hydrostatic which uses a liquid as the test medium. The most common test medium for a pneumatic pressure test is nitrogen and the most common test medium for hydrostatic testing is water. Some guidelines documented by this task will distinguish between hydrostatic or pneumatic testing and the broader category of pressure testing.

PRESSURE TEST EVALUATION GUIDELINES

Pressure Test Evaluation Overview

Upon completion of a pressure test the results should be studied to confirm the intended targets of the assessment were met and to evaluate the overall value of the assessment on pipeline integrity. Did the pressure test address pipeline specific threats and operational needs? Was the test-pressure-to-operating-pressure ratio (TPR) sufficiently high for long-term operational safety, and was it used to establish a re-inspection interval for the control of time-dependent defect growth? The answers to these questions should be yes if the guidelines outlined by Task 4 and Task 5 of this project were followed, however an operator should evaluate and document the actual test results to verify the pipeline integrity goals were achieved and support the current and future integrity management plans.

An evaluation of a pressure test should include:

- establishing maximum allowable operating pressure (MAOP) or maximum operating pressure (MOP),
- metallurgical failure investigation of pipe failures,
- estimating potential remaining flaw sizes and populations,
- estimating time-to-failures for time dependent flaws,
- establishing a reassessment interval for pipeline integrity,
- analyzing the relative risk for longitudinal seam weld failure, and
- validation of ILI.

Test Failure Investigation

The objective of a metallurgical failure analysis of a line pipe failure is to assign one or more probable causes for the failure. The failure analysis may identify issues that must be remediated to ensure the integrity of other sections of the failed line pipe as well as other

pipeline segments with similar characteristics (i.e. pipe manufacturer, seam type, grade, other specifications, coating type, and environmental conditions). It is recommended that all pressure test failures undergo a thorough, potentially third party, metallurgical failure investigation unless there is substantial evidence that the cause of failure is known (such as a series of gouges without surface cracking, indicative of third party damage).

A typical sequence of analysis and an example failure analysis protocol are provided in Appendix A. It is recommended that a failure investigation include the review, execution, and documentation of the following:

- background information
    - pipe attributes (such as outside diameter, wall thickness, grade, vintage, manufacturer, and seam type)
    - location of the failure by state, county, section, township, range, tract number, and station number
    - deadweight pressure at time failure was detected
    - calculated pressure at location of the failure correcting for elevation
    - date and time the failure was detected, method used, and test attempt number
    - date and time the failure was located and method used
    - date and time the failure was repaired and description of the repair (such as entire joint replacement or repair sleeve)
    - location of the failure origin and clock position
    - mode of failure (leak or rupture)
- custody transfer and control
- photographic documentation
- visual and nondestructive examination
- physical measurements
- corrosion examination
- fractographic examination
- metallographic examination
- mechanical properties testing

Based on the review of any previous failures combined with findings from the current pressure test assessment, certain conclusions on the pipeline could be made, including:

- Evidence of a common cause of failure
- Evidence of a common mode of failure
- Pipeline section(s) that exhibits a higher rate of failure
- Identification of primary threats
- Evidence of susceptibility to pressure reversals

- Evidence of non-conformance with indicated pipe grade

Further preventative or mitigative action may be warranted by a pipeline operator if any of the above conclusions are made; such as a reduction in pipeline operating pressure or advanced reassessment schedules.

Statistical Distribution of Pipe Material Properties

Research and destructive testing have shown significant variability in yield strength (YS) and ultimate tensile strength (TS) values from specified minimums, which collectively affect flow stress estimates. Most line pipe is over-strength. Annex D of API RP 1176 provides destructive test results for yield strength and tensile strength measurements from several hundred tests performed on material samples covering a broad range of grades, vintages, and sources[i]. The results are reproduced below to illustrate the distribution of strength values per grade and difference between the lower 5th percentile (L5), mean, and upper 95th percentile (U95) values (see Table 2, Table 3, Figure 1, and Figure 2). The greatest variability in YS was observed in Grade X56, followed by Grade B pipe. The greatest variability in TS was observed in Grade X52, followed by Grade B pipe.

Table 2. Database Yield Strength (YS) Properties by Grade

Grade	SMYS lb/in.^{2} (MPa)	Mean YS lb/in.^{2} (MPa)	StdDev lb/in.^{2}. (MPa)	SD/Mean	U95 YS = AvgYS+1.64sd lb/in^2. (MPa)	L5 S = AvgYS−1.64sd lb/in.^{2} (MPa)
A/Bessemer/ Open Hearth	30,000 (210)[a]	39,997 (275.77)	4,535 (31.27)	0.113	47,434 (327.04)	32,560 (224.49)
B	35,000 (245)	48,641 (335.37)	7,795 (53.74)	0.160	61,425 (423.51)	35,857 (247.22)
X42	42,000 (290)	52,228 (360.1)	6,396 (44.09)	0.122	62,717 (432.42)	41,739 (287.78)
X46	46,000 (320)	53,723 (301.46)	5,963 (39.25)	0.111	63,502 (437.83)	43,944 (302.98).
X52	52,000 (360)	59,192 (408.11)	5,983 (41.25)	0.101	69,004 (475.77)	49,380 (340.46)
X56	56,000 (390)	62,833 (433.22)	8,704 (60.01)	0.139	77,108 (531.64)	48,558 (334.79)
X60	60,000 (415)	68,660 (473.39)	5,390 (37.16)	0.079	77,500 (534.34)	59,820 (412.44)
X65	65,000 (450)	72,003 (496.44)	2,884 (19.88)	0.040	76,733 (592.05)	67,273 (463.83)
X70	70,000 (485)	80,438 (554.60)	4,996 (34.45)	0.062	88,631 (611.09)	72,245 (498.11)

[a] Actual range was YS=25 to 30 ksi (172 MPa to 207 MPa), UTS=45 to 50 ksi (210 MPa to 345 MPa)

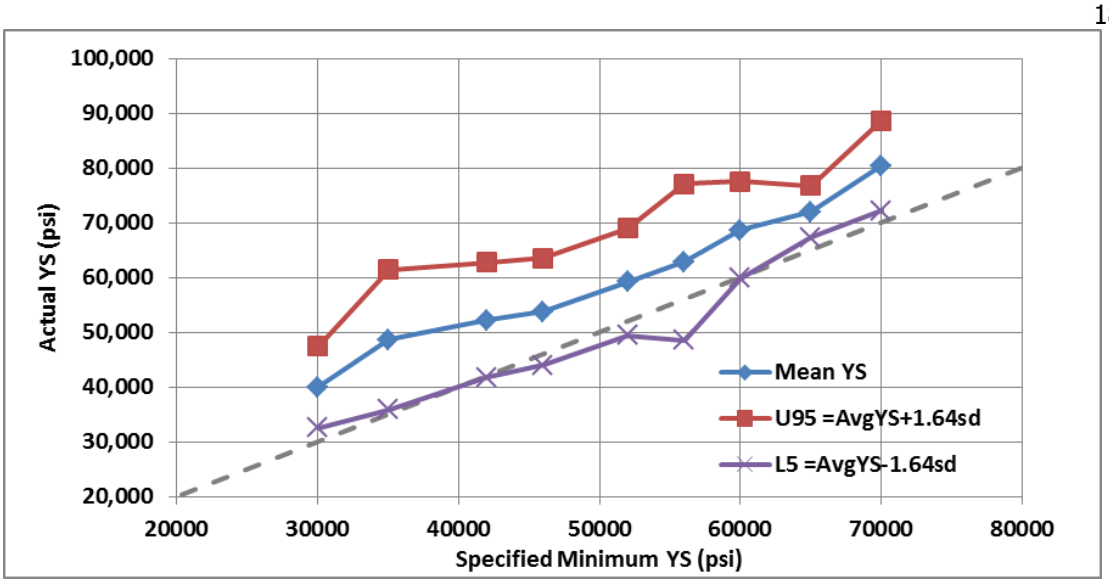


Figure 1. Database YS Properties by Grade

Table 3. Database Tensile Strength (TS) Properties by Grade

Grade	SMTS lb/in.^{2} (MPa)	Mean lb/in.^{2} (MPa)	StdDev lb/in.^{2} (MPa)	SD/Mean	U95 TS = AvgTS+1.64sd lb/in.^{2} (MPa)	L5 TS = AvgTS−1.64sd lb/in.^{2} (MPa)
A/Bessemer/ Open Hearth	50,000 (345)	55,711 (384.11)	5,266 (36.31)	0.095	64,347 (443.66)	47,075 (324.57)
B	60,000 (415)	68,551 (472.64)	7,062 (48.69)	0.103	80,133 (552.50)	56,969 (392.79)
X42	60,000 (415)	70,533 (486.31)	5,091 (35.10)	0.072	78,882 (543.87)	62,184 (428.74)
X46	63,000 (435)	73,117 (504.12)	6,312 (43.52)	0.086	83,469 (575.50)	62,765 (432.75)
X52	66,000 (460)	78,688 (542.53)	8,698 (59.97)	0.111	92,953 (640.89)	64,423 (444.18)
X56	71,000 (490)	85,083 (586.62)	7,304 (50.36)	0.086	97,062 (669.22)	73,104 (504.03)
X60	75,000 (520)	86,598 (597.07)	6,644 (45.81)	0.077	97,494 (672.20)	75,702 (521.95)
X65	77,000 (535)	89,424 (616.56)	5,915 (40.78)	0.066	99,125 (683.44)	79,723 (549.67)
X70	82,000 (570)	96,125 (628.28)	5,786 (39.89)	0.060	105,614 (728.18)	86,636 (597.33)

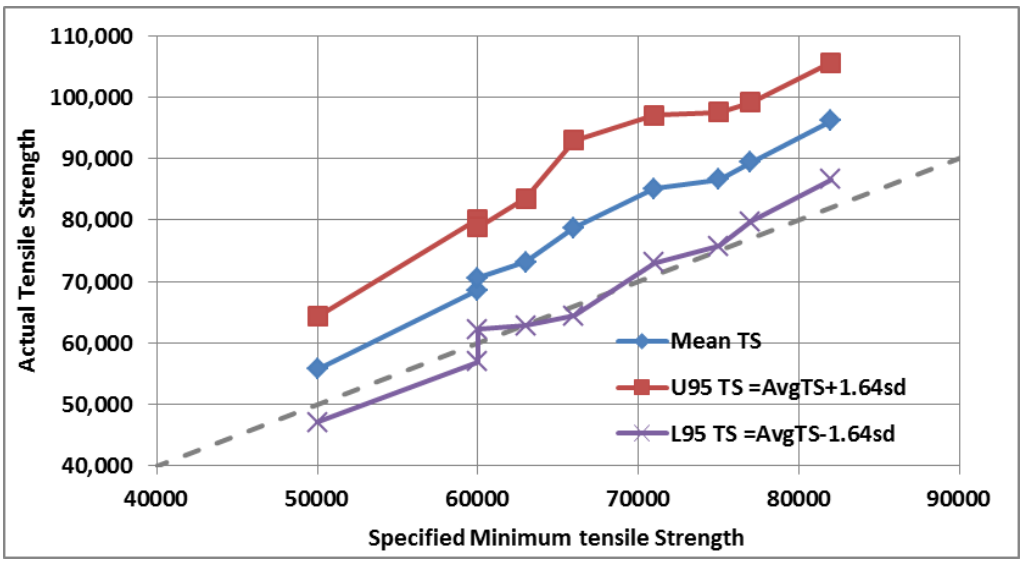


Figure 2. Database TS Properties by Grade

Toughness is another material property that can vary widely and, if less than optimal[1], can influence the effectiveness of pressure testing with respect to the elimination of defects. Annex E of API RP 1176 provides guidelines on how to estimate toughness values when unknown or mill test reports (MTRs) are unavailable. The guidelines were derived from a rather extensive dataset developed from the PHMSA study on electric-resistance weld (ERW) pipe[ii]. The dataset from the PHMSA study provided a wide range of Charpy V-notch (CVN) transition curves taken from vintage ERW pipelines, many associated with the bondline and weld heat affected zone (HAZ) region. The API RP 1176 guidelines provide a method to identify a toughness value for vintage ERW pipe at a target probability level.

