GL Noble Denton

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# Project #153M
# Guidance for Assessing the Remaining Strength of Corroded Pipelines

*Not Restricted*


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# Executive Summary

Incident statistics have consistently shown that corrosion is the primary cause of pipeline failures in liquid pipelines, and is the second largest cause of failures in natural gas transmission pipelines and distribution piping. Corrosion can cause metal loss defects, which can have a smooth or an irregular profile and can occur either on the internal or external surface of the pipeline, or defects may occur on both surfaces, depending on the local environment and the product transported in the pipeline. Corrosion can occur in the parent wall of the pipeline, in the heat affected zones, or at the girth or seam welds. The damage may be in the form of a single defect or as a colony of defects.

External corrosion occurs due to environmental conditions on the exterior surface of the pipeline, e.g. from the natural chemical interaction between the exterior of the pipeline and the soil, air, or water surrounding it. Internal corrosion occurs due to chemical attack on the interior surface of the steel pipe from either the product being transported or other materials which are transported within the pipeline. Other, more specialized types of corrosion such as stress corrosion cracking (SCC), microbial corrosion, and selective seam corrosion can also occur. These types of corrosion can be exacerbated by environmental conditions, manufacturing processes and applied stresses resulting from normal pipeline operations.

Corrosion is a time dependent threat to a pipeline. If left untreated, corrosion can result in the gradual reduction of the wall thickness of the pipe and a resulting loss of pipe strength. This loss of pipe strength could eventually result in a leak or rupture of the pipeline due to internal pressure or external loading unless the corrosion damage is repaired, the affected pipeline section is replaced, or the operating pressure of the pipeline is reduced. Pipeline corrosion creates weaknesses at points in the pipe, which in turn make the pipe more susceptible to third party damage, overpressure events, etc. Therefore, the risks associated with corrosion damage need to be considered in conjunction with other forms of damage in pipelines.

An assessment of the remaining strength of corroded pipelines is generally undertaken using the ASME B31G, Modified ASME B31G and RSTRENG methods. These methods were developed using a modified version of the toughness independent ductile failure criterion for assessing pressurized pipes containing axially orientated surface-breaking defects. This criterion was originally developed by Battelle Columbus Laboratories under the sponsorship of the Pipeline Research Committee of the American Gas Association, Project NG-18. A new manual, ASME B31G-2009, which describes methods for determining the remaining strength of corroded pipelines, was approved by the American National Standards Institution (ANSI) on July 10, 2009. For ease of use and consistency, this Guidance Document uses the same format and nomenclature, in general, as that given in ASME B31G-2009.

Since the original development of the ASME B31G, Modified ASME B31G and RSTRENG methods, considerable effort has been funded by Pipeline Research Council International, Inc (PRCI) and by various industry groups, particularly in Europe, in the development of improved assessment methods. The new methods developed include the LPC, DNV RP-F101, SHELL92 and PCORRC methods.

In the late 1990's and early 2000's, PRCI funded the research projects PR-273-9803 and PR-273-0323 with Germanischer Lloyd Industrial Services USA, Inc. (hereafter referred to as GL; formerly Advantica) which were aimed at improving existing guidance for assessing the remaining strength of corroded pipelines. On completion of these projects, guidance for assessing the remaining strength of corroded pipelines was developed by GL in 2002 for PRCI (PRCI Report Catalog No. L51958). Following on from this, PRCI and the Pipeline and Hazardous Materials Safety Administration (PHMSA) jointly co-funded Project #153 (PHMSA R&D Reference DTPH56-05-T-0003) with Electricore, Inc. and GL.

These research projects have resulted in the development of improved guidance for assessing the remaining strength of corroded pipelines. New guidance has been developed for assessing:

- Closely spaced corrosion defects

- Corrosion defects in high strength pipelines
- Corrosion defects in pipelines subject to combined internal pressure and external loading
- Corrosion defects in pipelines subject to cyclic pressure loading
- Corrosion defects in vintage, low toughness pipelines

Separately to this project, the Gas Technology Institute (GTI) commissioned work with Battelle to develop guidelines for assessing corrosion associated with pipeline girth and long seam welds.

This Guidance Document is a revision to the version issued in 2002 (PRCI Report Catalog No. L51958). It provides recommended practice for assessing the remaining strength of pipelines containing metal loss defects. The methods provided in this document are intended to be used to assess corrosion defects in carbon steel pipelines that have been designed to recognized pipeline codes. These codes include but are not limited to: ASME B31.4, ASME B31.8, ASME B31.11, PD 8010, DNV OS-F101, IGEM/TD/1, ISO 13623 and CSA Z662.

This Guidance Document shall only be used by engineers who are competent in conducting fitness for purpose assessments of pipelines. It is the sole responsibility of the user to exercise professional judgment in using this Guidance Document. If there is any doubt, or confusion, at any stage of the assessment, then advice shall be sought from an organization or a competent engineer who has access to the full range of relevant specialist services in the field of materials engineering, in-line inspection (ILI), non-destructive testing (NDT), design, operation, fitness for service assessment, finite element analysis and repair.

This Guidance Document will be updated as assessment methods evolve.

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# 1 Introduction

## 1.1 Background

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## 1.2 Development of Industry Assessment Guidance

An assessment of the remaining strength of corroded pipelines is generally undertaken using the ASME B31G, Modified ASME B31G and RSTRENG methods. These methods were developed using a modified version of the toughness independent ductile failure criterion for assessing pressurized pipes containing axially orientated surface-breaking defects. This criterion was originally developed by Battelle Columbus Laboratories under the sponsorship of the Pipeline Research Committee of the American Gas Association, Project NG-18.

Since the original development of the ASME B31G, Modified ASME B31G and RSTRENG methods, considerable effort has been funded by Pipeline Research Council International, Inc (PRCI) and by various industry groups, particularly in Europe, in the development of improved assessment methods. The new methods developed include the LPC, DNV RP-F101, SHELL92 and PCORRC methods.

In the late 1990's and early 2000's, PRCI funded the research projects, PR-273-9803 and PR-273-0323 with Germanischer Lloyd Industrial Services USA, Inc. (hereafter GL, formerly Advantica[1]), which were

[1] Advantica was acquired by Germanischer Lloyd in 2007

aimed at improving existing guidance for assessing the remaining strength of corroded pipelines. On completion of these projects, guidance for assessing the remaining strength of corroded pipelines was developed by GL in 2002 for PRCI (PRCI Report Catalog No. L51958). Following on from this, PRCI and the Pipeline and Hazardous Materials Safety Administration (PHMSA) jointly co-funded Project #153 (PHMSA R&D Reference DTPH56-05-T-0003) with Electricore, Inc. and GL.

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Separately to this project, the Gas Technology Institute (GTI) commissioned work with Battelle to develop guidelines for assessing corrosion associated with pipeline girth and long seam welds.

A new manual, ASME B31G-2009, which describes methods for determining the remaining strength of corroded pipelines, was approved by the American National Standards Institution (ANSI) on July 10, 2009. The new guidance given in this document should be read in conjunction with that given in ASME B31G-2009. For ease of use and consistency, this Guidance Document uses the same format and nomenclature, in general, as that given in ASME B31G-2009.

## 1.3 Scope

This Guidance Document is a revision to the version issued in 2002 (PRCI Report Catalog No. L51958). It provides recommended practice for assessing the remaining strength of pipelines containing corrosion defects. The methods provided in this document are intended to be used to assess corrosion defects in carbon steel pipelines that have been designed to recognized pipeline codes, such as, but not limited to: ASME B31.4, ASME B31.8, ASME B31.11, PD 8010, DNV OS-F101, IGEM/TD/1, ISO 13623 and CSA Z662.

This Guidance Document will be updated as assessment methods evolve.

## 1.4 Acceptable Applications

This Guidance Document is limited to the assessment of metal loss in pipelines within the following limitations:

a) Metal loss in pipelines located below ground, above ground or offshore.

b) Metal loss due to external or internal corrosion.

c) Metal loss of a depth not exceeding 80% of the actual pipe wall dimension when using the ASME B31G, Modified ASME B31G and RSTRENG methods. When using the LPC method, metal loss of a depth up to 85% of the actual pipe wall dimension may be assessed.

d) Metal loss produced by grinding when used to completely remove mechanical damage, cracks, arc burns, manufacturing or other defects from the pipe surface.

e) Metal loss in pipelines operating at temperatures above ambient and within the range of operating temperatures of the governing design standard, provided that material properties at the elevated temperature are used in the assessment.

## 1.5 Limitations

This Guidance Document is limited to the assessment of metal loss in carbon steels used to construct pipelines. Typical of these materials are those described in ASTM A 53, A 106, A 381 and API 5L/OSO 3183 or equivalent.

The Guidance Document shall only be used to assess defects in straight sections of pipeline. Corrosion defects have relatively smooth contours of metal loss that have been introduced gradually over the service life of the pipeline. The assessment methods detailed are only applicable to linepipe steels that are expected to fail by plastic collapse.

This Guidance Document does not apply to the following:

a) crack-like defects.

b) combined corrosion and crack-like defects.

c) combined corrosion and mechanical damage.

d) metal loss defects due to mechanical damage (e.g. gouges).

e) metal loss in indentations and buckles, or metal loss that is coincident with other damage.

f) metal loss in fittings.

g) pipelines that operate at temperatures outside their original design envelope or operating at temperatures in the creep range.

## 1.6 Nomenclature, Terms and Definitions

| | | |
|---|---|---|
| A | = | Local area of metal loss in the longitudinal plane |
| $A_o$ | = | Local original metal area = *Lt* |
| ACL | = | 'Half' axial corrosion length (pipe surface dimension) |
| anomaly | = | An unexamined deviation from the norm in the pipe, coatings or welds |
| CCL | = | 'Half' circumferential corrosion length (pipe surface dimension) |
| CD | = | Corrosion depth: ratio of *d/t* |
| clustering | = | Grouping of anomalies according to an interaction criterion |
| $C_o$ | = | A constant relating to the mean $S_r$-*N* curve |
| D | = | Specified outside diameter of the pipe |
| d | = | Depth of metal loss |
| $\delta$ | = | Number of standard deviations below the mean |
| defect | = | A physically examined anomaly with dimensions or characteristics that exceed acceptable limits |
| ECA | = | Engineering Critical Assessment |
| $F_A$ | = | Axial compressive force on pipeline |
| feature | = | Any physical object detected by an in-line inspection system. Features may be anomalies, components, nearby metallic objects, welds or some other item |
| girth weld | = | A complete circumferential butt weld joining pipe or components |
| imperfection | = | An anomaly with characteristics that do not exceed acceptable limits |
| indication | = | A signal from an in-line inspection system. After investigation, an indication may be further classified as an anomaly, imperfection or component |
| ILI | = | In-Line Inspection |
| L | = | Length of metal loss |
| lamination | = | An internal metal separation creating layers generally orientated parallel to the pipe wall |
| M | = | Bulging (Folias) stress magnification factor |
| MAOP | = | Maximum allowable operating pressure |
| MOP | = | Maximum operating pressure, i.e. the highest pressure the pipeline operates at during a normal operating cycle |
| $M_A$ | = | Bending moment on pipeline |
| m | = | The inverse slope of the *Log* $S_r$ versus *Log N* curve |
| N | = | Number of cycles to failure |
| $P_A$ | = | Pipeline internal pressure |

| | | |
|---|---|---|
| $P_f$ | = | Estimated failure pressure for pipeline subject only to internal pressure loading |
| $P_f^{comb}$ | = | Estimated failure pressure for pipeline subject to combined loading |
| $P_s$ | = | Safe operating pressure |
| (P2/P1) | = | Ratio of failure pressures of two interacting defects. P2 is the failure pressure of a pair of defects that interact and P1 is the failure pressure of the single defect from the pair that gives the lower failure pressure |
| SCF | = | Stress concentration factor |
| seam weld | = | The longitudinal or spiral weld in linepipe, which is made in the pipe mill |
| shall | = | Used in this Guidance Document to indicate a mandatory requirement |
| should | = | Used in this Guidance Document to indicate a non mandatory requirement but recommended as good practice |
| SF | = | Safety factor |
| $S_F$ | = | Estimated failure stress level |
| $S_{flow}$ | = | Flow stress |
| $S_r$ | = | Maximum local hoop stress range |
| SMTS | = | Specified minimum tensile strength at ambient conditions |
| SMYS | = | Specified minimum yield strength at ambient conditions |
| $S_{UT}$ | = | Specified ultimate tensile strength at temperature, may equal SMTS |
| $S_{YT}$ | = | Specified yield strength at temperature, may equal SMYS |
| $\sigma$ | = | Standard deviation of *Log N* about the mean line |
| t | = | Nominal pipe wall thickness |
| z | = | $L^2/Dt$ |

## 1.7 Responsibility

This Guidance Document shall only be used by engineers who are competent in conducting fitness for service assessments of pipelines. It is the sole responsibility of the user to exercise professional judgment in using this Guidance Document. If there is any doubt, or confusion, at any stage of the assessment, then advice shall be sought from an organization or a competent engineer who has access to the full range of relevant specialist services in the field of materials engineering, in-line inspection (ILI), non-destructive testing (NDT), design, operation, fitness for service assessment, finite element analysis and repair and operation.

## 1.8 Assessment Procedure

Three levels of assessment are provided in this Guidance Document. Each assessment level provides a balance between: conservatism, the information available to conduct the assessment, the knowledge and experience of the engineer and the overall complexity.

The decision on which level to use depends on the information available. It is the responsibility of the pipeline operator/engineer to select the assessment level based on the information available regarding the pipeline, loading conditions and defect geometry, together with the degree of conservatism required.

On completion of the in-line inspection (ILI), a report by the ILI tool vendor will be available to the operator. The ILI performance specification will have clearly stated the type of anomalies that are to be detected, identified and sized. The types of anomalies that may be detected include:

- Internal or external corrosion damage
- Gouges
- Grooves
- Cracks in the pipe body, stress corrosion cracking (SCC) and cracks in the seam/girth weld
- Dents
- Pipe Ovality
- Wrinkles or ripples
- Buckles
- Manufacturing anomalies, such as laminations, slivers, arc strikes, missing weld caps, etc.

This Guidance Document shall only be used to assess metal loss defects. Specialist advice shall be sought in the following cases:

- Crack-like defects or mechanical damage
- Grooving corrosion, selective corrosion, or preferential corrosion affecting pipe seam or girth welds
- Corrosion in fittings
- The pipeline operates at temperatures outside its original design envelope

An algorithm that summarizes the assessment procedures described in this Guidance Document is shown in Figure 1.8-1.

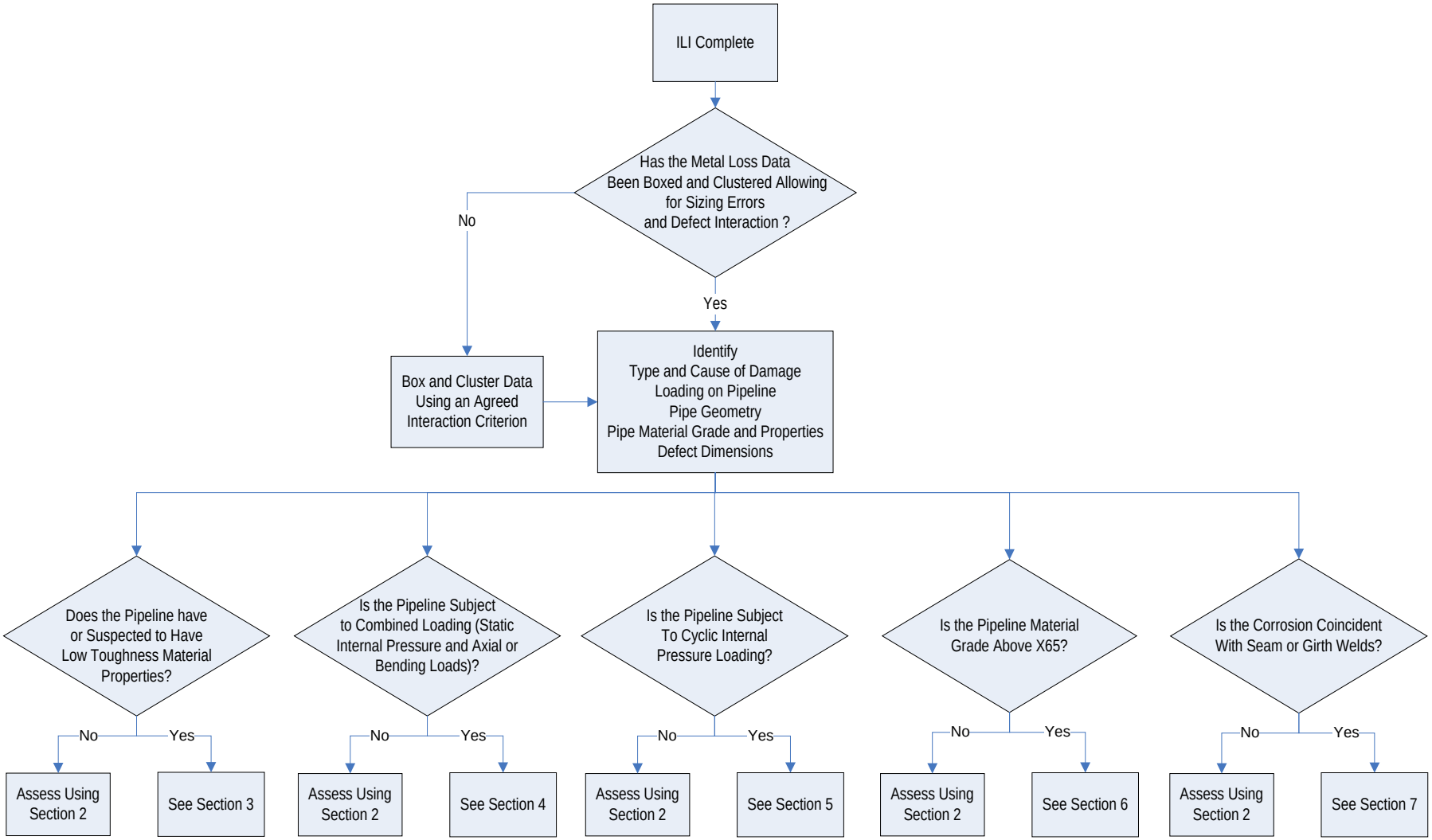


Figure 1.8-1 Assessment Algorithm

## 1.9 Validation

The methods described in this Guidance Document have been validated using the results of burst tests and service failures of linepipe affected by corrosion or simulated (machined) metal loss. Sources of burst test data on linepipe of strength grade up to X100 are given in the references cited below.

[References: (1) Kiefner, J.F., Vieth, P.H., and Roytman, I., 'Continued Validation of RSTRENG', PRCI Catalog No. L51749, Contract PR 218-9304, December 20, 1996; (2) Chauhan, V., and Brister, J., 'A Review of Methods for Assessing the Remaining Strength of Corroded Pipelines', Germanischer Lloyd Report 6781, Issue 6.1, November 2009; (3) Chauhan, V., and Wood, A., 'Experimental Validation of Methods for Assessing Closely Spaced Corrosion Metal Loss Defects in Pipelines', GRI 8549, Advantica, Inc. Report for PRCI/GRI, September 2004; (4) Chauhan, V., and Grant, R., 'Improved Methods for the Assessment of the Remaining Strength of Corroded Pipelines (Phase 4)', Advantica, Inc. Report for PRCI, Contract PR-273-9803; (5) Martin, M., and Andrews, R.M., 'Project #153L - The Remaining Strength of Corroded Low Toughness Pipe', Germanischer Lloyd Report R9247 Issue 2.0, June 2008; (6) Swankie, T., Robinson, M., Liu, J., Crossley, J., and Morgan, G., 'Project #153K - The Assessment of Corrosion Damage in Pipelines Subjected to Cyclic Pressure Loading', Germanischer Lloyd Report R8928 Issue 1.0, January 2009; (7) Swankie, T., 'Project #153K - The Assessment of Corrosion Damage in Pipelines Subjected to Cyclic Pressure Loading. Addendum to GL Report R8928, Issue 1.0', Germanischer Lloyd Report 9474, Issue 1.0, December 2009; Leis, B.N., Clark, E.B., Zhu, X.K., Galliher, R.D., 'Guidelines for Assessing Corrosion Associated with Girth and Long Seam Welds', Battelle Final Report Number GRI-04/0119 prepared for Gas Technology institute (Contract Number 8521), October 2004].

## 1.10 Software

It is recommended that the methods described in this Guidance Document are conducted using a software program. This will help to facilitate Level 1 assessments and is essential for conducting Level 2 assessments. Level 3 assessments will require the use of verified finite element pre- and post- processing software.

## 1.11 Accuracy

The accuracy of recorded defect size(s) and position(s) shall be considered when conducting assessments according to the methods described in this Guidance Document. Consideration shall be given to the proximity of defects to welds, fittings and other forms of damage. In the case of recorded defect sizes from an ILI, the vendor should provide inspection tolerances of the tool used. Methods of accounting for the uncertainty in indirectly sized defects include increasing the defect size to account for sizing errors of the ILI tool.