The optimal toughness concept was expressed by Kiefner, Maxey, Eiber, and Duffy in the basis paper for the NG-18 ln-secant equation, "Failure Stress Levels of Flaws in Pressurized Cylinders", STP 536, 1972. Fully flow-stress-dependent behavior is achieved when the ratio

$$\boldsymbol{\beta} = \frac{\boldsymbol{K_c^2 \pi}}{\boldsymbol{8 c \sigma_f^2}} \geq \boldsymbol{4} \qquad \textbf{Equation 1}$$

[1] As stated in API RP 1176: fracture mechanics assessment relationships between flaw size and failure stress level in pressurized pipe, including API 579 FAD, modified ln-secant, and CorLAS™, generally indicate that a limiting toughness level is reached beyond which no further improvement in failure pressure occurs with increased toughness level. This level is the "optimal toughness." If the actual toughness exceeds the optimal toughness level, the failure is controlled by the material ductile strength; e.g., the flow stress or perhaps the ultimate strength. The optimal toughness often falls in the range of 27 J to 81 J (20 ft-lb to 60 ft-lb), depending on pipe size and operating stress.

where K_c is a plane stress fracture toughness, c is half the critical crack length, and σ_f is the material flow stress. But as shown below in Figure 3, strength-dependency is approached asymptotically, and 90% of the maximum limit occurs where β>2. Maxey showed that the plane stress fracture toughness can be related to the CVN upper shelf energy, C_V, as $(K_c)^2=C_VE/A_c$ where E is the elastic modulus and A_c is the cross sectional area of the CVN specimen. Considering a defect length of one pipe-diameter, 2c=D, then 90% flow-stress-dependency occurs where the full-size CVN upper shelf energy is

$$C_V \geq \frac{8DA_c\sigma_f^2}{\pi E} \qquad \textbf{Equation 2}$$

Considering flow stress as YS+10 ksi per STP 536, some estimated levels of optimal toughness are as shown for various pipe diameters and grades in Figure 4. The optimal toughness increases with pipe diameter, defect length (although this is influenced by an erroneous artifact of the ln-secant model), and flow stress. Optimal toughness for a given circumstance can be determined by performing failure stress levels in accordance with the Modified ln-secant equation (which corrects the defect length problem in the original ln-secant equation) while varying flaw sizes and CVN upper shelf values as input. As the optimal toughness is approached, the failure stress will cease to increase noticeably for greater CVN input values.

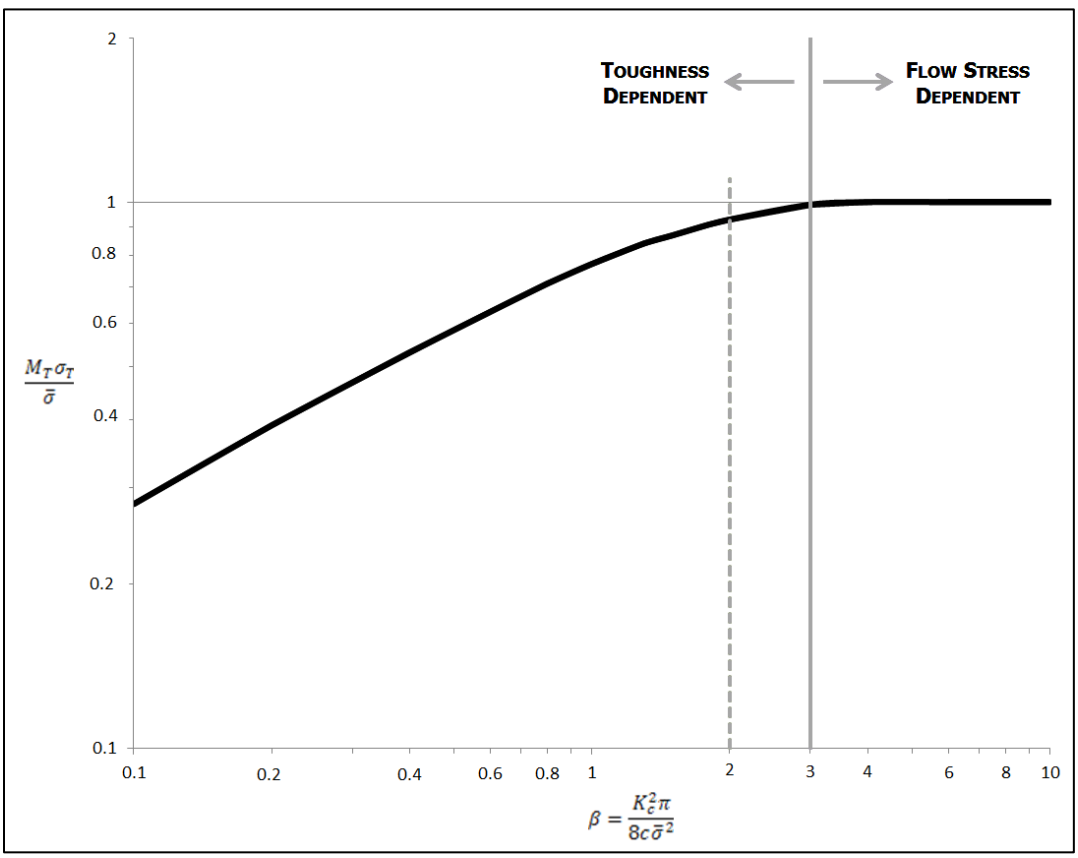


Figure 3. Strength Dependency with Flaw Severity (from STP 536)

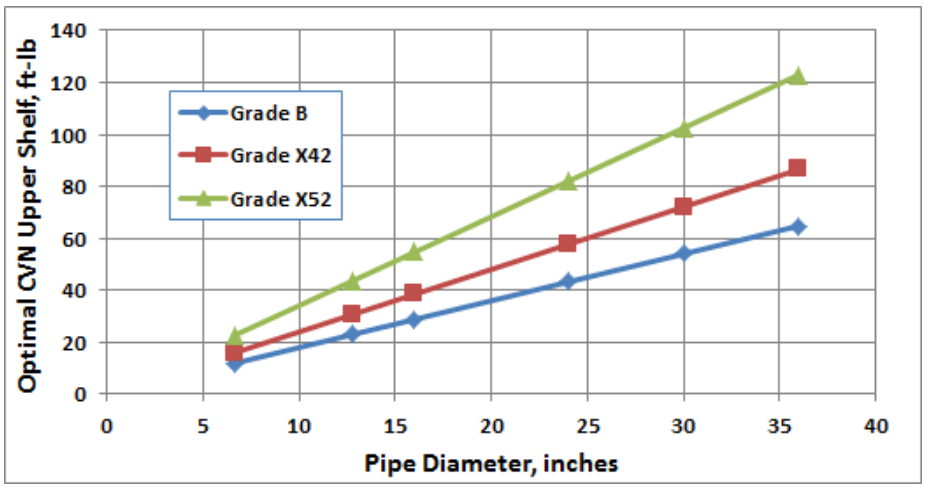


Figure 4. Example Optimal Toughness Levels

Pipe Yielding

Yielding of a ductile material, such as carbon steel, happens when the von Mises stress (also known as equivalent or combined stress) reaches the material yield stress. Equivalent combined stress under biaxial loading is calculated as:

$$\boldsymbol{\sigma_{eq}} = \sqrt{\boldsymbol{\sigma_L^2} + \boldsymbol{\sigma_H^2} - \boldsymbol{\sigma_L} \cdot \boldsymbol{\sigma_H}} \qquad \textbf{Equation 3}$$

where:

σ_L is the longitudinal stress,

σ_H is the hoop stress, and

σ_{eq} is the von Mises stress.

Equation 1 ignores through-thickness stress. This relationship is shown in Figure 5 which plots the combination of longitudinal and circumferential stress that would result in yielding.

From the biaxial stress equation and Figure 5 it can be understood that when both the hoop stress and the longitudinal stress are tensile it is possible for one of these stress components to exceed the yield strength slightly without yielding occurring. To show this we consider a pipe with longitudinally restrained and unrestrained conditions, subject to internal pressure and no significant external loadings. Under restrained conditions the longitudinal stress which is generated by the internal pressure is Poisson's ratio (0.3 for carbon steel) times the hoop stress. Using $\sigma_L = 0.3\sigma_H$ and solving Equation 1 for $\sigma_{eq} = \sigma_y$ where σ_y is the yield stress, results in a hoop stress of $1.125\sigma_y$. Therefore, yielding does not happen until the hoop stress

exceeds the yield stress by 12.5%. In an unrestrained straight pipe the longitudinal stress is 50% of the hoop stress. Under the unrestrained condition yielding occurs when the hoop stress exceeds the yield stress by 12.5%. The actual yield strength in most pipe is greater than SMYS, further elevating the pressure capacity before yielding. Therefore, yielding of a pipe during a pressure test to hoop stress levels somewhat above 100% SMYS is not expected provided the pipeline as-installed is not subjected to large external loadings at the time of the test.

The curve in Figure 5 to the left of the vertical axis also shows that if the hoop stress is high, it takes very little longitudinal compression to result in yielding (or conversely if the axial compressive stress component is large, it takes little circumferential stress to cause yielding). Thus if a portion of the pipeline undergoing high level testing experiences large external loadings which may place the pipe section in net longitudinal compression or bending, yielding may occur. Situations where such external loadings could affect lengths of buried pipeline may include, but are not limited to:

- zones of post-installation settlement or uneven support below the pipeline;
- elastic bends or where pipe was roped to the ground contour;
- at the entry or exit to swampland or having unevenly spaced weight such that it is subjected to differential buoyancy;
- at the toe of steep slopes.

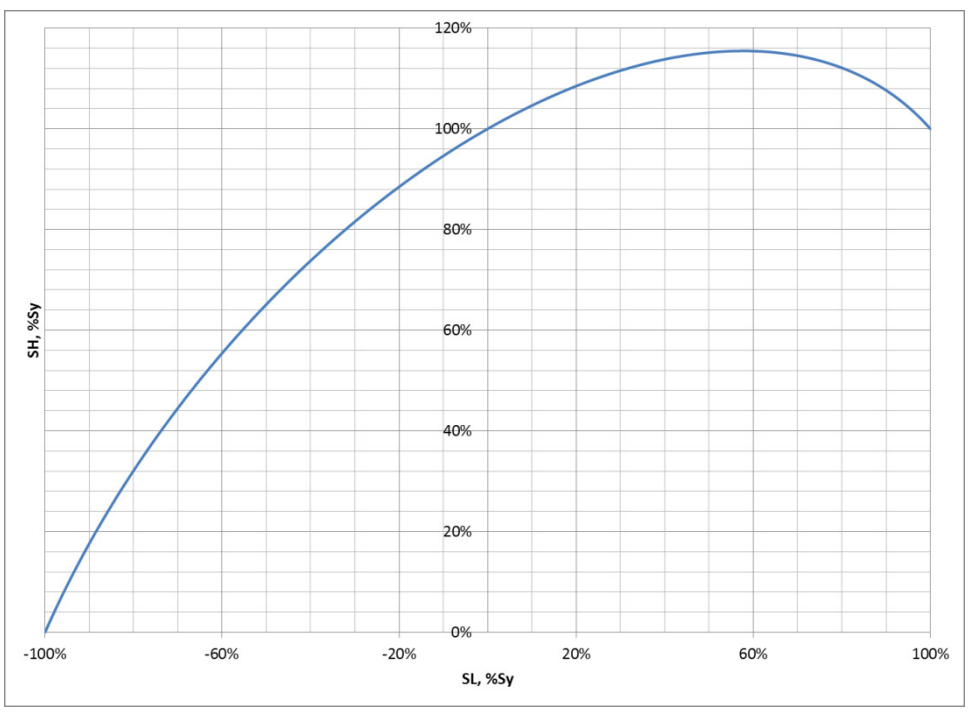


Figure 5. Relationship for Yielding in Biaxial Loading

The consequence of yielding, if it occurs, depends on the extent of the yielded zone and the amounts of plastic deformation. A uniform axial stress usually does not change rapidly along a buried pipe. A uniform compressive axial stress (for example from long-wall subsidence or moving slope), if it is high enough, can cause a long segment of a pipe to yield during a pressure test. Under this scenario the entire pipe cross-section is expected to yield, leading to expansion of the pipe diameter and potentially reduction of the pipe wall thickness. Ambient temperature creep is another potential consequence of excessive yielding. Yielding of a long pipe segment during a pressure test can be detected by measuring fluid volume, and location(s) of the yielded segments can be determined by means of ILI using a geometry tool.

Bending stress usually changes rapidly along a pipe, while it varies from compressive to tensile around the pipe circumference. As such, the yielded zone resulting from combined hoop and compressive bending stress is expected to be relatively small and only affect a portion of the pipe circumference with the utmost distance from the bending neutral axis.

The normality principal states that the strain vector will be perpendicular to the yield curve. This vector, normal to the left half of the curve in Figure 5, will exhibit a positive circumferential component indicating that the pipe will swell or bulge radially outward, which is consistent with experience and observation.

Testing in-situ as an Indicator of Yield Strength

Information can be acquired during a hydrostatic test that will indicate whether or not yielding of pipe is occurring. The type of information needed is a plot of pressure versus volume of water being added (a PV plot) as the test is being conducted. Most pipeline hydrostatic testing companies are familiar with this concept and are usually equipped to make such a plot if it is requested.

The volume of water being added is taken from a stroke-counter on the positive-displacement pump. Each stroke corresponds to a fixed volume of water being added. The plot can be made manually by the technician overseeing the dead-weight pressure gauge. Every 10 psi the technician calls out the pressure, and another technician monitoring the pump-stroke counter calls out the cumulative number of strokes. The first technician then enters the data on the PV plot. Some testing contractors may have automated systems to do this. In any case, after any residual air in the test section has been sufficiently compressed (usually by the time the pressure gets to 300 psi), the PV slope becomes and remains linear until or unless a leak occurs or yielding of the weakest pipe begins to take place. The theoretical linear slope can be shown to be a function of the diameter, wall thickness, and elastic modulus of the pipe and the bulk modulus of water at the test temperature.

If no leak is present and yielding begins, the slope of the PV plot will deviate from the linear plot generated while the pipe is still behaving elastically. The slope will begin to decrease at an increasing rate as the yielding of additional pipes begins. To avoid excessive amounts of yielding, it is prudent to terminate additional pressurization when the slope declines to one-half of the originally observed elastic slope. At that point the pressure becomes the effective maximum test pressure.

A leak can mask or mimic yielding because a leak takes away water being added. It is possible to determine if a slope deviation is being caused by a leak. To do so, the pressurization should be stopped temporarily. The pressure may drop slightly at that point whether due to a leak or to yielding. However, if the decrease is due to yielding the pressure will stop dropping whereas it will not stop dropping if a leak is present.

An alternative approach to determining whether a pressure reduction is due to a leak or temperature effects is to plot the test pressure versus log-time. In normal time coordinates, the pressure loss due to a leak will tend to be approximately linear as shown by the dashed red line in Figure 6(a) below, whereas the pressure loss due to cooling of the test water will asymptotically approach a stable value because the cooling rate slows as the thermal differential decreases. In log-time coordinates, the pressure loss due to a leak will exhibit a downward curve whereas pressure loss due to test water cooling will tend to follow a linear path, as shown in Figure 6(b).

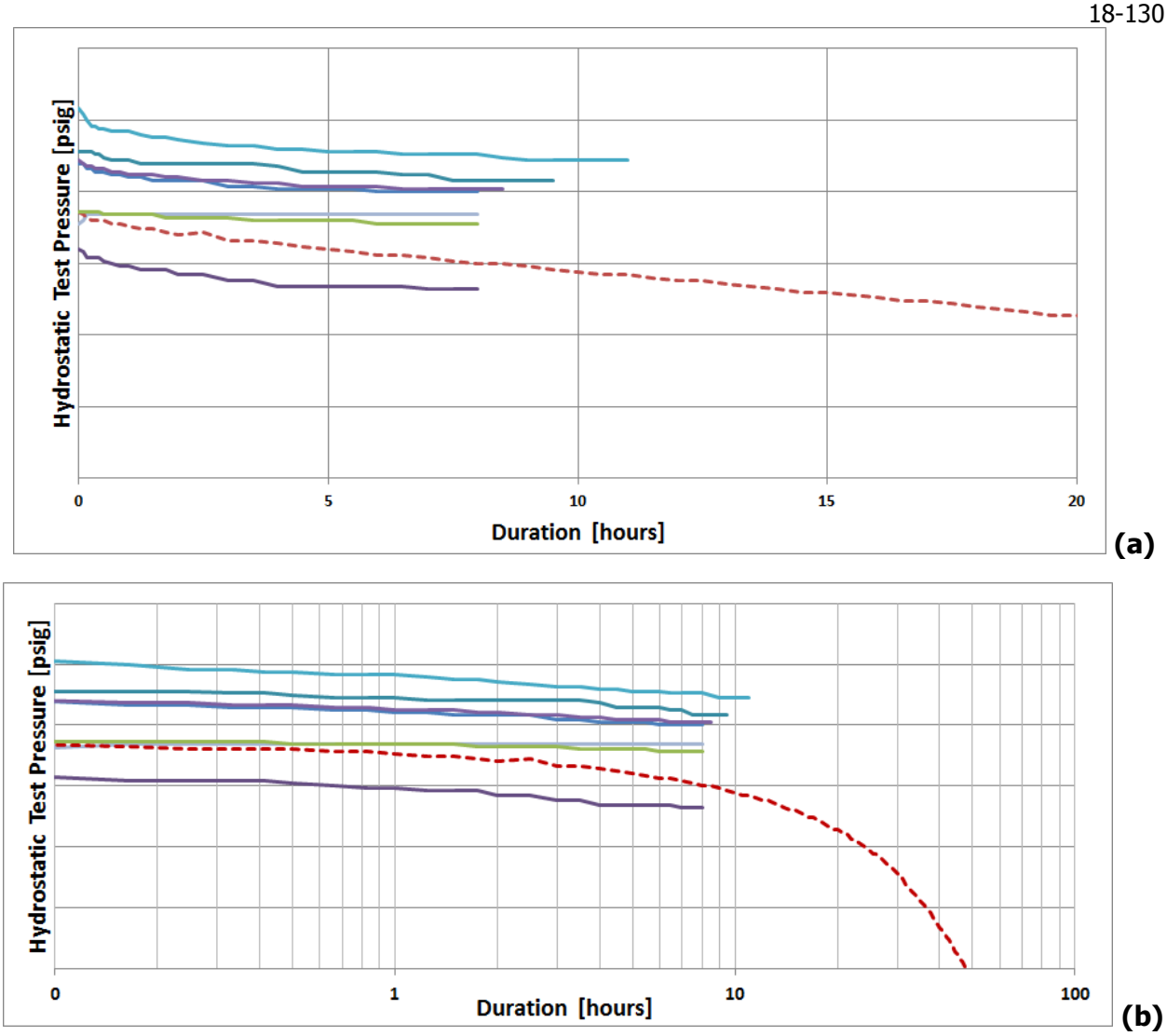


Figure 6. Test Pressure Loss Behavior over Time

Effects of Pipe Yielding and Acceptable Limits on Pipe Expansion

Pipe pressurized above yield stress will expand, permanently deform and eventually fail if pressurization is not stopped once the yield point is observed. In principle there is nothing detrimental about some amount of yielding well short of bursting a sound pipe, because the pipe that is yielding will undergo strain-hardening. Its strength level will increase commensurate with the pressure level reached. Gaging pig results on pipelines where significant yielding had taken place are detailed in Table 5 in Reference [iii]. These data indicated that 300 miles of 30-inch outside diameter (OD) and 36-inch OD X52 pipe tested to 113% of specified minimum yield strength (SMYS) showed less than 0.25% of the pipe was expanded more than 1% (about 100 pipes out of 40,000) and that 50 miles of 36-inch OD X60 pipe tested to 113% of SMYS showed less than 1% of the pipe was expanded more than 1% (about 66 pipes out of 6,600). It is known based on PV plots that the pressurizations of these test

sections were carried out to offset volumes well beyond that which corresponds to the half-slope-limit criterion suggested above. Yet, there is no known indication that any of these pipes have caused problems in the 50 to 60 years since they were installed.

While it is clear from Reference [iii] that some pieces of pipe in active pipelines have been expanded to levels of 1% or more, there is a practical limit to the amount of yielding that should be accepted. If the pipe diameter increases by more than about 1/8-inch (0.4% expansion for a 30-inch OD pipe), and it has to be repaired later in service for any reason by cutting out a cylinder, then it may not be possible to weld a standard-size pipe to the expanded pipe. The half-slope-limit on a PV plot is a reasonable way to assure that few, if any, pieces of pipe attain 0.4% plastic expansion in a pressure test.

Unintended expansion of pipe during pressure testing has occurred in pipe installed in various eras. Tests of the effects of pre-strain or strain history on the ductility properties of steel including line pipe has shown that expansion of 2% and potentially up to 3% of the pipe diameter has little adverse effect on pipeline fracture control parameters and only minor effects on reassessment criteria or intervals. Larger amounts of diameter expansion should be addressed with a comprehensive fitness for service evaluation of these effects if the expanded pipe is to remain in place[iv].

Reassessment

Reassessment of pipeline segments that could affect high-consequence areas (HCA) is required by 49 CFR 195.452 and 49 CFR 192.939. According to paragraph 195.452(j)(2) an operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity[v]. The frequency must be based on an evaluation of risk factors (including, but not limited to, results of the previous integrity assessment, defect type and size that the assessment method can detect and defect growth rate), analysis of the results from previous assessments, the information analysis required by Paragraph 195.452(g) (which considers the potential for damage and the consequence of failure), decisions about remediation, and preventative and mitigative actions. As stipulated in paragraph 195.452(j)(3), an operator must establish 5-year intervals, not to exceed 68 months, for continually assessing the line pipe's integrity[vi]. Additionally, paragraph 195.452(j)(4) states an operator may be able to justify an engineering basis for a longer than 5-year assessment interval on a segment of line pipe[vii] and must notify PHMSA (OPS) 270 days before the end of the 5-year (or less) interval. Paragraph 192.939 provides maximum reassessment intervals for gas pipelines[viii]. The code incorporates ASME B31.8S by reference and maximum reassessment intervals can range from seven to 20 years depending on operating stress level, assessment type, and results.

Reassessment intervals for pipeline segments are supported by the evaluation of pressure test results and execution of engineering critical analysis. Maximum potential flaw sizes that could just-survive the pressure test are estimated utilizing the maximum TPR value achieved (without failure) at the location of analysis. All pipe types present should be included in the analysis, as well as critical locations studied such as station discharge locations, high point elevations, and crossings. Applicable growth, under various degradation mechanisms, is modeled for the assumed just-surviving population of flaws. Time-to-failures are predicted when each modeled flaw type and size extends to a size expected to fail at MAOP or MOP. Predictive time-to failure models can be deterministic or probabilistic. For deterministic model results, reassessment from the date of the pressure test should not exceed the minimum estimated time-to-failure divided by a recommended safety factor of two. For probabilistic model results, reassessment should not exceed an operator defined acceptable level of risk or probability of failure (POF) at the target reassessment time. Target risk thresholds should account for a number of factors including local consequences of failure, uncertainties associated with the assessment method, expected pipeline operation, and expected rates of degradation, among other things.

Recall from the Task 4 report that pressure testing is commonly implemented for the reassessment of longitudinally oriented flaws associated with the pipe seam manufacturing processes. The sections to follow provide guidelines for the execution of a deterministic time-to-failure model for longitudinal seam weld fatigue cracks and outline the necessary steps in reassessment interval determination, which include:

- selection of material property input parameters,
- establishing an initial and final flaw size, and
- modeling growth (in the case of the example to follow, pressure-cycle-fatigue).

Pressure-Cycle-Induced Fatigue Growth Analysis – Deterministic Model Example

A mechanism that can cause time-dependent degradation of seam integrity involves the enlargement of latent seam manufacturing flaws by pressure-cycle-induced fatigue. An operator assessing the need for seam integrity reassessment should consider the possibility that the segment can be affected by this mechanism. The results of a fatigue analysis should be used to decide if and when reassessment is needed.

Guidelines on how to execute a fatigue analysis considering the results of a pressure test, including recommendations on input variables are addressed herein.