## 1.12 Defect Interaction

Corrosion in pipelines can occur such that areas of metal loss are closely spaced in the longitudinal, circumferential (transverse) or helical directions. If the areas of metal loss are closely spaced then it is possible that they can interact and fail at a pressure lower than that predicted based on an analysis of single, isolated defects. It is a common practice for the criterion used to box and cluster anomalies detected from an ILI to be agreed between the pipeline operator and the tool vendor. Clustering according to an agreed interaction criterion should, therefore, have already been conducted when the ILI vendor supplies the inspection results to the operator. The interaction criterion used by the ILI tool vendor shall be confirmed prior to conducting defect assessments described in this Guidance Document. If the ILI data has not been

clustered, then a defect interaction criterion shall be used before conducting the assessments described in this Guidance Document.

Extensive numerical analysis and burst testing have been conducted to develop criteria for assessing the interaction of closely spaced corrosion defects in pipelines. Interaction between two defects can be assessed depending on the defect type and orientation, either in the axial or circumferential direction as shown in Figure 1.12-1. Defect types that can be assessed are pits, grooves and patches[2].

Figures 1.12-2 to 1.12-4 show how interaction between two defects can be assessed. In these figures (P2/P1) is the ratio of failure pressures of two interacting defects. P2 is the failure pressure of a pair of defects that interact; P1 is the failure pressure of the single, isolated defect from the pair that gives the lower failure pressure and the separation distance between the two defects is normalized to the nominal pipe wall thickness, t.

Interaction can be assessed for defects that are either on the external or internal surface of pipeline. Where an internal and external defect pair overlap as shown in Figure 1.12-5, then they should be combined to form a composite defect. This composite defect shall be formed by taking the combined defect length. The depth of the composite defect is the sum of the maximum depths of the internal and external defects.

[References: (1) Chauhan, V., and Wood, A., 'Experimental Validation of Methods for Assessing Closely Spaced Corrosion Metal Loss Defects in Pipelines', GRI 8549, Advantica, Inc. Report for PRCI/GRI, September 2004; (2) Chauhan, V., and Grant, R., 'Improved Methods for the Assessment of the Remaining Strength of Corroded Pipelines (Phase 4)', Advantica, Inc. Report for PRCI, Contract PR-273-9803; Anon., 'Corroded Pipelines', Recommended Practice DNV-RP-F101, Det Norske Veritas, October 2006].

[2] Pits are defined as localized regions of metal loss, confined to small areas. They are often referred to as circular patches which are characterized by a pit diameter that is of the same order as the plate thickness or less. In this Guidance Document larger diameter (8t) patches are also referred to as pits.

Grooves are defined as long elongated thinned areas caused by directional corrosion or erosion. The length of the groove is much greater than the width. The interaction criteria given in this Guidance Document have been validated for grooves of length 8t and width 2t and a (d/t) ratio of 0.8.

Patches are defined as general areas of metal loss in both the axial and circumferential directions. The interaction criteria given in this Guidance Document have been validated for square patches of axial/circumferential extent up to 8t and a (d/t) ratio of 0.8.