Establishing Initial and Final Flaw Sizes

The initial sizes of cracks for which the times to failure are desired can be established by a failure-pressure-versus-flaw-size model, including but not limited to Modified Ln-Sec[ix], PAFFC[x], CorLas™ [xi], API 579 Level II[xii], or Battelle's "Pipe Assess PI™" to define the flaw length and depth combinations that could have just survived the test pressure level. Reference Annex C of API RP 1176 or the PRCI Project PR-218-0540 report, *Pipeline Defect Assessment – A Review & Comparison of Commonly Used Methods*[xiii], for in-depth descriptions of the above listed methods. Normally, nine length and depth combinations with depths ranging from 10% of 90% of the wall thickness are adequate to establish a representative distribution of just-surviving flaws. The final flaw sizes are those length and depth combinations that will fail at the M(A)OP of the pipeline (based on a model such as the Modified Ln-Sec Equation).

Material Toughness

To utilize a failure-pressure-versus-flaw-size model such as the Modified Ln-Sec Equation[2], the user must supply an appropriate value of CVN energy for the material to represent its fracture toughness. The appropriate value of CVN energy is the full-size-Charpy-equivalent upper-shelf energy measured for the pipe body or HAZ material by means of specimen oriented transverse to the axis of the pipe with the notch being oriented such that axial crack propagation will take place. The rationale for using the pipe body or HAZ upper-shelf energy is that the seam related ERW and flash-welded (EFW) flaws that are most often associated with pressure-cycle-induced fatigue crack growth are hook cracks and mismatched plate edges. Both kinds of flaws are located near, but not in, the bondline and are generally located far enough from the bondline such that the relevant material toughness is more like that of the HAZ and pipe body than that of the bondline region. Upper-shelf energy is appropriate rather than the energy level from testing a Charpy specimen at a fixed temperature. This is because the initiation of a failure occurs under quasi-static (low strain-rate) conditions; the high strain rate of the impact test shifts the transition temperature significantly upward. The infrequent exception would be where the Charpy transition temperature is well above the operating temperature plus the temperature shift associated with strain rate effects.

Pipe material properties, including Charpy impact absorbed energy, can be determined from MTRs or destructive testing results where available. If the Charpy energy is unknown, a conservative yet plausible value should be assumed based upon review of pipe vintage, type and past test results. An assumed full-size-equivalent Charpy upper-shelf energy value of 25 ft-lb or greater is often appropriate for a fatigue analysis where pressure test pressure and the

[2] The Modified Ln-Sec Equation is not recommended for modeling failure in brittle pipe material and is not recommended for material having a full-size-Charpy-equivalent upper-shelf energy value of 10 ft-lbs or less.

Modified Ln-Sec Equation are used to establish the initial flaw size. Choosing a value near the high end of the range for typical line pipe materials manufactured in the 1950s and 1960s results in a shorter time to failure (i.e., a more conservative estimate) after a pressure test than if a lower value of energy were to be chosen. The reason is that the higher the Charpy energy is, the larger the initial flaws will be. Of course, the Charpy energy has a similar effect on the final flaw size, but when the flaw approaches failure at the M(A)OP, the steps of crack growth are so large that the failure pressure drops rapidly. At this stage the differences in final crack sizes for two different levels of Charpy energy will only alter the time to failure by the time it takes for a few large pressure cycles to occur. Time to failure is the time necessary for the flaw to grow from the initial to the final size and the effect on crack growth rate from the larger initial flaw size associated with high ductility greatly outweighs the small increase from the larger final flaw size. (The opposite strategy for assuming toughness and strength properties would apply where the time to failure is calculated based on an ILI or NDE sizing of a flaw. In those cases, conservative times to failure are achieved by assuming lower bound material properties.)

Material Strength

Most line pipe is over-strength. Higher material strength enables larger flaws to survive a test pressure compared to pipe material near or at SMYS values. Even though the over-strength material increases the failure pressure, the fact that larger flaws grow more quickly to failure is a more dominant factor in the remaining life determination[xiv]. Thus excess strength reduces the calculated time to failure when the initial flaw size is based on a pressure test.

Flow stress is a critical parameter used in failure prediction models and its value is often estimated as the SMYS plus 10 ksi.[xv] A more accurate representation of flow stress is the average of a material's yield and ultimate strengths. If known, the actual mean flow stress should be considered for each applicable case. Pipe material properties can be determined from MTRs or destructive testing results where available.

Research and destructive testing performed by Kiefner of a few hundred specimens has shown significant variability in yield strength and ultimate tensile strength values from specified minimums, which collectively affect flow stress estimates. The effects of a distribution of flow stress values, including lower bound (lower 5th percentile), mean, and upper bound (upper 95th percentile) values should be considered alongside SMYS and for each analysis case. Table 4 provides the corresponding recommended yield strength input values for use in analysis if the analysis calls for YS as an input but makes adjustments within the calculation to estimate flow stress by adding 10 ksi. Note that Table 4 was developed from the same data set provided and documented in the previously referenced Table 2 and Table 3.

Table 4. Recommended Yield Strength Input Values for Pipelife based on Flow Stress Distributions from Database

Grade	Pipelife Yield Strength Input Values based on Flow Stress distributions, lb/in.^{2} (MPa)		
	Lower 5th Percentile	Mean	Upper 95th Percentile
A/Bessemer/Open Hearth	31,500 (217.18)	39,000 (268.9)	46,000 (317.16)
B	36,500 (251.66)	48,500 (334.4)	60,500 (417.13)
X42	42,500 (293.03)	52,000 (358.53)	61,000 (420.58)
X46	45,000 (310.26)	53,500 (368.87)	62,000 (427.48)
X52	49,500 (341.29)	59,000 (406.79)	68,500 (472.29)
X56	51,000 (351.63)	63,500 (437.82)	76,000 (524)
X60	59,500 (410.24)	68,000 (468.84)	76,500 (527.45)
X65	66,000 (455.05)	71,500 (492.98)	77,000 (530.9)
X70	71,000 (489.53)	79,500 (548.13)	87,500 (603.29)

Pressure Cycle Counting

Recorded pressure cycle data should be collected. A minimum of one year of data should be studied, more if variable operating scenarios have been in effect since the most recent pressure test. Pressure data shall be free of errors and represent past and future pipeline operation. The following is recommended:

- Liquid Pipelines:
  - Data gathering locations include:
    - Each pump station discharge and receipt[3]
    - Intermediate recorder locations
  - Data gathering frequency is:
    - Fixed 1-minute sample interval, or
    - Change of state sample interval (pressure readings are taken when a change in pressure occurs rather than a fixed interval)

[3] Assure the recorded pressure for the receipt location is representative of the mainline (or pipe segment being analyzed) pressure. For example, some pressure monitoring equipment, such as pump suction pressure, may be downstream of a check valve or block valve and not adequately measure mainline pressure during the entire data collection timeframe.

- Gas Pipelines:
  - Data gathering locations include:
    - Each compressor station location
  - Data gathering frequency is:
    - Hourly maximum and hourly minimum, or
    - Change of state sample interval (pressure readings are taken when a change in pressure occurs rather than a fixed interval)

The collected pressure data, representative of pipeline operation, should be collected, annualized and rainflow cycle-counted[xvi] in order to reduce the stochastic signal into cycles that can be used for benchmark cycle analysis and in the fatigue model. If the magnitude, frequency, or both of the actual future pressure cycles differ significantly, then the results of the analysis will be affected. Fatigue crack growth will not occur below a threshold of change in stress-intensity, ΔKth. Acceptable lower bound ΔKth limits include 4% to 8% of SMYS (depending on pipe grade), or 5% of the maximum pressure cycle recorded[xvii]. Conservatively, the lesser of the following two should be disregarded: pressure cycles less than 25 psi or 3% SMYS in magnitude.

Models for Crack Growth Calculations

A "Paris-Law" model[xviii] is a commonly implemented for the calculation of times to failure for cracks that grow by pressure-cycle-induced fatigue. The generic Paris-Law model is:

$$\frac{da}{dN} = C(\Delta K)^n \qquad \textbf{Equation 4}$$

$$\Delta K = C_1 \Delta S \sqrt{\frac{\pi a}{Q}} \qquad \textbf{Equation 5}$$

where:

da/dN is the incremental crack growth per cycle (inches per cycle)
ΔK is the change in stress intensity factor per cycle (psi√inch)
C and n are crack growth rate constants that depend on the material and the environment
C_1 is a constant
ΔS is the change in hoop stress per cycle (psi)
a is the current crack depth (inch)
Q is a function of the depth/length ratio of the crack.

The Miner-Palmgren Linear Cumulative Damage Law is another model for estimating time to failure by fatigue however, it is not recommended as broadly for use as the Paris-Law model.

Instructions on how to conduct fatigue analysis using both the Paris-Law and the Miner-Palmgren Linear Cumulative Damage Law are provided in API RP 1176.

Fatigue Crack-Growth Rate Constants

Crack-growth rate constants may be calculated from the known circumstances of prior failures caused by pressure-cycle-induced fatigue. This requires knowledge of the initial crack size, the crack size at failure, the pressure level at failure, the pressure-cycle history and the time that it took for the crack to grow from its initial size to the size at failure for at least one case of fatigue failure in a particular pipeline. Another possibility arises where examination by electron microscopy reveals steps of crack growth over a significant portion of the fracture surface. In such a case, it may be possible to establish crack growth rate constants by measuring key features on the fracture surface. It is also possible to measure crack growth rates under laboratory conditions using either small-scale compact tension tests or full-scale pipe pressure cycle tests. These options are usually not available. Therefore it is usually necessary to rely on published crack growth rate constants. API 1176 provides a list of sources and applicability for a variety of published rates. Conservative and widely applicable constants are found in API Standard 579-1/ASME FFS-1 *Fitness for Service*, and the ones recommended are $C = 8.61 \times 10^{-19}$ for ΔK in psi√inch units and $n = 3$.

It is worth noting that the stress decision point in Figure 7 and Figure 8, (i.e., ≤30% of SMYS for low priority, ≤40% of SMYS for a test-pressure-to-operating-pressure ratio of 1.5) can be rationalized on the basis of the Paris Law and the crack growth rate constant, n. It is noted from Equation 5 above that the hoop stress range associated with a pressure cycle, ΔS, is proportional to ΔK at any fixed crack size. The crack growth rate, da/dN, as per Equation 4 is proportional to $(\Delta K)^n$. Thus, one can compare the relative effects of different operating stress levels on crack growth by comparing the stress levels raised to the nth power. If we assume that the relative cyclic stress range for a pipeline that is operated at 72% of SMYS is 1, then 1 to the third power (n=3) is 1. If we assume that the relative cyclic stress range for a pipeline that is operated at 30% of SMYS is 30/72 = 0.4167, then 0.4167 to the third power is 0.072. So the crack growth at 72% of SMYS for the case of a full-range cycle is 13.8 times as fast as the crack growth rate at 30% of SMYS. By similar reasoning one can show that the crack growth rate at 72% of SMYS is 5.8 times as fast as the crack growth rate at 40% of SMYS. If one assumes that pressure cycles are at least somewhat proportional to the maximum operating pressure, then it is rational to consider the pipelines operated at stress levels of 30% of SMYS are less likely to exhibit failures associated with pressure-cycle-induced fatigue.

Calculated Times-to-Failure and Reassessment Interval

The procedure for conducting a remaining life assessment for a pipeline in which pressure-cycle-induced fatigue is a possibility is:

- Study MTRs, findings from destructive material testing, or material property distributions to identify either actual strength and toughness properties or estimated ranges of strength and toughness properties.
- Establish initial flaw sizes based on maximum achieved test pressures from the most recent assessment.
- Count pressure cycles for annual representation of service.
- Select appropriate crack growth rate constants.
- Calculate times for the population of flaws to reach a critical size to failure at M(A)OP for all pipe types and critical locations.
- Establish the reassessment interval as the minimum calculated time to failure divided by a recommended safety factor of two.

Longitudinal Seam Weld Failure Susceptibility and Assessment Prioritization

TTO-5, "Low Frequency ERW and Lap-Welded Longitudinal Seam Evaluation"[xix], addressed the possible need for reassessment of seam integrity, and it provided a methodology for establishing reassessment intervals. However, it was written at a time when baseline assessments were either beginning or in progress. This section expands on the procedure for deciding if and when seam reassessment is needed in light of what has been learned through completed baseline assessments and new technology since TTO-5 was written.

A seam integrity reassessment of a segment may be needed after a baseline seam integrity assessment, or an initial assessment may be needed where none was previously conducted if any of the following situations exists or develops:

- The results of the baseline assessment showed that the pipe seams in the segment are susceptible to time-dependent degradation.
- The pressure-cycle aggressiveness has increased significantly.
- A service failure occurs as the result of a seam related defect.
- Investigations of ruptures or leaks caused by seam defects in a prior pressure test indicate that time-dependent growth of a flaw has occurred.
- Investigations of seam anomalies identified through prior ILI reveal evidence of time-dependent growth.
- The results of ILI show that widespread metal loss has occurred on the segment and it is known or suspected that the metal loss is not being successfully mitigated[4].
- The segment is bare or poorly coated[4].

[4] Relevant to the threat identification of SSWC

- The operator has reason to believe that time-dependent seam degradation may be occurring even though none of the above situations exists or has developed.

The above circumstances indicate the need for reassessment at the interval required by 49 CFR 195.452 and 192.939. A pipeline operator should consider that pressure-cycle-induced fatigue can lead to failures eventually in any hazardous liquid or gas pipeline even if the pressure cycles are judged to be moderate or light. This includes pipelines comprised of HF-ERW pipe (particularly older-vintage) and EFW pipe as well as LF-ERW pipe and direct current (DC) ERW pipe. Additionally, flash-welded pipe, LF-ERW pipe, DC-ERW pipe and older-vintage high-frequency-welded ERW pipe are also susceptible to selective seam weld corrosion (SSWC).

As part of an effort to determine if and when a seam integrity reassessment is needed, the operator should attempt to identify the cause or causes of time-dependent seam degradation. In this respect, it is important to investigate any seam related test ruptures or leaks that occur during any pressure test of the segment as well as any seam related service failures to determine the root cause(s). In addition, the operator should consider the degree of risk from the known causes of seam related, time-dependent degradation and determine the appropriate reassessment intervals based on the guidelines presented.

Applicable Pipe Types

These recommendations are applicable to any pipe having a longitudinal seam weld:

- lap-welded
- direct current (DC) ERW
- low-frequency (LF) ERW
- high-frequency (HF) ERW
- flash-welded (EFW)
- single-submerged arc welded (SSAW)
- double-submerged arc welded (DSAW)

Older-vintage HF-ERW pipe is pipe made from open-hearth, ingot-cast skelp where the propensity for hook cracks is essentially the same as it was for LF-ERW. By the early 1980s, most ERW pipe was made from basic-oxygen, continuous-cast skelp where the propensity for hook cracks is greatly reduced. Moreover, by the early 1980s, the manufacturers were employing much better seam inspection technology. Therefore, these more modern materials and inspection practices do not raise the same concerns that the older materials raised regarding hook cracks.

Weld metal cracks and toe cracks can form at either the outside surface or inside surface of the longitudinal weld during the manufacture of submerged arc welded (SAW) pipe. Rail shipment fatigue cracks can also form at the toe of SAW welds. These flaws, if small enough, can survive

the commissioning pressure test and possibly enlarge in service due to pressure-cycle fatigue. According to TTO-5, the analysis of fatigue crack-growth life for such flaws is essentially similar to that for hook cracks in ERW seams.

Lap-welded pipe should be considered separately from the other types of pipe because it is generally used in systems operated at relatively low hoop stress levels and because there is little or no evidence that seam related service failures in lap-welded pipe arise from time-dependent causes.

Pressure Cycle Aggressiveness Determination

Collected pressure data, representative of pipeline operation, should be annualized and rainflow cycle-counted[xx] in order to reduce the stochastic signal into cycles that can be used for benchmark cycle analysis and in the fatigue model (as discussed in the fatigue analysis example). If the magnitude, frequency, or both of the actual future pressure cycles differ significantly, then the results of the analysis will be affected. Fatigue crack growth will not occur below a threshold of change in stress-intensity, ΔKth. Acceptable lower bound ΔKth limits include 4% to 8% of SMYS (depending on pipe grade), or 5% of the maximum pressure cycle recorded[xxi]. The lesser of the following two is recommended for use to determine a conservative threshold: pressure cycles less than 25 psi or 3% SMYS in magnitude.

A comparison of the pressure cycles that occur on the pipeline and benchmark pressure spectra should be performed. The benchmark pressure spectra were calculated from analysis of actual pipelines in which fatigue failures occurred. The comparison of these cycles to the actual cycles that occur on a pipeline can be used to determine the relative aggressiveness of the pressure cycles. The cycle aggressiveness can be determined by one of two methods, both adapted from TTO-5:

- Method 1: Determine relative aggressiveness by comparing the minimum estimated time to failure using actual pressure spectra to the estimated time to failure using benchmark aggressiveness pressure spectra, or
- Method 2: Compare an equivalent cycle annual cycle count[xxii] determined from the actual pressure spectra to the equivalent cycle annual cycle count of the benchmark cycle spectra.

The following instructions apply when implementing Method 2. Table 5 is adapted from TTO-5 and provides annual benchmark cycle counts for Very Aggressive, Aggressive, Moderate and Light cycles. Using Equation 6, convert the number of annual cycles in each percent SMYS range to equivalent P_{eq} cycles. Then sum each category to determine the number of total equivalent P_{eq} cycles. The annual total equivalent P_{eq} cycles are then compared to the annual

benchmark cycles to determine the resulting aggressiveness. Table 5 illustrates a P_{eq} equal to 72% SMYS.

$$\sum n_i \left(\frac{P_i}{P_{eq}} \right)^3 \qquad \textbf{Equation 6}$$

where

n_i is the number of cycles occurring within the stress range
P_i is the highest level of pressure within the stress range (psi)
P_{eq} is the pressure value equal to a predetermined value (psi)

Table 5. Annual Benchmark Cycle Counts

Pressure Cycle Size	Very Aggressive	Aggressive	Moderate	Light
66 - 72% SMYS	20	4	1	0
56 - 65% SMYS	40	8	2	0
46 - 55% SMYS	100	25	10	0
36 - 45% SMYS	500	125	50	25
26 - 35% SMYS	1000	250	100	50
25 psi - 25% SMYS	2000	500	200	100
0 - 25 psi	0	0	0	0
Total Equivalent 72% Cycles	415	101	40	16

An example of how to determine total equivalent 72% SMYS cycles using 5% SMYS bin ranges is provided in Appendix B.

Seam Weld Threat Prioritization

The seam weld threat prioritization procedure was primarily developed from the flow chart and concepts outlined in Annex B of API 1176. There are a few adjustments that add some clarification and conservatism to the prioritization result. Most notably the rearrangement of the question related to in-service seam weld failures to the initial decision box, thereby removing the automatic default of pipelines operating at an MOP less than 30% SMYS to a low priority categorization.

A pipeline segment is either categorized as Low, Medium, or High priority for the assessment of seam weld defects based on:

- seam type,
- year of manufacture,

- failure history,
- operating stress level,
- test pressure levels, coating condition and cathodic protection (CP) effectiveness, and
- operational pressure cycle aggressiveness.

ERW, EFW, and SAW pipe

Figure 7 is the seam prioritization flowchart for pipeline segments containing ERW and EFW, pipe. Figure 8 is the seam prioritization flowchart for pipeline segments containing SAW pipe. A pipeline segment will be categorized as Low, Medium, or High priority for seam weld threats. The primary difference between considerations for ERW and EFW and considerations for SAW is SSWC considerations for ERW pipe only and transit fatigue considerations for SAW pipe only.

Pressure Cycle Induced Fatigue

Pressure cycles in the operation of a pipeline result from changes in throughput. These changes may result from starting or stopping one or more pumps on the system, from a pump station coming on or going off line, from changes in batch density or viscosity, or from closing or opening of valves. In any liquid pipeline, even one with moderate or light cycles, the pressure cycles could eventually cause a manufacturing imperfection to grow to a size that will fail in service. For gas pipelines, pressure cycles are not typically significant enough to support fatigue growth. However, it is possible for fatigue crack growth to occur on a gas pipeline and the likelihood should be analyzed.

The threat of failure from the growth of a seam flaw by pressure-cycle-induced fatigue exists and needs to be addressed by means of periodic seam reassessment if:

- A prior service failure has resulted from or is suspected to have resulted from the growth of a seam flaw by pressure-cycle-induced fatigue.
- Examination of a prior pressure test seam failure or a seam anomaly detected by ILI revealed evidence of pressure-cycle-induced fatigue crack growth.
- A pressure-cycle-fatigue analysis shows that possibly remaining flaws whose sizes have been determined by either a pressure test or an ILI could grow to failure at the M(A)OP within the conceivable life of the pipeline.

Selective Seam Weld Corrosion

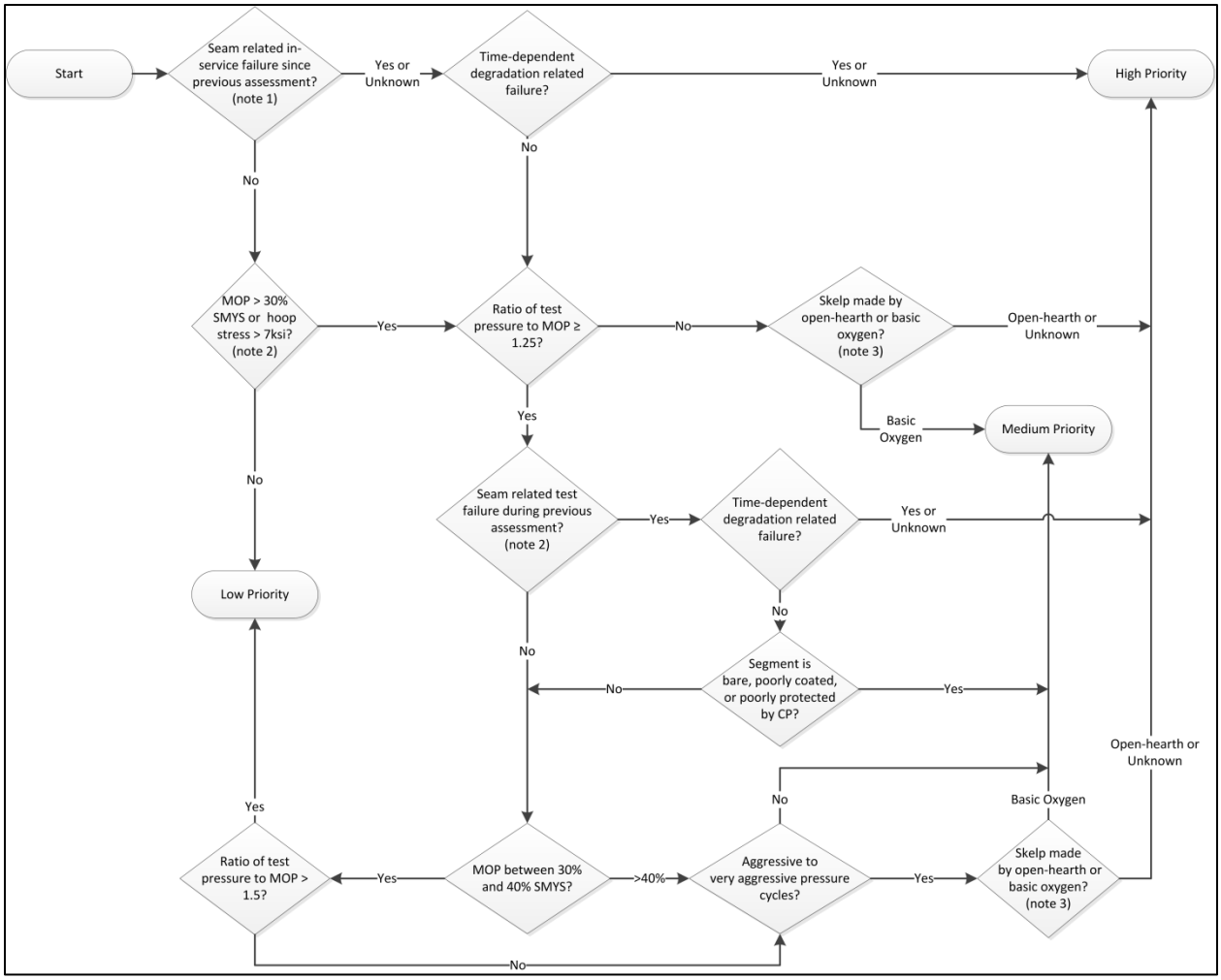
SSWC, also called grooving corrosion, is a phenomenon associated with increased susceptibility to corrosion in the vicinity of the ERW bondline. This phenomenon has been observed in older-vintage HF-ERW pipe and EFW pipe as well as in LF-ERW and DC-ERW pipe. If the pipe is affected by corrosion-caused metal loss, the material near the bondline may corrode at a higher rate than that of the surrounding base metal. The result is a groove of deeper metal loss typically centered on the bondline. The groove creates a crack-like condition and becomes

enlarged in a material that has very low resistance to crack-like flaws in the presence of hoop stress. It would be imprudent to assess the metal loss in the seam using typical corrosion assessment models that are based on the assumption that the corrosion will fail by plastic collapse. The ratio of the depth of corrosion in the bondline to the depth of corrosion in the adjacent base metal is referred to as the "grooving" ratio. Grooving ratios between 2 and 4 are commonly observed.