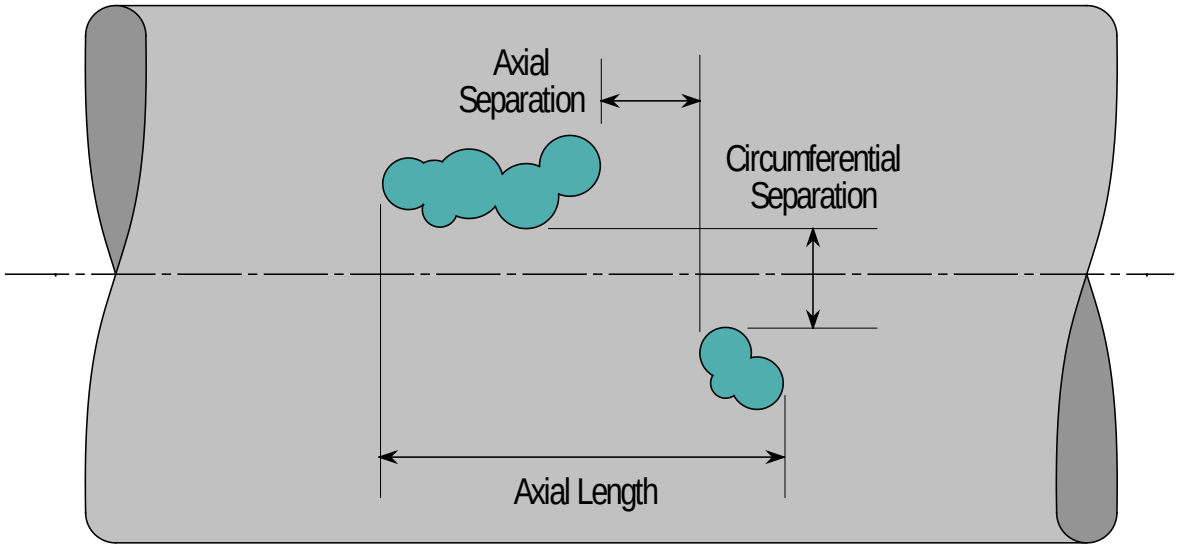


Figure 1.12-1 Corrosion Defect Interaction Distances

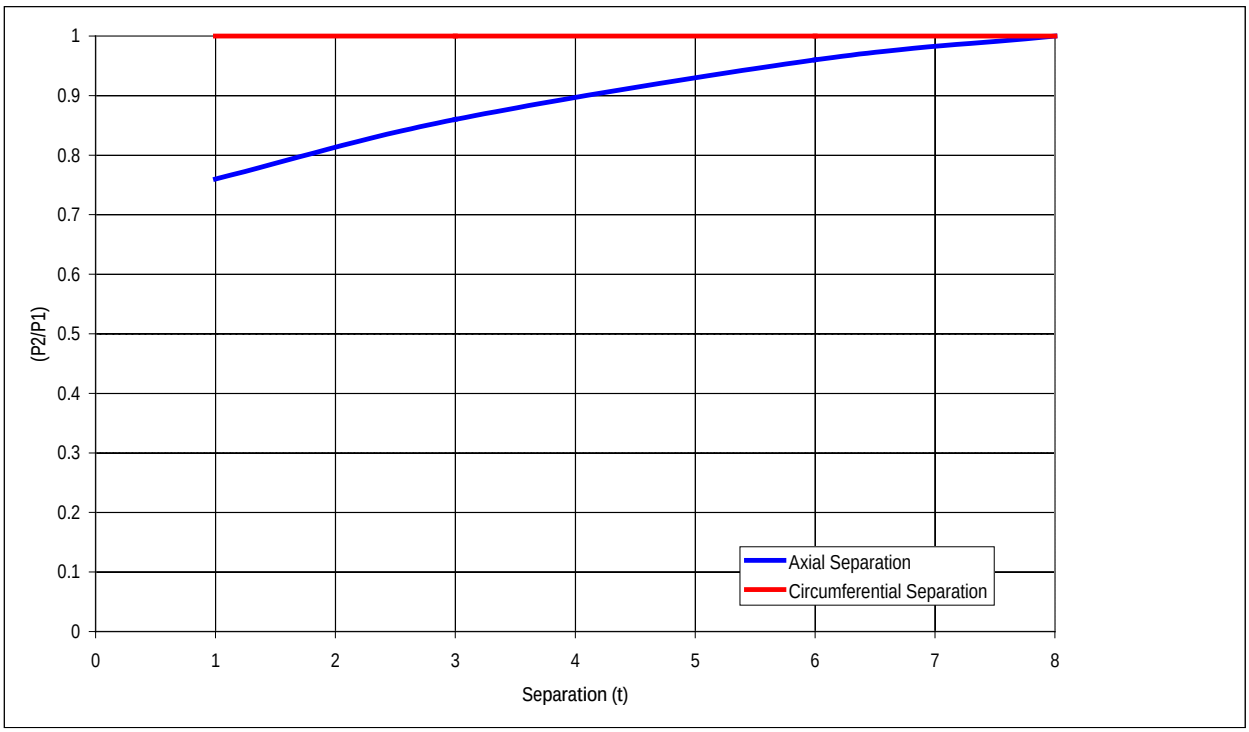


Figure 1.12-2 Interaction of Axial and Circumferential Groove and Patch Defects

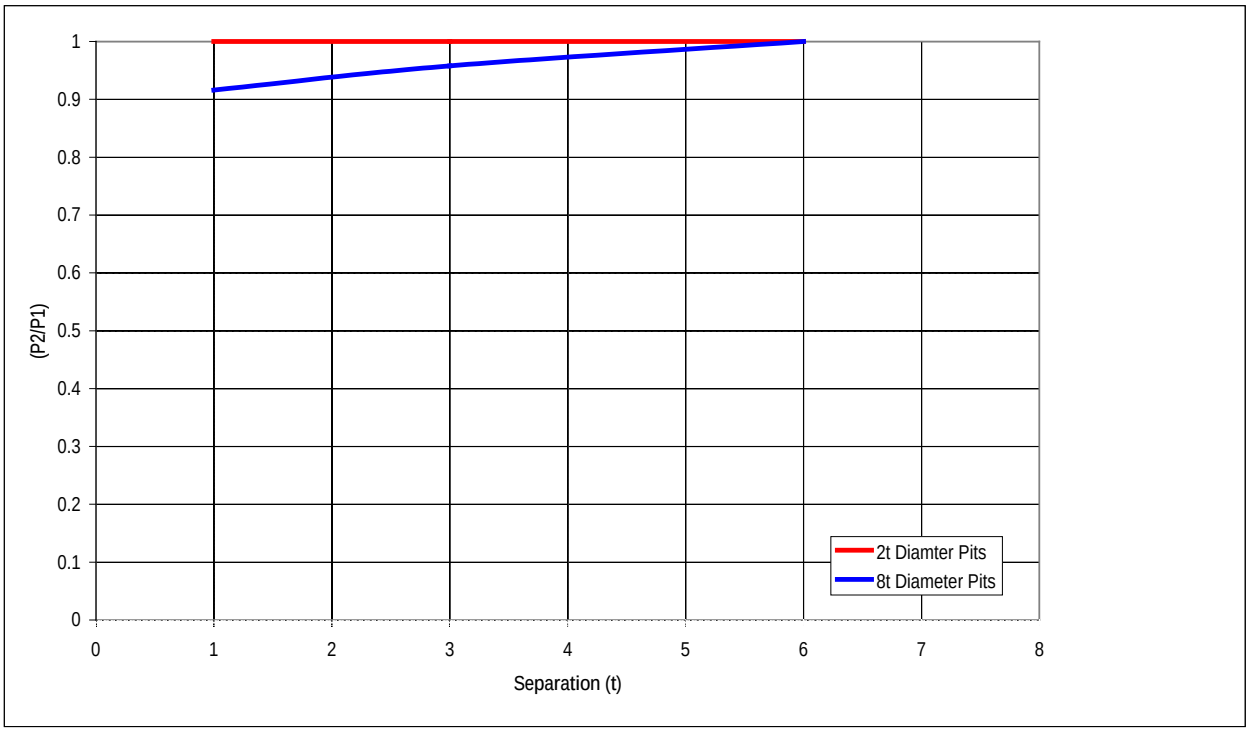


Figure 1.12-3 Interaction of Axially Separated Pit Defects

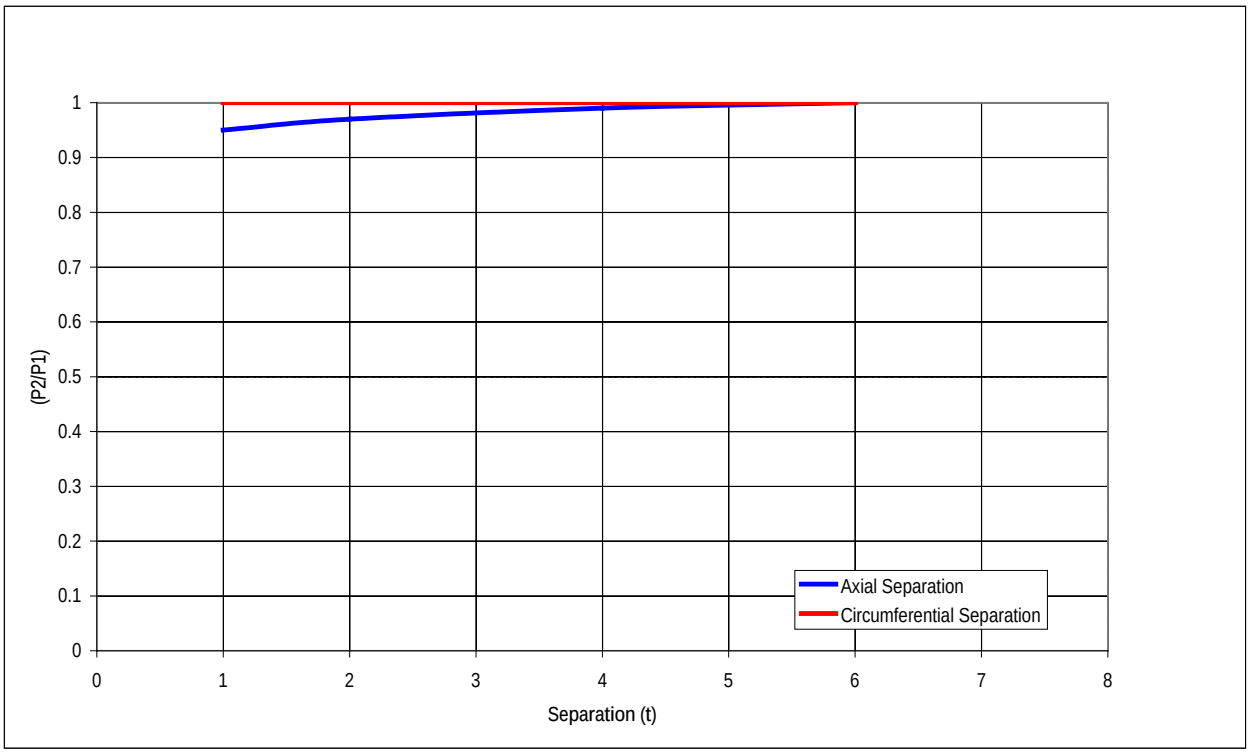


Figure 1.12-4 Interaction of Pit and Groove or Patch Defects

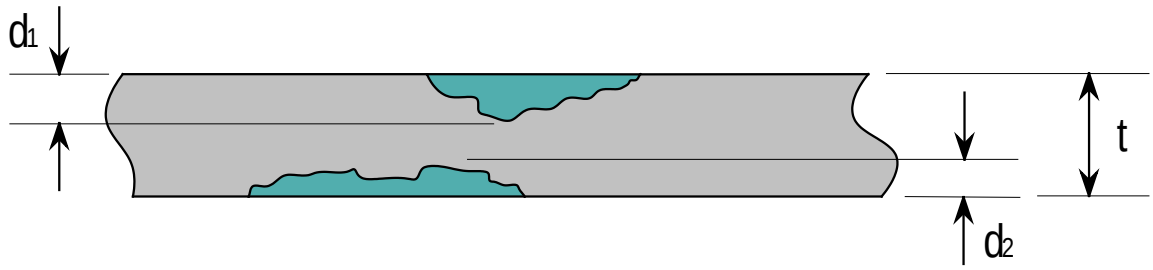


Figure 1.12-5 Overlapping External and Internal Defects

## 1.13 Defect Orientation

Corrosion defects can occur over a relatively wide area of the pipe surface and may be orientated longitudinally, circumferentially or in a helical direction. The orientation of the defect will be influenced by the cause of the corrosion. For example, disbondment of continuous wrapped coatings may lead to corrosion in a helical direction. ASME B31G, RSTRENG and LPC-1 have been validated using burst tests conducted on linepipe with longitudinally orientated defects subjected to internal pressure loading. Guidance given in ASME B31G-2009 shall be used for assessing corroded areas that are orientated at an angle to the pipe axis.

[References: (1) Anon., 'Manual for Determining the Remaining Strength of Corroded Pipelines, Supplement to ASME B31 Code for Pressure Piping', ASME B31G-2009 (Revision of ASME B31G-1991), The American Society of Mechanical Engineers, 2009]

## 1.14 Material Properties and Other Data

Specified minimum material properties shall be used when conducting Level 1 and 2 assessments. Actual material properties from mill test reports or from tensile testing may be used for Level 3 assessments.

An explanation of the concept of flow stress is given in ASME B31G-2009.

## 1.15 Safety Factors and the Meaning of Acceptance

A pipeline with a metal loss defect is considered acceptable when the estimated failure stress multiplied by a suitable safety factor is equal to or greater than the hoop stress at the operating pressure. There is no single safety factor that is suitable for all types of pipeline construction, for all modes of pipeline operation, loading conditions, or for all types of defects. This Guidance Document recommends use of a minimum safety factor given in ASME B31G-2009, i.e. equal to the ratio of the minimum hydrostatic test pressure required for the given type of pipeline construction to the MAOP or MOP.

[References: (1) Anon., 'Manual for Determining the Remaining Strength of Corroded Pipelines, Supplement to ASME B31 Code for Pressure Piping', ASME B31G-2009 (Revision of ASME B31G-1991), The American Society of Mechanical Engineers, 2009].

# 2 Assessment Methods

Figure 2-1 shows idealized defect shapes for the assessment methods described in this Guidance Document. These assessment methods are described in sections 2.1 and 2.2.

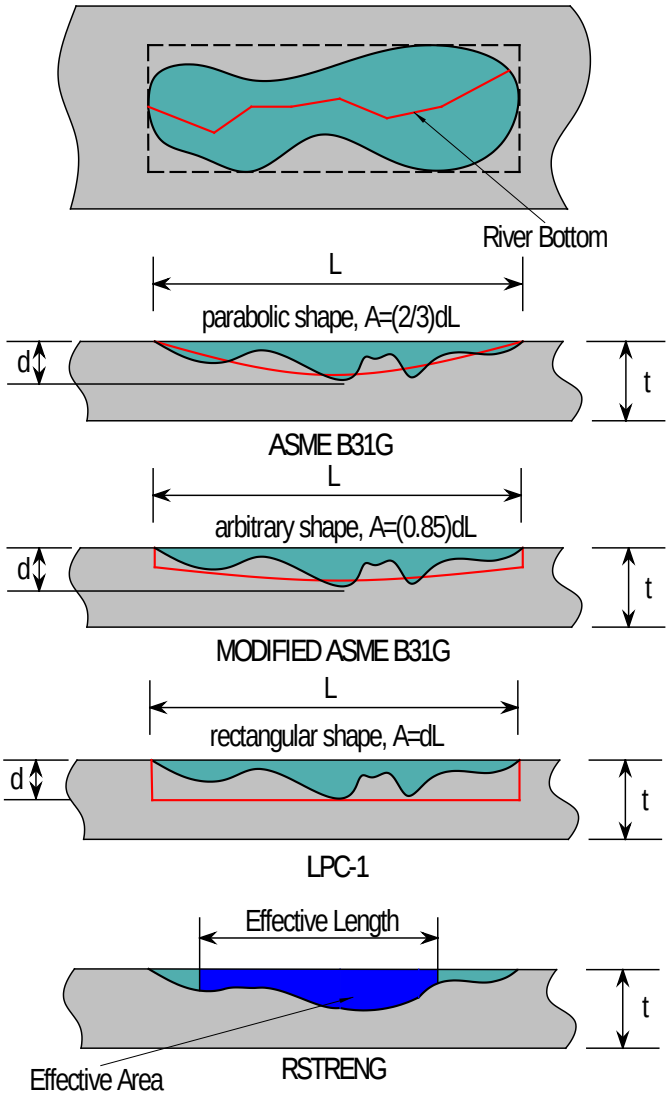


Figure 2-1 Defect Shapes Used in this Guidance Document

## 2.1 Level 1 Assessment

A Level 1 assessment provides a simple means to assess the remaining strength of a corroded pipeline. It uses a single measurement of the maximum depth and axial length of a metal loss area. A Level 1 Assessment shall be conducted using the ASME B31G, Modified ASME B31G or LPC-1 methods. It is also possible to conduct Level 1 assessments using the SHELL92 and PCORRC methods. These methods are not described in this Guidance Document. Details of these methods are described in GL Report 6781 Issue 6.1; see Section 1.9 for the full reference.

### 2.1.1 Original ASME B31G Method

For $z \leq 20$ and $d/t \leq 0.8$

$$S_F = S_{flow}\left[\frac{1-\frac{2}{3}(d/t)}{1-\frac{2}{3}(d/t)/M}\right] \quad [1]$$

For $z >$ 20 and $d/t \leq 0.8$

$$S_F = S_{flow}(1-d/t) \quad [2]$$

Where,

$$M = (1+0.8z)^{1/2} \quad [3]$$

$$S_{flow} = 1.1(SMYS) \quad [4]$$

### 2.1.2 Modified ASME B31G Method

For $z \leq 50$ and $d/t \leq 0.8$

$$S_F = S_{flow}\left[\frac{1-0.85(d/t)}{1-0.85(d/t)/M}\right] \quad [5]$$

Where

$$M = (1+0.6275z-0.003375z^2)^{1/2} \quad [6]$$

$$S_{flow} = SMYS + 10ksi \quad [7]$$

For $z > 50$ and $d/t \leq 0.8$

$$S_F = S_{flow}\left[\frac{1-0.85(d/t)}{1-0.85(d/t)/M}\right] \quad [8]$$

Where

$$M = 3.3 + 0.032z \quad [9]$$

$$S_{flow} = SMYS + 10ksi \quad [10]$$

### 2.1.3 LPC-1 Method

For $d/t \leq 0.85$ and all defect lengths

$$S_F = S_{flow}\left[\frac{1-(d/t)}{1-(d/t)/M}\right] \quad [11]$$

Where

$$M = (1 + 0.31z)^{1/2} \quad [12]$$

$$S_{flow} = SMTS \quad [13]$$

## 2.2 Level 2 Assessment

A Level 2 assessment shall be undertaken using the RSTRENG, Effective Area Method. This method requires measurements of the depth of corrosion in the damaged area of the pipeline. The RSTRENG method uses a river-bottom profile of the corroded area to predict the failure pressure more accurately than from a Level 1 assessment. The method evaluates all possible combinations of the local area of metal loss, $A$, in the longitudinal plane, with respect to the local, uncorroded area, $A_0$. A detailed profile is determined by obtaining several measurements of metal loss or remaining wall thickness throughout the damaged area. Measurements can be arranged either in a grid pattern as described in API 579-1/ASME FFS-1 or follow a river bottom along a path through the deepest areas of metal loss (see Figure 2-1). The failure pressure is calculated for all possible combinations of metal loss with respect to the surrounding material using the Equation:

$$S_F = S_{flow}\left[\frac{1-(A/A_0)}{1-(A/A_0)/M}\right] \quad [14]$$

The lowest predicted failure pressure shall govern. As the assessment procedure is iterative, the use of a verified computer program or spreadsheet is recommended.

## 2.3 Level 3 Assessment

### 2.3.1 Method

A Level 3 assessment is conducted using numerical analysis, typically by constructing a finite element (FE) model of the corroded pipeline and then predicting the failure pressure using a validated failure criterion. The FE method is versatile and can be used to predict the failure pressure of a corroded pipeline under internal pressure and external loading, and with pipe ovality, deformations, misalignments, discontinuities, material properties, etc. A Level 3 assessment shall only be conducted by an engineer/analyst who is experienced in FE analysis and who has knowledge of the limitations of the software. Accuracy of the failure prediction depends on a number of factors. At every step of the analysis, judgment is required. Knowledge of structural analysis and materials behavior, and experience in non-linear finite element analysis, are essential.

Briefly, the analysis consists of the following four steps:

1. Create a finite element model of the corroded pipeline, using the measured defect size, pipe geometry, pipe material properties, loading and boundary conditions
2. Perform a non-linear, large-deformation stress analysis using a verified finite element analysis software program
3. Examine the results obtained from the stress analysis
4. Determine the failure or critical pressure value based on the variation of local stress or strain states

### 2.3.2 Construction of the Finite Element Model

A pipeline containing either a single corrosion defect or a colony of defects can be modeled using a three dimensional finite element model.

The use of actual defect sizes is preferable but it is not always necessary. A defect shape can be simplified, but its maximum dimensions (length, width and depth) shall be used. Account should also be taken of possible uncertainty in the measurement of the defect shape and dimensions. The minimum value of the wall thickness measured in a local region around the defect shall be used.

The analyst should use experience and judgment on the defect shape simplification, the mesh density through the defect ligament and the extent of the mesh refinement area. In general, the use of a fine mesh in the area of the defect will give the most accurate failure predictions.

Sensitivity and convergence studies shall be conducted to demonstrate that adequate mesh design and analysis procedures have been used. A coarse finite element mesh can be used for the pipe or vessel wall away from the defect. The mesh density should be gradually increased towards the local area containing the defect. It is recommended that four layers of elements are provided through the minimum ligament of the defect. The longer the circumferential length of the defect, the fewer the element layers required. Solid, second-order elements, such as 20-noded hexahedral elements, should be used. Severe element distortions, especially at the minimum ligament of the defect, should be avoided. The length of pipe section simulated should be at least five times the pipe diameter or the defect axial length, whichever is the longer.

### 2.3.3 Material Properties

The following material properties for use in a Level 3 assessment shall be determined.

1. Young's Modulus, thermal expansion coefficient, thermal conductivity, density and Poisson's ratio.
2. Monotonic true stress versus true strain curve. A representative true stress versus true strain curve can be constructed from tensile test data from round bar specimens or converted from engineering stress versus strain curves obtained from standard tensile tests.

A non-linear, large-deformation finite element analysis requires the use of a true stress/true strain relationship. This should extend at least to the point corresponding to the material's ultimate tensile strength. A true stress/true strain curve can be constructed from true stresses and strains measured from a tensile test on a round bar specimen at a temperature relevant to the operating condition.

### 2.3.4 Loads

All loads on the corroded pipeline shall be considered in the assessment.

### 2.3.5 Boundary conditions

Appropriate boundary conditions shall be applied to the FE model. To apply appropriate boundary conditions to the pipe requires an understanding of the general deformation of the damaged pipe under its specific operating condition and the experience in idealization of structural supporting conditions. For buried or anchored straight pipeline sections, the boundary conditions should be such as to restrict axial displacement of the pipe.

### 2.3.6 Non-Linear Stress Analysis

The FE analysis shall be performed using a verified software program with the capability to allow modeling of non-linear material properties and non-linear geometry. The von Mises yield function and associated flow rule shall be used in the analysis. If the pipeline is subjected to quasi-static loading, then isotropic hardening should be selected.

### 2.3.7 Failure Prediction

The stress and strain fields in the pipeline at the location of the corrosion defect should be examined. A method for predicting the failure pressure has been developed and validated against 93 ring tension and vessel burst test results. These results have shown that the failure pressure can be determined from the von Mises equivalent stress through the minimum ligament of the defect. The failure pressure is considered to be the pressure that causes the average stress in the ligament to be equal to the material's tensile strength from a uniaxial tensile test.

A narrow defect in a pipeline may result in the generation of high stress gradients across the remaining ligament, which can result in crack initiation well before the gross yield of the remaining ligament. This may consequently lead to failure by crack growth without significant necking. In this case, the above failure criterion may not be applicable. Examples of narrow defects are those with circumferential widths less than the wall thickness or 10 % of the defect axial length.

[References: (1) Anon., 'Guide To Methods For Assessing the Acceptability of Flaws in Metallic Structures', BS 7910:2005, Incorporating Amendment No. 1, BSI 2007, 28 September 2007; (2) Batte, A.D, and Fu, B., 'An Overview of Advanced Methods for the Assessment of Corrosion in Linepipe', Offshore Technology Report, OTO 1999 051, UK Health and Safety Executive, August 1999].

# 3 Low Toughness Pipelines

Assessment methods, such as ASME B31G, Modified ASME B31G, RSTRENG and LPC, described in this Guidance Document are all based on the assumption that the corroded pipeline fails by plastic collapse. The test data used to validate the methods generally shows that the materials were on the upper shelf of the Charpy transition curve, where ductile behavior is expected. In a few cases the material may have been in the upper part of the transition region, but the absorbed energy values were above typical acceptance levels in pressure vessel codes.

There are some older, vintage pipelines, which operate with the material in the ductile / brittle transition region of the Charpy transition curve, or even on the lower shelf. It is also possible that under fault conditions, a pipeline which is normally operating on the upper shelf could be temporarily in the transition region. Under these conditions, the failure criteria which assume ductile behavior may not apply and could be non-conservative. To address this uncertainty a program of burst tests on vintage, low toughness pipe was undertaken. This was supplemented by analytical study. Based on the results of these studies, existing assessment methods such as ASME B31G, Modified ASME B31G, LPC and RSTRENG are considered to be valid for pipelines with transition temperatures up to +104 °F (+40 °C). As buried pipeline temperatures are unlikely to be below -4°F (-20 ºC), it is judged likely that existing assessment methods, such as the ASME B31G, Modified ASME B31G, RSTRENG and LPC-1, remain conservative for the assessment of corrosion defects in vintage, low toughness pipelines. It is also considered that the results from ongoing investigations into the failure behavior of corrosion defects subjected to combined internal pressure and external loading will remain valid for older low toughness pipelines.

[References: (1) Martin, M., and Andrews, R.M., 'Project #153L - The Remaining Strength of Corroded Low Toughness Pipe', Germanischer Lloyd Report R9247 Issue 2.0, June 2008].

# 4 Combined Loading

ASME B31G, RSTRENG, LPC and other methods were derived using burst tests conducted on pipe with real or simulated (machined) defects subjected to only internal pressure loading. In the vast majority of cases, internal pressure loading is the main loading mechanism on a pipeline. However, there may be instances when pipelines could also be subjected to both internal pressure loading and significant external loading. For onshore pipelines, these additional loads could be as a result of ground movement due to landslides, mining subsidence, frost heave, thaw settlement, or even seismic activity. In the case of offshore pipelines the formation of free spans may impose significant bending loads. For instance, seabed scour can lead to the development and growth of free spans of pipelines resting on the seabed, particularly if they are not trenched. In these cases, assessing the remaining strength of a corroded pipeline using ASME B31G, RSTRENG, etc. may be inappropriate.

The Recommended Practice, DNV RP-F101 provides guidance for assessing corroded pipelines subjected to combined internal pressure and environmental loading. However, this recommended practice was validated using a database of 12 burst tests on only one pipe diameter and material grade (12¾-inch, grade X52) containing simulated (machined) grooves. In this Guidance Document, failure locus diagrams are provided for assessing patch, groove or pit defects. Normalized failure locus diagrams for different defect geometries have been developed using numerical analyses, validated by full scale burst testing. These diagrams have been developed assuming that failure of a corroded pipeline can occur in one of three ways:

1. Local failure of the pipe at the remaining ligament
2. Global yielding of the pipe cross section

3. Global instability or buckling

This assessment procedure shall only be used to assess pipelines with single, isolated areas of corrosion subject to internal pressure loading and either an external bending moment or a compressive axial force. Expert advice shall be sought when assessing closely spaced defects which may interact, or if the pipeline is subject to cyclic loading.

## 4.1 Assessment Procedure

STEP 1 Determine the dimensions, shape and orientation of the defect to be assessed.

STEP 2 Calculate the failure pressure of the corroded pipeline under internal pressure loading only, using the methods described in Section 2.

STEP 3 Calculate $\alpha$, $I$, $P_o$, $M_o$, $F_o$ using Equations [15] to [19].