The threat of failure from SSWC exists and needs to be addressed by means of periodic seam reassessment if:

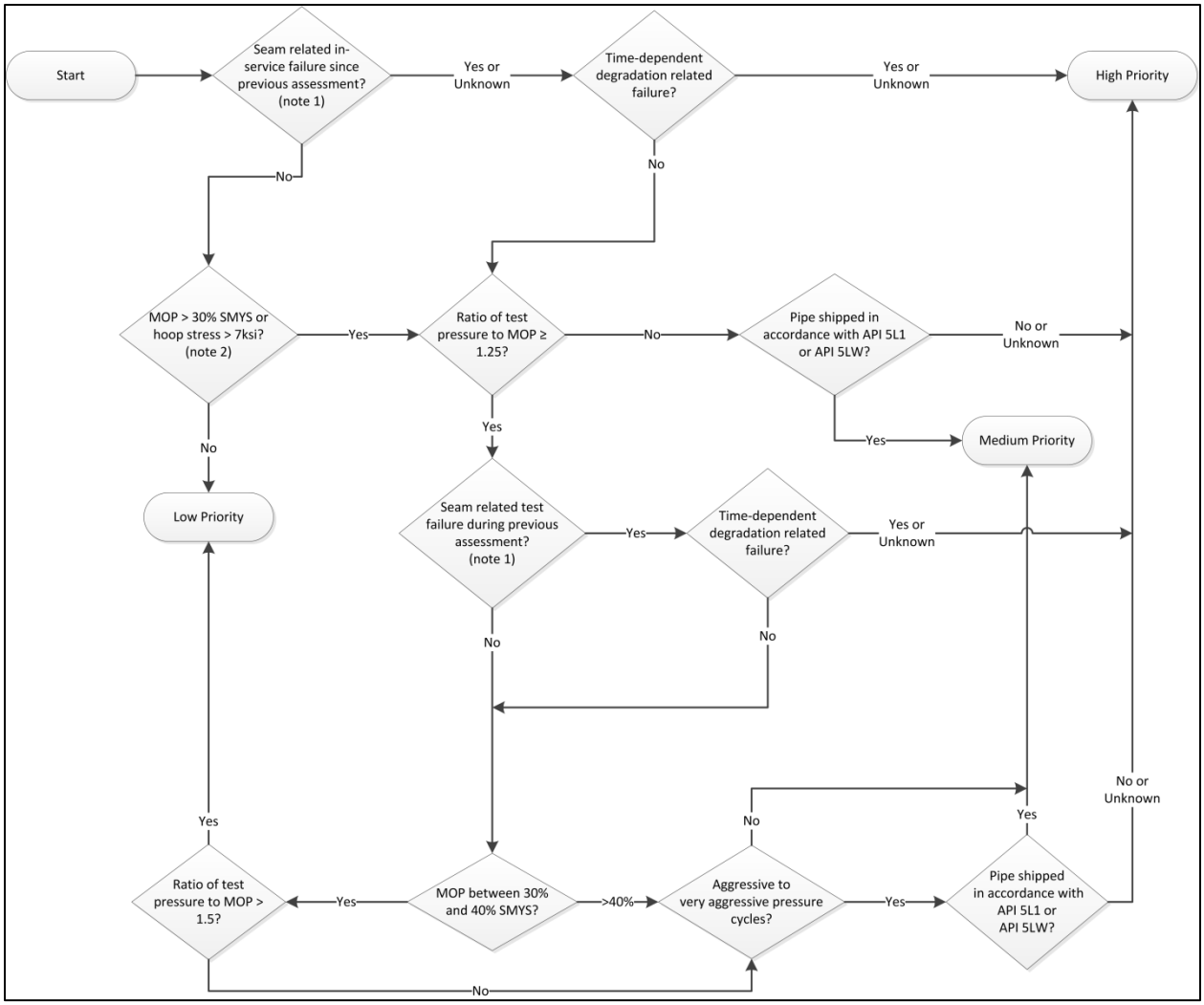
- A prior service failure has resulted from or is suspected to have resulted from SSWC.
- Examination of a prior pressure test seam rupture or leak or of a seam anomaly detected by ILI reveals evidence of selective seam weld corrosion.

Also, data gathering to determine if SSWC conditions exist should be performed if a segment is bare or known to have poorly functioning coating and to have been operated for periods of time with inadequate CP.



Note 1: Seam related in-service failure, leak or rupture mode
Note 2: M(A)OP greater than 30% SMYS applies for ductile material or the consideration is for systems operating to pressures that induce a hoop stress greater than 7 ksi for brittle material.
Note 3: A basic oxygen process is where excess carbon and other impurities are burnt out of pig iron to produce steel. Compared to previous processes (i.e. open hearth), its main advantage was that it did not expose the steel to excessive nitrogen, which would cause the steel to become brittle. The process used may be determined from historical records of pipe manufacturers.

Figure 7. ERW and EFW Pipe Seam Prioritization Flowchart



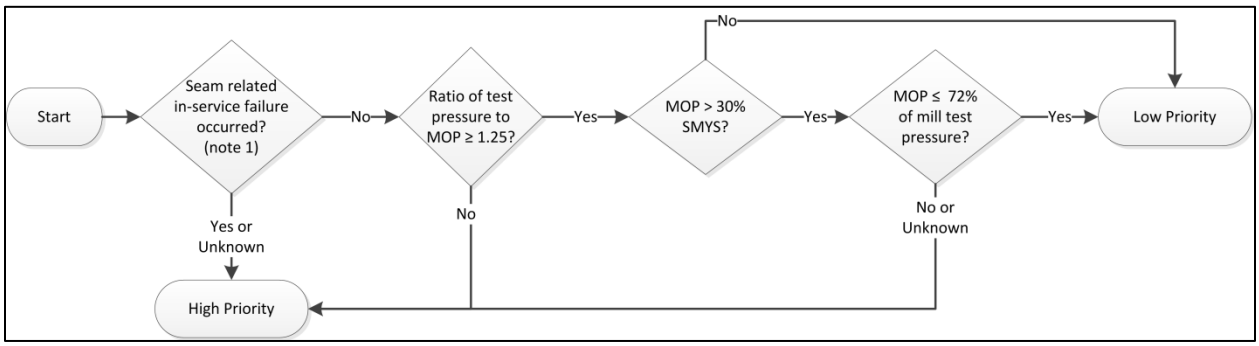
Note 1: Seam related in-service failure, leak or rupture mode.
Note 2: M(A)OP greater than 30% SMYS applies for ductile material or the consideration is for systems operating to pressures that induce a hoop stress greater than 7 ksi for brittle material.

Figure 8. SAW Pipe Seam Prioritization Flowchart

Lap-welded Pipe

Figure 9 is the seam prioritization flowchart for pipeline segments containing lap-welded pipe. A pipeline segment will be categorized as Low or High priority for seam weld threats. The flowchart for lap-welded pipe is essentially the same as the one given in TTO-5. TTO-5 provided criteria for determining whether or not a baseline assessment was needed, but it did not provide a means to determine if or when a reassessment of a lap-welded segment might be needed. The reason why no attempt was made to address reassessment of lap-welded pipe is that time-dependent degradation mechanisms are not well-defined for lap-welded pipe, making it difficult to establish a remaining life for a given segment. This problem has not been resolved. Instead, if the pipeline was subjected to a baseline assessment based on TTO-5, the question of whether or not it requires reassessment should be based on the causes, numbers,

and test failure pressure levels associated with failures during a baseline pressure test. If it was originally determined that a baseline assessment was not needed, the same flow chart below can be utilized for the determination of Low or High priority.



Note 1: Seam related in-service failure, leak or rupture mode.

Figure 9. Lap-welded Pipe Seam Prioritization Flowchart

Reevaluation Schedule Procedure

Criteria for recognizing when it would be prudent to add a segment from the standpoint of seam integrity assessment are as follow. The criteria include the occurrence of a seam related service failure, the occurrence of a pressure test failure in which a seam related flaw has been found to have grown in service, the discovery of an injurious seam anomaly through a form of ILI not intended primarily for seam anomaly detection, an increase in pressure-cycle aggressiveness, and notification of a seam problem because of occurrences in other pipelines. Examples of where it can be anticipated that such situations could arise include EFW pipe, early-generation HF-ERW pipe, segments that were determined to be "not susceptible" via the baseline assessment criteria of TTO-5 but have relatively short calculated times to failure, or segments for which evidence of a transportation fatigue crack problem exists.

Criteria for recognizing when it would be acceptable to eliminate a segment from reassessment for seam integrity purposes are as follow. The criteria include ILI findings that indicate no significant seam anomalies exist and that a reduced operating pressure reduces the risk for fatigue growth or at least significantly lengthens the reassessment interval. One finding that does not guarantee the absence of a seam integrity problem is the absence of service or test failures from seam related defects. The absence of failures up to a certain point in time is no guarantee that failures are not impending at a later time.

Inputs to the seam weld threat prioritization flowcharts and the remaining life calculations should be reevaluated on a regularly scheduled basis to determine if reassessment decisions require updating. Following the guidelines established in API RP 1176, the reevaluation schedule is established as:

- Annually for High priority pipeline segments
- Once every 3 years for Medium priority pipeline segments
- Once every 5 years for Low priority pipeline segments

In-line Inspection Verification

Effectiveness of ILI should be measured in terms of the kinds and sizes of flaws that were detected and the probability that some were not detected. ILI may not be an effective tool if defects fail in service or during pressure testing that were not detected by the tools. It may be necessary to employ both ILI and pressure testing to verify the reliability of the ILI tools. When an ILI tool is shown to be reliable from the standpoint of accurately locating and characterizing flaws, then the use of the ILI tool will always be preferable to pressure testing.

API RP 1176 offers the following on using pressure testing for ILI verification[xxiii]:

> "When the verification of crack features by excavation results does not sufficiently correlate with the ILI for detection or severity, pressure testing, possibly of a segment or segments of a pipeline, could be required to verify the possible population of remaining cracks. Verification by pressure test is demonstrated when a pipeline segment that could not be verified by excavation successfully passes a hydrostatic test without any failures. If failures occur, the testing of additional segments should be considered depending on the failure cause (i.e., could be unrelated to cracking). In some cases, an operator may elect to perform a verification hydrostatic test on only a portion of a line section inspected by ILI. When only a portion of the line is tested this way, the test section should be representative of the entire segment regarding crack type, growth mechanism, and pipe properties. If one hydrostatic test section is used to verify multiple ILI runs, then the operator must ensure that the critical characteristics of each ILI run (such as vendor, technology, and run media) are similar so that the results are not affected."

While API RP 1176 is specific to crack threats, the same logic for ILI verification by means of pressure testing could be adopted for other threats, such as SSWC.

If no one ILI technology is capable of detecting all possible threats, or validation of the ILI tool is desired, a combination of ILI and pressure testing should be considered if:

- Operator has limited experience with the selected ILI technology and an applicable industry correlation data set substantiating the tool performance is not available;
- Only magnetic ILI tools are selected;

- Operator is assisting with the development of new ILI technologies or seeking to demonstrate the reliability of an ILI technology where operator experience, history, cutouts or other data are not available to confirm the results;
- When the verification results of features by excavation do not sufficiently correlate with the ILI report for detection or severity, pressure testing may be needed to verify the population of remaining features in the line. If pressure testing is needed to assist in verifying the population of remaining features in the line, the entire pipeline may not need to be tested. Rather, a segment or segments of the pipeline with suspected flaws that span the potential flaw population may be selected;
- There is the possibility that a significant number of flaws would fail a pressure test, and ILI can help identify flaws for repair prior to pressure testing. In the process of repairing flaws found by ILI, data should be collected in the field to estimate the size of flaws that were identified by ILI and any additional flaws not detected by ILI at the same excavation site to provide data on the size of flaws that could remain after the pressure test. This information is useful to validate the ILI run and to determine reassessment intervals.

Determining the order in which multiple assessment methods are applied can have an important impact on the post-assessment safety factor and should consider a number of factors:

Pressure testing should be considered first when the following conditions are present:

- The pipeline does not have a documented pressure test in accordance with Title 49 CFR 195 Subpart E or 192 Subpart J;
- The outcome of the ILI assessment may not be sufficient to achieve the desired safety factor or reassessment interval as determined by using the tool specifications, tolerances, and growth rates;
- ILI cannot identify critical size flaws of the expected types; or
- There is a need to detect cracks with ILI that survived, were potentially initiated by, or grew during the pressure test.

ILI should be considered first when the following conditions are present:

- There is a need to identify and remediate flaws that may fail during a pressure test.
- There is a need to document the performance of a technology demonstrating all flaws that would fail a pressure test were identified in the ILI.
- There is a need to demonstrate the capability of a new ILI technology or existing ILI technology where the sizing capability and reliability of the tool are actively being improved.

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APPENDIX A – EXAMPLE METALLURGICAL LABORATORY FAILURE EXAMINATION PROTOCOL

Introduction

The objective of a metallurgical analysis of a line pipe failure is to assign one or more probable causes for the failure. The failure analysis may identify issues that must be remediated to ensure the integrity of other sections of the failed line pipe as well as other pipeline segments with similar characteristics (i.e. pipe manufacturer, seam type, grade, other specifications, coating type, and environmental conditions). This protocol specifically addresses the failure analysis of line pipe.

A typical sequence of analysis is discussed in this appendix. Engineering decisions must be made during any failure analysis, and the results of each step dictate the next procedure to be performed. The need for other tests to be performed is a determination that should be made during the course of the investigation; and, in some instances additional samples of pipe from adjacent joints may be necessary for testing. In this instance, the proposed test plan should be modified to reflect these changes.

Background Information

Background information should be collected on the pipeline operating history, pipeline attributes, pipe specifications, operating pressure, and failure pressure. The operator should supply this background information to the failure investigator. Additional background information may be requested from the operator as the need arises during the investigation.

Visual and Nondestructive Examination

1. Photographically document the pipe in the "as-received" condition before initiating the metallurgical analysis. Documentation may include the following:
    a. Fracture area and surface
    b. Seams
    c. Girth welds
    d. Coating condition
    e. Anomalies
    f. Manufacturing flaws or defects
    g. Pitting and/or evidence of corrosion on internal and external pipe surfaces
2. Perform visual examination of the internal and external pipe surfaces in the "as-received" condition, and document any anomalies that may be present in the pipe such as the following:
    a. Cracks
    b. Crevices
    c. Dents
    d. Bends
    e. Buckles
    f. Gouges
    g. Manufacturing defects

   h. Wrinkles, tents or damage to the coating
   i. Pitting and/or evidence of corrosion on internal and external pipe surfaces
   j. Presence of corrosion products and/or deposits
   k. Describe coating, and coating damage (disbonding) if any, in the vicinity of fracture origin and at other locations in the failed pipe sample
   l. Describe any internal coating or linings (if used)
   m. Examine the pipe sample surface for evidence of stress corrosion cracking
   n. Examine for evidence of arc burns, excessive grinding around the surface area near the crack
   o. If corrosion is evident, collect corrosion products for analysis
3. Collect solid and liquid samples, if present, from the pipe surface, and conduct elemental analyses and microbial tests on these samples, as appropriate. Examples of samples that may be collected are, but not limited to, the following:
   a. Liquid accumulated underneath the coating. If not enough liquid is present for collection, consider using pH paper to characterize pH.
   b. Corrosion products and/or deposits from the internal and external surfaces of pipe surface
   c. Soil adhering to the pipe
4. If coating is to be removed, it should be removed in a manner that will not be injurious to the pipe. Photographically document and visually inspect the pipe again following coating removal (see 1. and 2. above for guidance). Note any disbondment or possible adhesion problems with coating.
5. It may be necessary to inspect the failed section of pipe for cracking, SCC, or any other condition that could affect the long term integrity of the pipeline using nondestructive testing techniques. The surfaces of the pipe surrounding the rupture should be cleaned with an appropriate non-abrasive cleaner and subsequently inspected using a wet black-on-white, magnetic particle inspection method. This magnetic particle inspection method is preferred because internal and external defects can be readily identified. Other nondestructive examination techniques such as Fluorescent Penetrant, Radiographic, Eddy-Current, Ultrasonic Inspection, and Alternating Current Potential Drop may also be used.
6. The physical location of all samples to be removed from the pipe for examination and metallurgical analysis should be documented such that all relevant features are visible (graphically and/or photographically).

Physical Measurements

1. Measure the diameter and wall thickness on undisturbed areas of the pipe to confirm the background information provided.
2. Measure the diameter and wall thickness at selected locations to determine actual values at these selected locations. Measure and record the diameter and wall thickness of the pipe at each end of each sample. (Wall thickness should be determined based upon four measurements taken 90 degrees apart.)
3. Verify roundness and geometry of pipe at the extremities and closer to the failed surface.
4. Measure the wall thickness around fracture surfaces and any damaged areas. If corrosion is identified near or around the fracture surfaces, a "corrosion map" should be

produced detailing the extent of the corrosion on the pipe surfaces and the pipe wall thicknesses in those areas. This information may be needed to support remaining strength calculations, if required.

5. Align the pipe samples to conform to the pre-fracture bend geometry.
6. Determine and mark the location of the longitudinal seam weld, if present and visible, at each end of each sample.
7. Determine whether or not any part of each rupture falls within the longitudinal seam weld zone, if a seam weld is present and visible.
8. Measure and record the length of each sample.
9. Record any markings detected on the inside or outside surfaces of the pipes.
10. Measure rupture lengths tip-to-tip. (Not applicable for transverse fractures that sever the pipeline).
11. Measure the shortest circumferential distance from each fracture origin to the nearest longitudinal seam weld.
12. Measure the axial distance from each fracture origin to the nearest girth weld, if any.
13. Map wall thickness of each sample within 12 inches upstream and downstream of each rupture origin. Measurements will be taken on a 2-inch square grid pattern that is centered on the fracture origin and that encompasses 100% of the pipe circumference at each origin.
14. Determine depths of cracks using direct exploration (grinding), shear wave ultrasonic testing (UT), Alternating Current Potential Drop (ACPD) or other suitable methods.

Attachment 2 provides a worksheet for documenting physical measurements.

Corrosion Examination

Surface deposits and residues associated with the fracture area and adjacent areas should be collected and analyzed to characterize and determine the origin of the deposits. Attachment 2 provides a worksheet for documenting chemical analysis results of corrosion products.

Based on the results of the visual, nondestructive, and metallographic examinations, the presence of corrosion should be documented, and the type and characteristics of any corrosion present should be evaluated. Remaining strength calculations (such as RSTRENG/ASME B31G) may be performed on corroded areas to support the failure investigation.

If an ILI tool has inspected the failure site in the past, investigation of the ILI log and report can provide information relevant to corrosion growth rate (CGR). The operator may not have this information immediately available but it may be desirable to do this research. In the case of finding the anomaly present in the past ILI report, it is important to understand the operator's excavation criteria in effect at the time of the ILI and the application of an effective area method (i.e. RSTRENG) and anomaly interaction criteria.

Fractographic Examination

1. Visually examine the fracture surfaces in detail to identify the characteristics of the fracture, the nature of the original defect, and the failure initiation point(s). It may become necessary to open the fracture surface in order to conduct part of the examination, and a suitable technique that is dependent upon the particular circumstances of the failure should be used to open the fracture surface.
2. Clean samples in an appropriate manner (Alconox® solution) to remove loose rust, scale, etc. as necessary.
3. Utilize a suitable method to thoroughly document the fracture surface including dimensional documentation. Suitable methods to document the fracture surface include, but are not limited to, the following:
    d. Foil method
    e. Photographs of macroscopic examination
4. Remove selected fractographic samples as necessary for detailed microscopic examination using optical or scanning electron microscope. Examine and document the fracture surface morphology. When chevron marks are present on the fracture surface, they typically point back towards the fracture origin in steels with an ultimate tensile strength of 60,000 psi and less. It is important to be able to characterize the fracture surface morphology, and fractures can be classified into four groups on a macroscopic scale, as follows:
    a. Ductile fractures
    b. Brittle fractures
    c. Fatigue fractures
    d. Fractures resulting from combined effects of stress and environment
    e. Under low magnification under transmitted light microscopy (TLM), observe if there is evidence of fatigue, and ridges to indicate application of high pressure, such as due to hydrostatic testing.

Metallographic Examination

1. Identify metallographic sample origin (sample identification, location, orientation, etc.), perform metallographic evaluation, and take representative photomicrographs. Areas of particular concern are:
    a. At or near the fracture origin
    b. Fracture surfaces
    c. Weld seams
    d. Anomalies
    e. Areas with indications of defects or cracks identified through visual and/or non-destructive testing
    f. Areas exhibiting "typical" microstructures of the base metal, weld metal, and HAZ
2. Perform micro-hardness profiles at appropriate locations such as the following:
    a. At or near the fracture origin
    b. Weld seams
3. Metallographic samples should be examined to characterize and validate any appropriate issues specific to the failure such as:
    a. Pipe specification, grade, and heat treatment
    b. Weld seam in area of fracture

c. Weld seam in un-affected area
d. Corrosion
e. Indications of outside force damage

Mechanical Properties

Testing should be performed to determine the mechanical properties of the pipe and any appurtenances. Mechanical properties of test specimens should not be taken from areas of the pipe that have been plastically deformed as a result of the failure. These mechanical tests should at least include the following:

- Tensile testing
- Toughness measurements (such as CVN testing)
- Chemical analysis

Attachment 2 provides a worksheet for documenting mechanical tests performed and a worksheet for documenting the chemical analysis tests performed on the pipe steel.

Tensile Testing

Tensile test specimens should be prepared and tested in accordance with ASTM A370 (Mechanical Testing of Steel Products) for the pipe base metal and weld seams to measure yield strength, ultimate tensile strength, and elongation. The pipe base metal should, at a minimum, be tested in the transverse direction, and weld seam specimens should be taken across the weld seam.

Charpy V-notch Impact Testing

When CVN Impact Testing is determined to be necessary, the CVN specimens should be prepared and tested in accordance with ASTM E23 (Notched Bar Impact Testing of Metallic Materials) to determine the toughness characteristics of the pipe in the L-T (transverse) direction. In some cases (depending on pipe size and wall thickness) it may be necessary to use sub-size CVN specimens, and these results should be corrected back to full sized specimen values. Results from CVN testing may be reported in some or all of the following forms depending on the testing results:

- Upper-Shelf Energy (in ft-lbs)
- Lower-Shelf Energy (in ft-lbs)
- Ductile-to-Brittle Transition Temperature (in °F) determined from graphical representation of testing results at the midpoint of the best-fit curve
- Test Temperature corresponding to 15 ft-lbs of absorbed impact energy

- Fracture Appearance Transition Temperature (in °F) corresponding to 50% and 80% shear
- Lateral expansion (to measure notch toughness)

In some steels it may be difficult to measure percent shear because of "woody" fracture surfaces. In these cases it would be more appropriate to use lateral expansion and absorbed energy measurements to obtain a more accurate transition temperature.

Chemical Analysis

The chemical composition of the pipe material should be determined using an appropriate method to validate the pipe specification and grade, as well as, to determine its carbon equivalent (for weldability issues). Spectrochemical methods (i.e. optical emission) are usually employed to determine steel chemical compositions. Wet chemical methods may also be used.

Energy dispersive spectroscopy (EDS) and either x-ray diffraction (XRD) or x-ray photoelectron spectroscopy (XPS) analyses may be used to determine elements and compounds present in surface deposits that were collected during the visual examination.

Attachment 1 – Evidence Custody Transfer Control Procedures

PURPOSE:
To provide guidance for preserving and controlling evidence.