STEP 4 Determine the magnitude of the applied external bending moment, $M_A$, or axial compressive force, $F_A$ on the pipeline.

STEP 5 Calculate ($M_A/M_o$) or ($F_A/F_o$) and ($P_A/P_o$) as appropriate.

STEP 6 Select the failure locus diagram from Figure 4.1-1 to 4.1-8 as appropriate.

STEP 7 Plot the point ($M_A/M_o$) or ($F_A/F_o$) and ($P_A/P_o$) on the failure locus diagram. A point that lies inside the failure locus means that the defect the corroded pipeline is safe. Conversely a point that is outside the failure locus means that the defect is unsafe, as shown in Figure 4.1-1.

STEP 8 The estimated failure pressure, $P_f^{comb}$, of the corroded pipeline is calculated by determining the value of $P_A$ using the ratio ($P_A/P_o$) at the point of intersection with the failure locus, as shown in Figure 4.1-1.

STEP 9 Determine the minimum predicted failure pressure, from $P_f$ or $P_f^{comb}$, whichever is the lower.

STEP 10 The safe operating pressure, Ps, of the corroded pipeline is calculated using an appropriate factor of safety: Ps = SF(min($P_f$, $P_f^{comb}$)).

$$\alpha = \frac{D_o}{2t} \qquad [15]$$

$$I = \frac{\pi}{64}\left(D_o^4 - D_i^4\right) \qquad [16]$$

$$P_0 = \frac{(2\alpha - 1)SMYS}{(\alpha - 1)\sqrt{3\alpha^2 - 3\alpha + 1}} \qquad [17]$$

$$M_0 = \frac{2I(SMYS)}{D_o} \qquad [18]$$

$$F_0 = \frac{\pi}{4}\left(D_0^2 - D_i^2\right)SMYS \qquad [19]$$

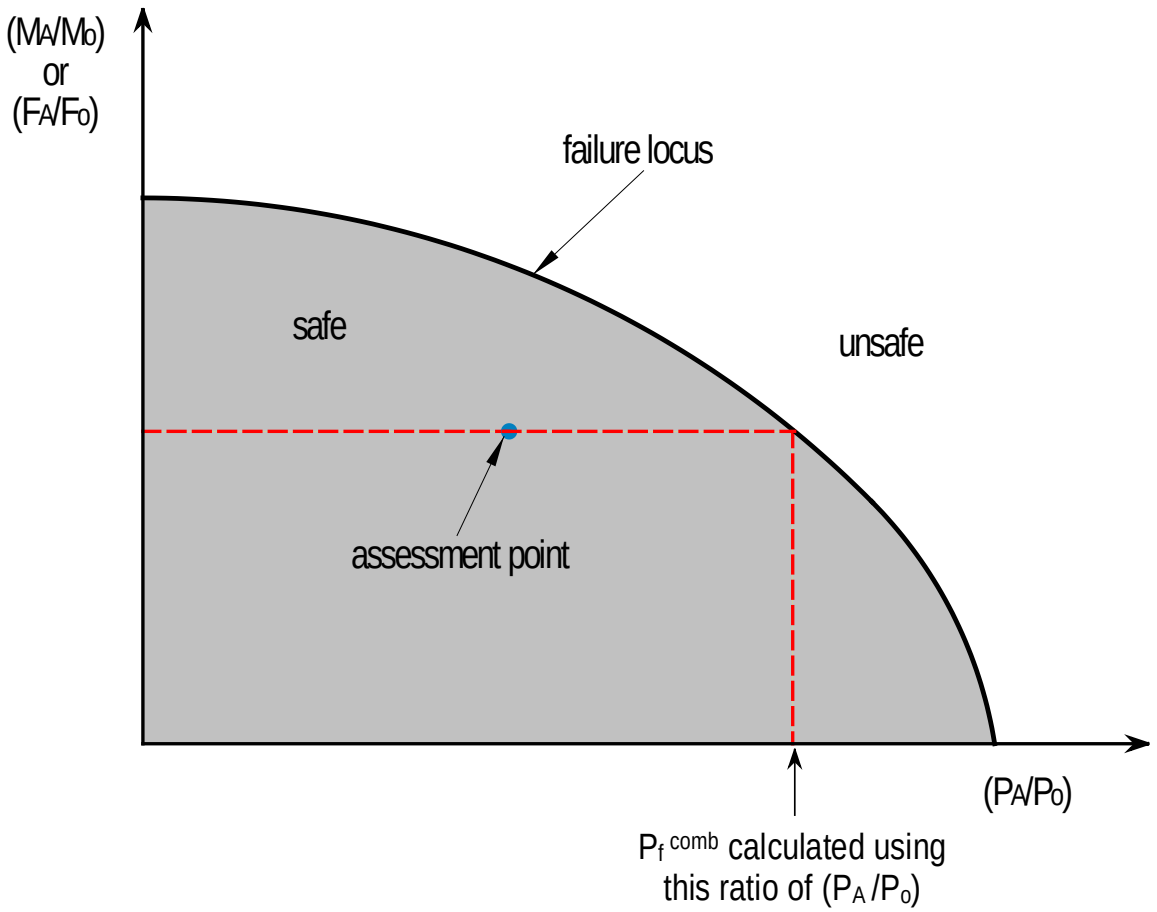


Figure 4.1-1 Use of Failure Locus Diagram to Assess a Corroded Pipeline Subject to Combined Loading

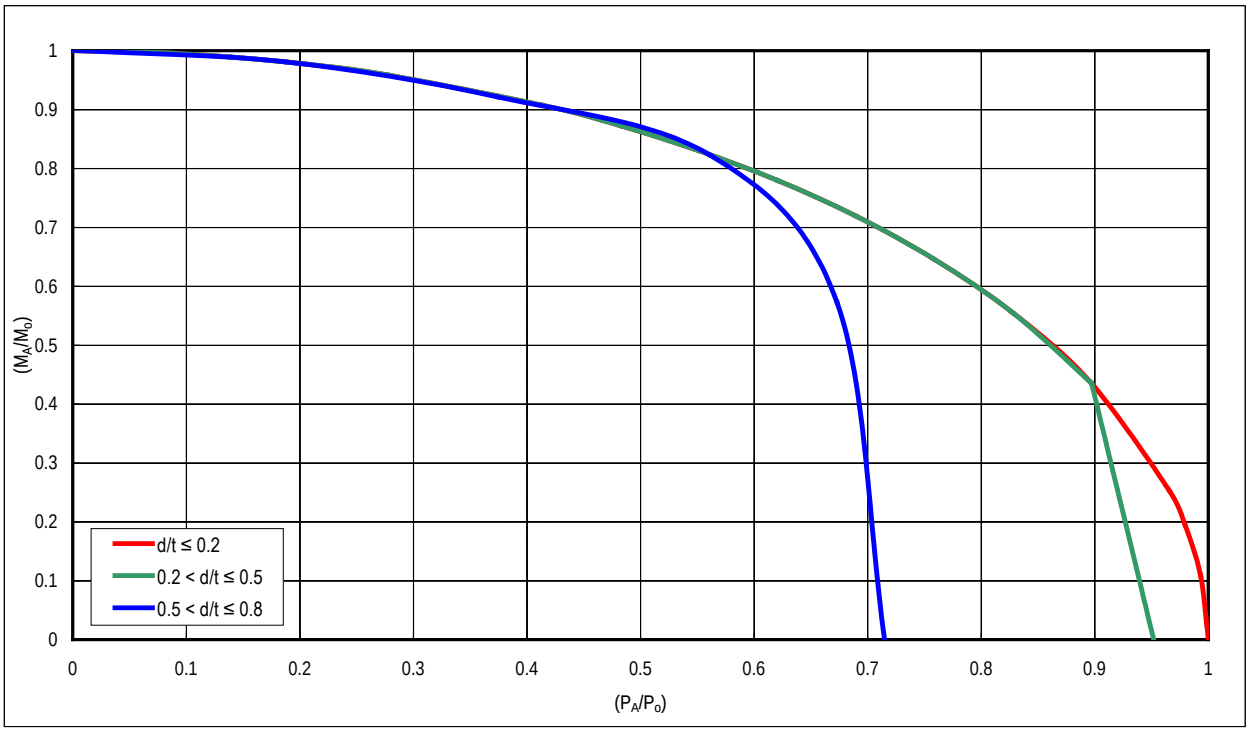


Figure 4.1-2 Combined Internal Pressure and Bending Moment - Failure Locus for a Patch Defect

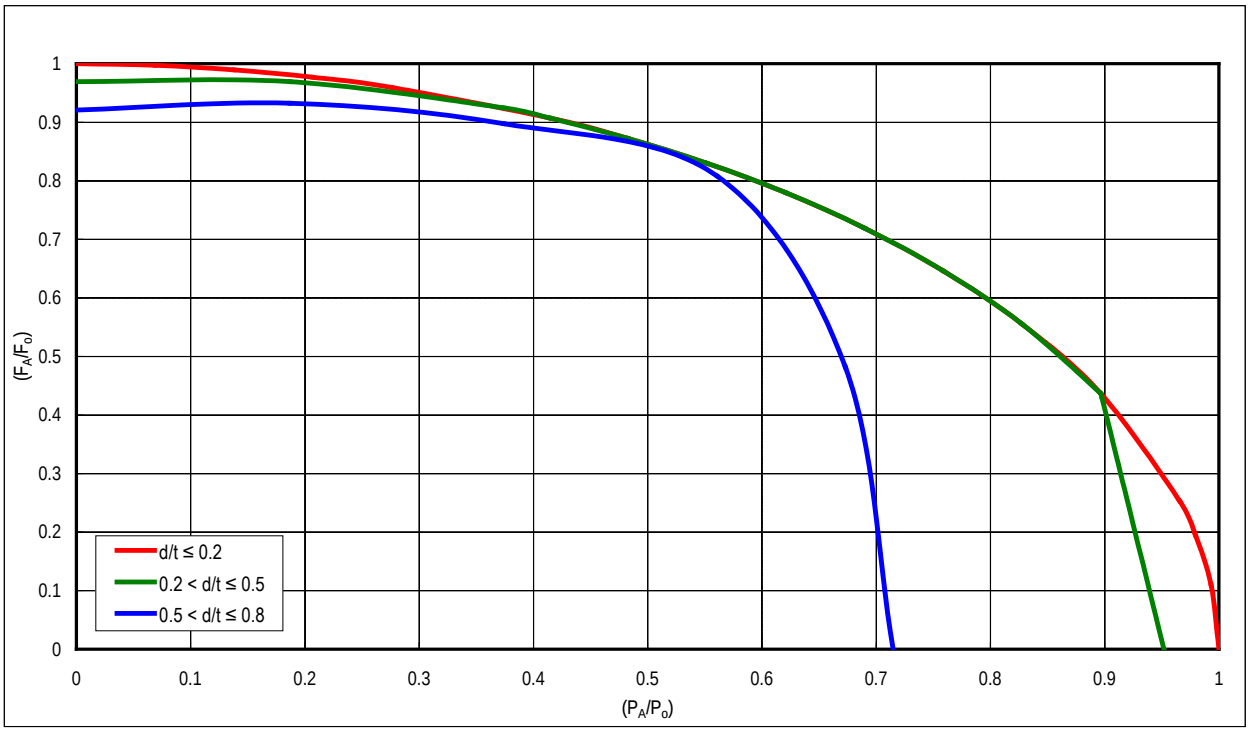


Figure 4.1-3 Combined Internal Pressure and Compressive Load - Failure Locus for a Patch Defect

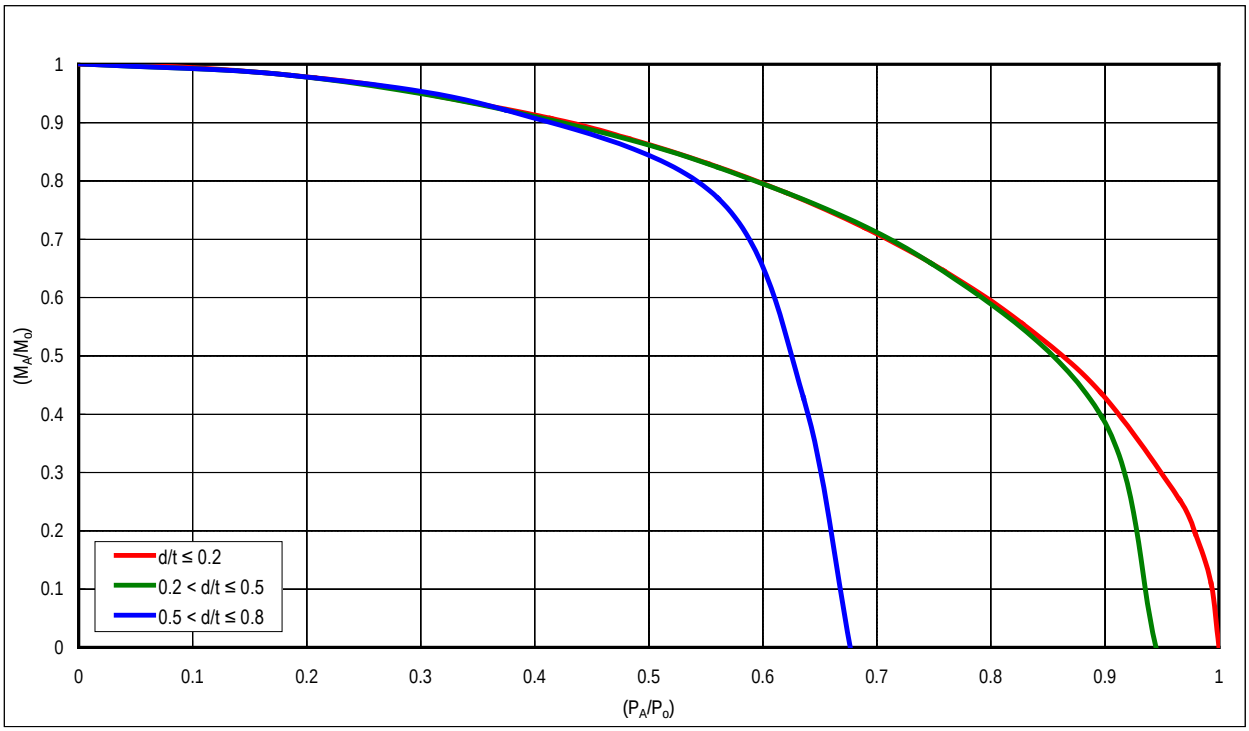


Figure 4.1-4 Combined Internal Pressure and Bending Moment - Failure Locus for an Axial Groove Defect

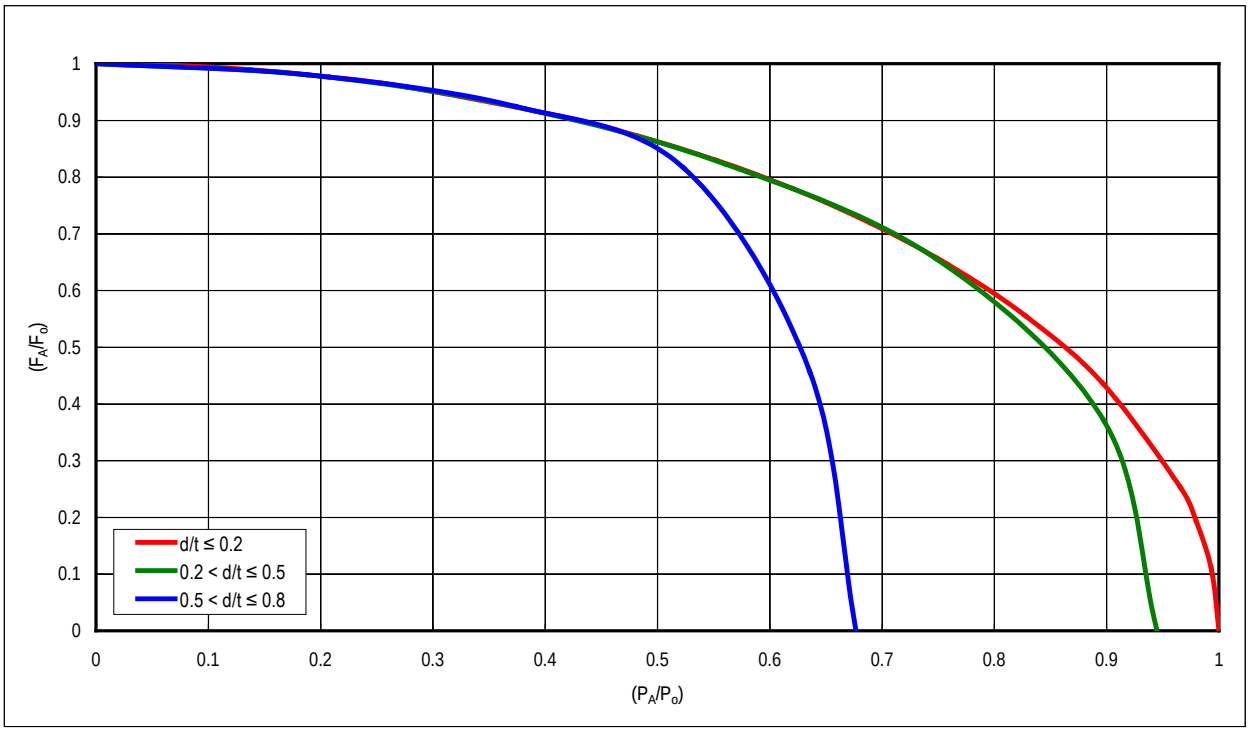


Figure 4.1-5 Combined Internal Pressure and Compressive Load - Failure Locus for an Axial Groove Defect

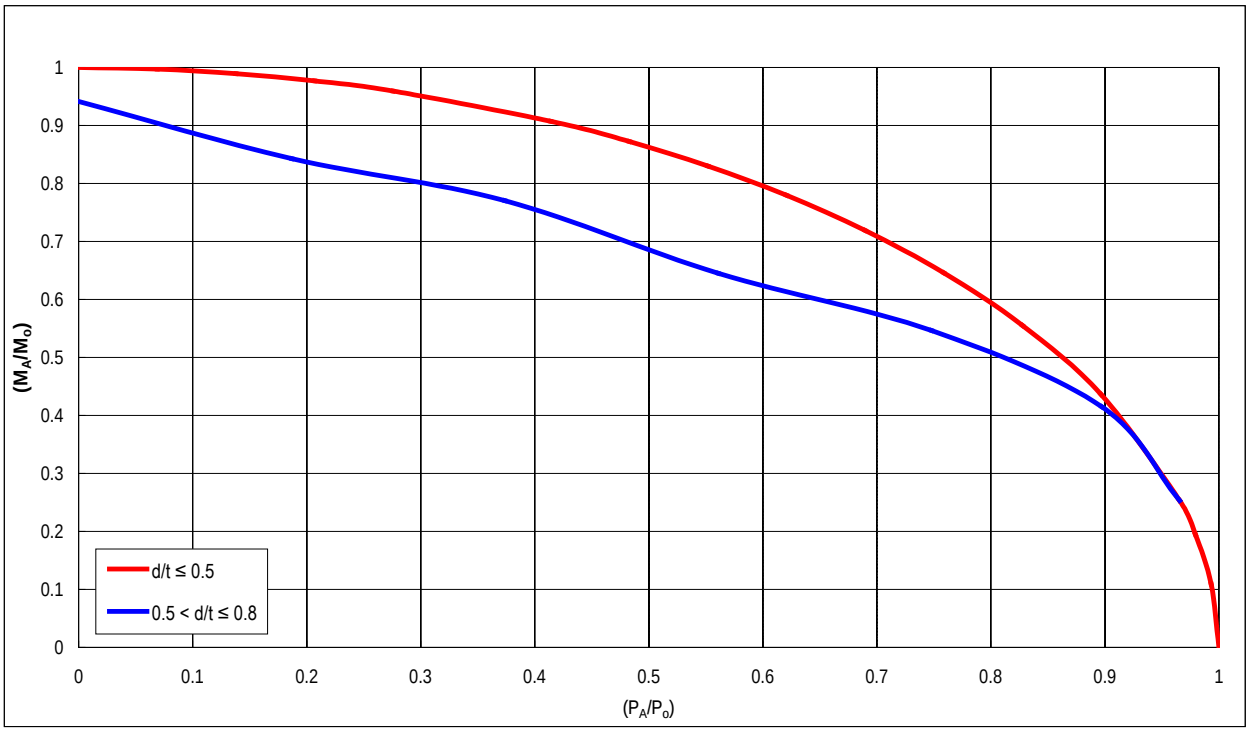


Figure 4.1-6 Combined Internal Pressure and Bending Moment - Failure Locus for a Circumferential Groove Defect