SECTIONS:
1. Gathering Documentation
2. Controlling Evidence

SECTION 1 - Gathering Documentation

1. Note: When the investigator obtains documents from companies or private entities, he or she should request that the company or private entity mark all information that it believes contains trade secrets or confidential business information (CBI).
2. Obtain documentation requests from the investigators.
3. Transmit the request.
4. Assign an easily comprehensible tracking number to the documentation request.
5. Record documentation requested in the Evidence Collection List.
6. If the documentation is not received by the time indicated on the request form, consult with the requesting investigator to determine whether he or she still needs the document.
7. If the investigator still needs the documentation, consult with PHMSA to determine what will be needed to obtain it (e.g. a subpoena).
8. Once the documentation is received and logged, give it to the requesting investigator.
9. A procedure should be included to obtain names and contact information of all witnesses directly related to the incident.

SECTION 2 - Controlling Evidence

1. Assign an information type code to the evidence or document and apply it to the evidence. Coordinate with tracking number.
2. Obtain the evidence and any additional information or notes regarding the evidence from the investigator.
3. Date stamp the evidence.
4. Generate an Evidence Control Form and complete an Evidence Control Form entry for the information or evidence.
5. Attach the Evidence Control Form to the physical evidence/notes, if available.
6. Complete a Master Evidence Log entry for the new evidence.
7. File the Evidence Control Form according to the information type code and securely store it.
8. Lock the room and/or file cabinet in which controlled information or evidence is stored when you are not physically present.
9. Ensure that computer-based information or evidence is password-protected.
10. Sign-out evidence into/from the locked storage area.
11. Maintain the evidence in your immediate possession at all times when it is removed from the locked storage area.

Evidence Tag Example

Evidence and Custody Transfer Tag	
Incident Type:	
Tracking No.:	
Date Collected:	
Collected By:	
Location:	
Operator:	
System:	
Disposition: Where the evidence is to be taken and by whom (e.g.; origin; destination; shipper). As evidence custody is transferred, each receiver shall sign form and identify their agency.	Received From: Received By: Date: Time: Received From: Received By: Date: Time:
Item Description and Notes	

Evidence Collection List Example

Priority	Description	Information Type Code	Owner	Requested?
Notes and Comments				

Evidence Control Form Example

Evidence Identification				
Tracking Number	Date Received	Item	Description	Storage Location
Action Log				
Date	Action (e.g. checked out, returned, shipped)	Person/Organization	Current Location	Notes

Master Evidence Log

PHMSA Tracking #	Supplying Organization's Tracking #	Date Received	Item	Description	Received by:	Received From:	Notes:

Attachment 2 – Metallurgical Testing Worksheets

PURPOSE:
To provide sample worksheets for documenting testing that is performed in support of the metallurgical analysis.

SECTIONS:

1. Mechanical Testing worksheet
2. Fracture Sketch and Physical Measurements worksheet
3. Chemical Analysis worksheet
4. Metallographic Specimens and Photograph worksheet

SECTION 1 – Mechanical Testing Worksheet

Test Locations: (e.g.; specific segment of pipe; location; comments)	

Table 1 **Transverse Pipe Body Tensile Test Results**			
Test Location	Yield Strength (PSI)	Tensile Strength (PSI)	% Elongation in 2”

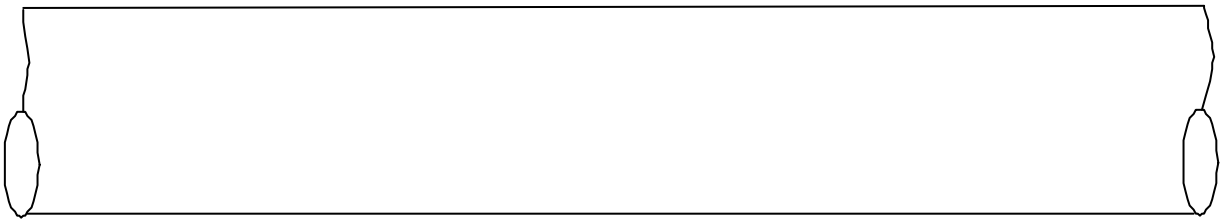
Table 2 **Transverse Weld Tensile Test Results**			
Test Location	Tensile Strength (PSI)	% Elongation in 2”	Fracture Location

Table 3 **Transverse Pipe Body Charpy Tests** **Specimen Size - ____ mm x 10 mm**				
Test Temperature (° F)	Absorbed Energy (ft-lbs)	Absorbed Energy adjusted to normal size Specimen (ft-lbs)	Lateral Expansion (mils)	% Shear

Table 4 **Transverse Weld & HAZ Charpy Tests** **Specimen Size - ____ mm x 10 mm**				
Test Temperature (° F)	Absorbed Energy (ft-lbs)	Absorbed Energy adjusted to normal size Specimen (ft-lbs)	Lateral Expansion (mils)	% Shear

SECTION 2 – Fracture Sketch and Measurements Worksheet

Flow →



Notes:

_____

_____

_____

Longitudinal Length (in):		
Max. Opening Width (in):		
Long Seam Position (O'clock):		
OD at Pipe End (0º-180º):		
OD at Pipe End (90º-270º):		

Wall Thickness Survey at Pipe Ends		
Circumferential Position	Upstream End	Downstream End
12:00		
1:00		
2:00		
3:00		
4:00		
5:00		
6:00		
7:00		
8:00		
9:00		
10:00		
11:00		

SECTION 3 – Chemical Analysis Worksheet

Test Locations: (e.g.; specific segment of pipe; location; comments)	

Table 1 Chemical Analysis			
Element	**Weight Percent**	**Element**	**Weight Percent**
Carbon (C)		Molybdenum (Mo)	
Manganese (Mn)		Columbium (Cb)	
Phosphorus (P)		Vanadium (V)	
Sulfur (S)		Titanium (Ti)	
Silicon (Si)		Cobalt (Co)	
Aluminum (Al)		Tin (Sn)	
Copper (Cu)		Boron (B)	
Nickel (Ni)		Calcium (Ca)	
Chromium (Cr)			

Table 2 Chemical Analysis of Corrosion Products present at Failure Site		
Location	Significant Constituents	Comments and Findings

Table 3 Chemical Analysis of Liquids or other Materials of interest present at Failure Site		
Location	Significant Constituents	Comments and Findings

Remarks:

_____

_____

_____

SECTION 4 – Metallographic Specimens and Photograph Worksheet

Metallographic Specimen worksheet		
Sample #	**Location**	**Description**

Metallographic Sections and Photograph worksheet				
Photo#	**Sample #**	**Mag**	**Etchant**	**Description**

APPENDIX B – PRESSURE CYCLE AGGRESSIVENESS DETERMINATION EXAMPLE

Pressure Cycle Aggressiveness Determination Example

Consider a pipeline that operates annually with pressure cycles represented by Figure B-1 below.

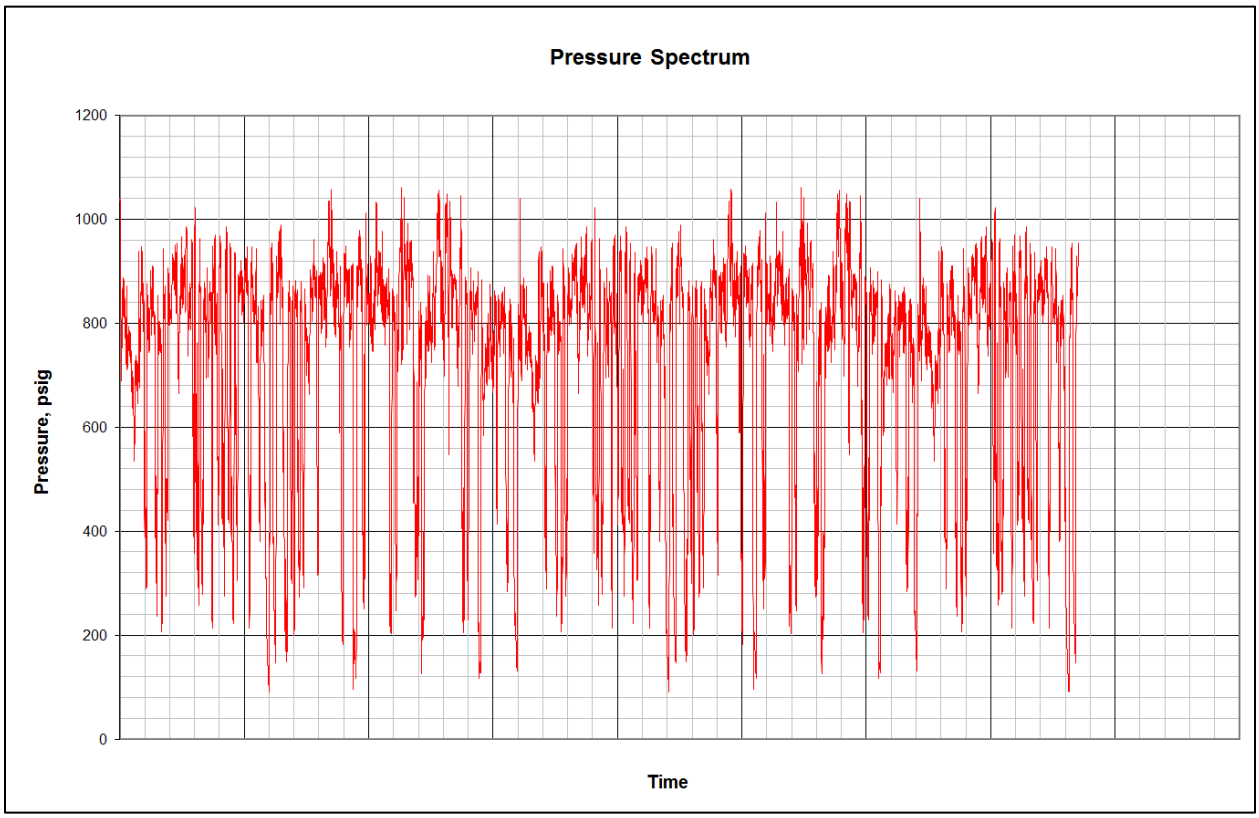


Figure B-1. 365 Days of Operating Pressure

The 100% SMYS value for this example pipe segment is 1,480 psi. The MOP is 72% SMYS, or 1,065 psig. The number of cycles in a given pressure range (or bin) are converted to an equivalent 72% SMYS cycle count using Equation B-1.

$$\sum n_i \left(\frac{P_i}{P_{eq}} \right)^3$$

Equation B-1

where

n_i	is the number of cycles occurring within the stress range
P_i	is the highest level of pressure within the stress range (psi)
P_{eq}	is the pressure value equal to 72% SMYS (psi)

The pressure cycle counted data in bins of 5% SMYS are provided in Table B-1 below. The sum total equivalent 72% SMYS cycle count for the data set is 35. When comparing 35 equivalent 72% SMYS cycles to those listed for each benchmark categories given in Table B-2, the aggressiveness result is Moderate. This is because the mid-point between Light and Moderate is 28 and 35 is less than 40 but greater than 28.

Table B-1. Annual Cycle Count for Example Pipeline Operation

Pressure Cycle Size (bin)		Count	Equivalent 72% SMYS Cycle Count
70 - 72% SMYS	1,065 psig	0	0
65 - 70% SMYS	1,036 psig	4	4
60 - 65% SMYS	962 psig	5	3
55 - 60% SMYS	888 psig	8	4
50 - 55% SMYS	814 psig	10	4
45 - 50% SMYS	740 psig	21	7
40 - 45% SMYS	666 psig	23	6
35 - 40% SMYS	592 psig	14	2
30 - 35% SMYS	518 psig	7	1
25 - 30% SMYS	444 psig	10	1
20 - 25% SMYS	370 psig	11	0
15 - 20% SMYS	296 psig	21	0
10 - 15% SMYS	222 psig	69	1
5 - 10% SMYS	148 psig	238	1
25 psi - 5% SMYS	74 psig	674	0
0 - 25 psig	25 psig	1,866	0
Total Equivalent 72% Cycles			35

Table B-2. Annual Benchmark Cycle Counts

Pressure Cycle Size	Very Aggressive	Aggressive	Moderate	Light
66 - 72% SMYS	20	4	1	0
56 - 65% SMYS	40	8	2	0
46 - 55% SMYS	100	25	10	0
36 - 45% SMYS	500	125	50	25
26 - 35% SMYS	1000	250	100	50
25 psi - 25% SMYS	2000	500	200	100
0 - 25 psi	0	0	0	0
Total Equivalent 72% Cycles	415	101	40	16