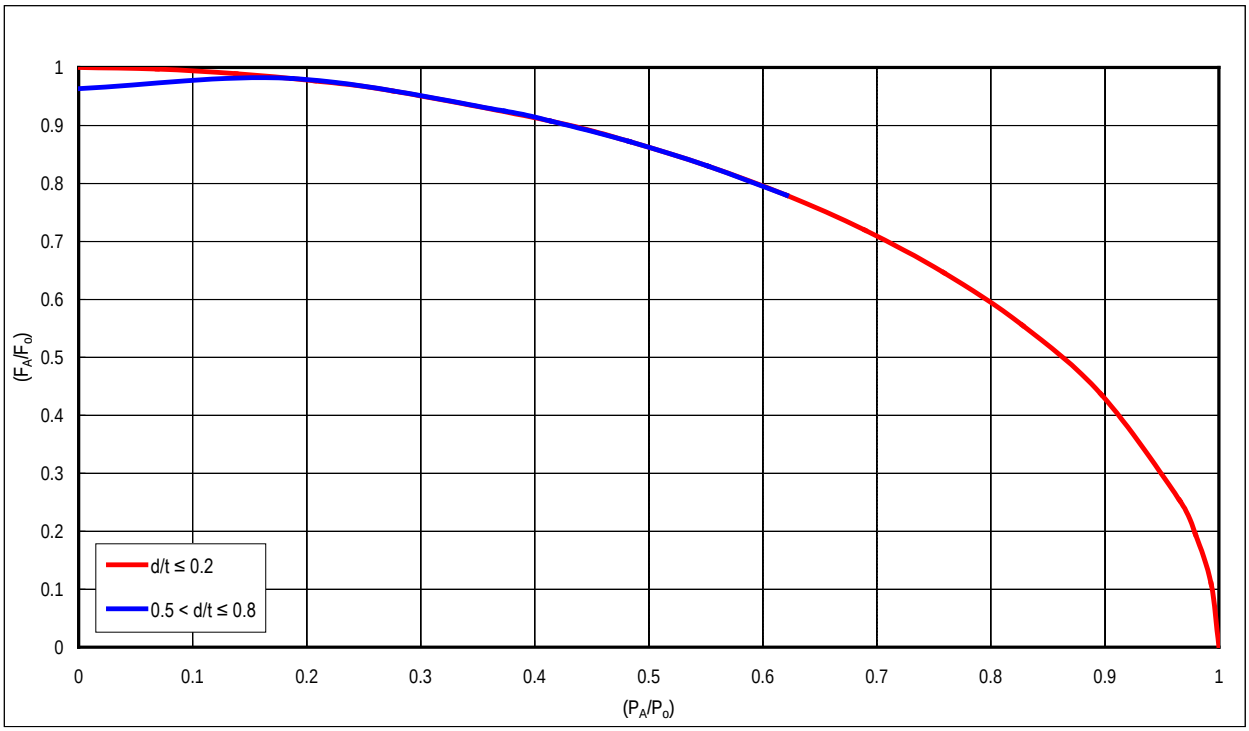


Figure 4.1-7 Combined Internal Pressure and Compressive Load - Failure Locus for a Circumferential Groove Defect

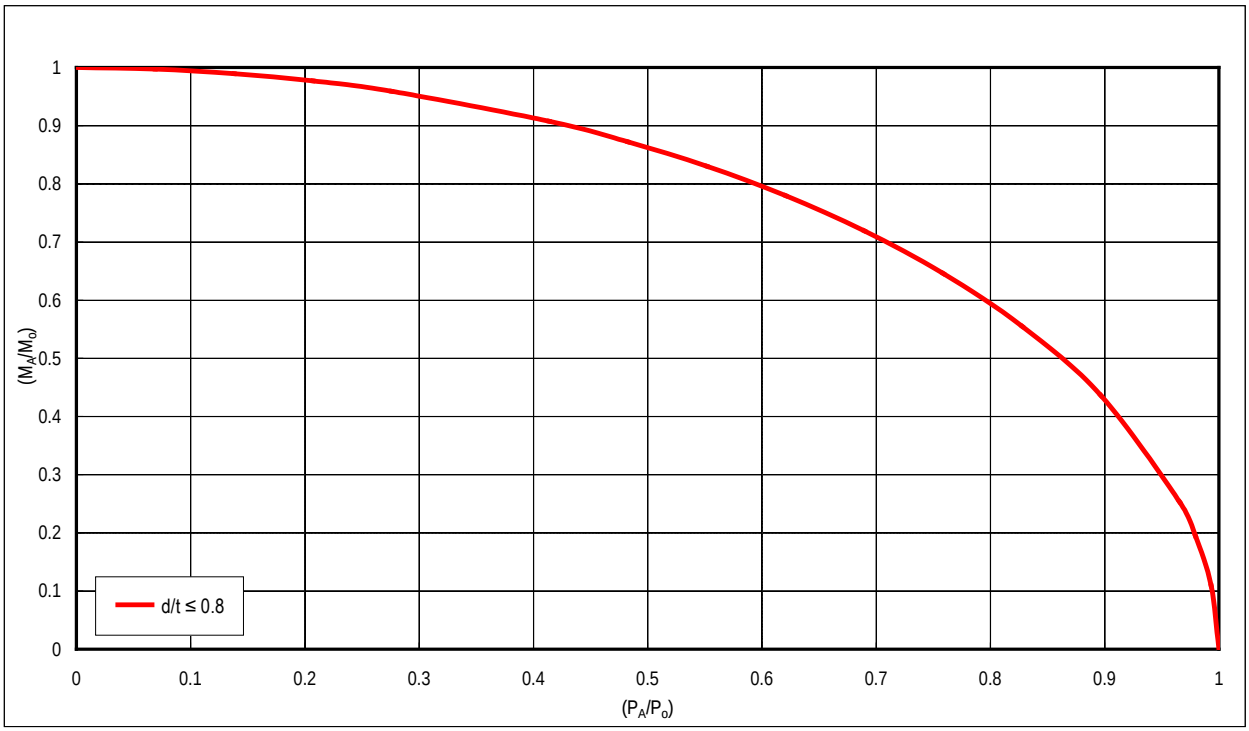


Figure 4.1-8 Combined Internal Pressure and Bending Moment - Failure Locus for a Pit Defect

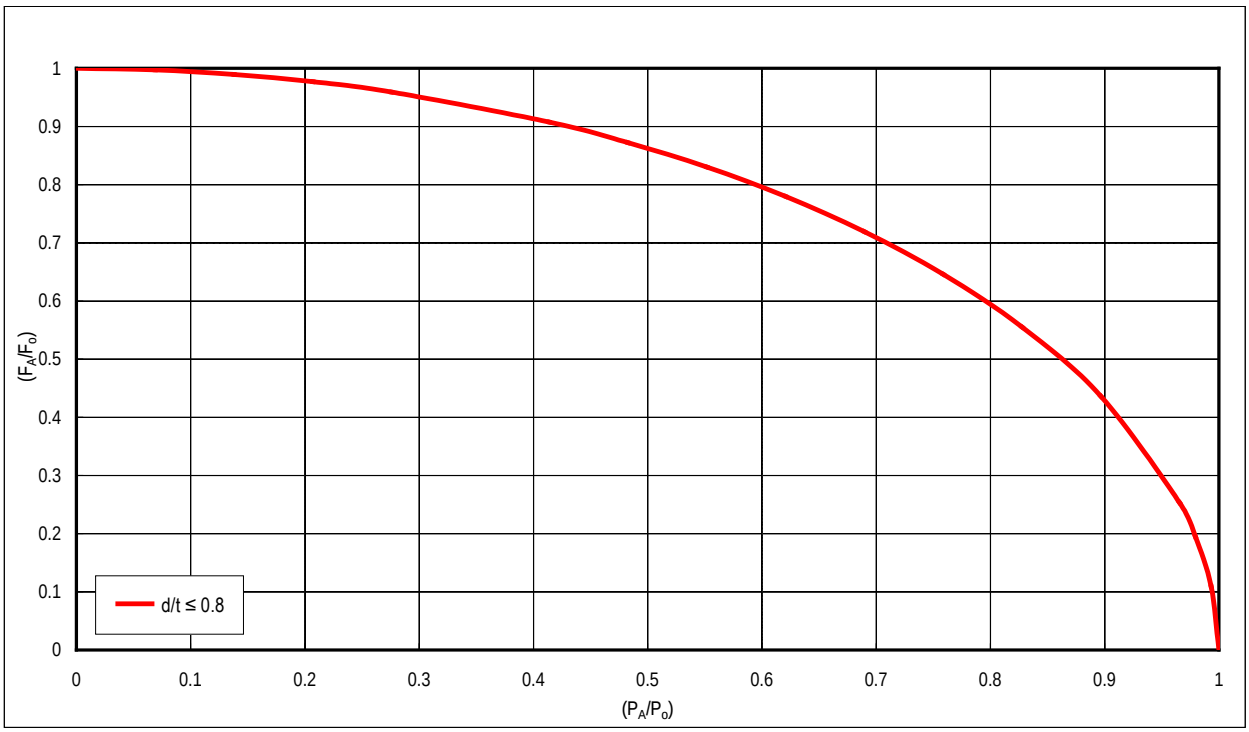


Figure 4.1-9 Combined Internal Pressure and Compressive Load - Failure Locus for a Pit Defect

[References: (1) Liu, J., Chauhan, V., Ng, P., Wheat, S., and Hughes, C., 'Project #153J - Remaining Strength of Corroded Pipe Under Secondary (Biaxial) Loading', Germanischer Lloyd Report R9068 Issue 3.0, August 2009]; (2) Liu, J., Mortimer, L., and Wood, A., 'Project #153H - Corrosion Assessment Guidance for High Strength Steels (Phase 2)', Germanischer Lloyd Report 7930, Issue 3.1, November 2009].

# 5 Cyclic Pressure Loading

There are numerous established methods for assessing the remaining strength of a corroded pipeline but no guidance has been developed to date for assessing the performance of a corroded pipeline under cyclic pressure loading. This is of potential concern to operators where the corroded pipeline is subjected to significant pressure variations, for example, where there is a demand for linepack[3] storage and liquid pipelines. It is possible that a corrosion defect could be assessed as acceptable at the MAOP of the pipeline, but even if the corrosion damage is resolved by coating repairs or the introduction of corrosion inhibitor, failure by fatigue due to internal pressure fluctuations remains a credible threat.

Predicting the effect of a corrosive environment on fatigue life is complex. For pipelines with significant metal loss, there is a further complication in that the stress raising effects of the corrosion defect would reduce life as this area is exposed to higher stresses (in addition to the environment). Since the stress raising effect is present, regardless of whether the corrosion damage has been arrested and recoated, it is considered that an assessment method for pipeline corrosion defects should include both effects.

## 5.1 Assessment Method

The approach for undertaking a fatigue assessment of the remaining life of an area of corrosion on a pipeline is summarized in Figure 5.1-1.

[3] Linepack is the term for storage of gas in transmission pipelines. By raising and lowering the pressure in a pipeline segment, an operator can use the segment to store gas during periods when there is less demand, allowing supply and demand flow variations to be managed efficiently.

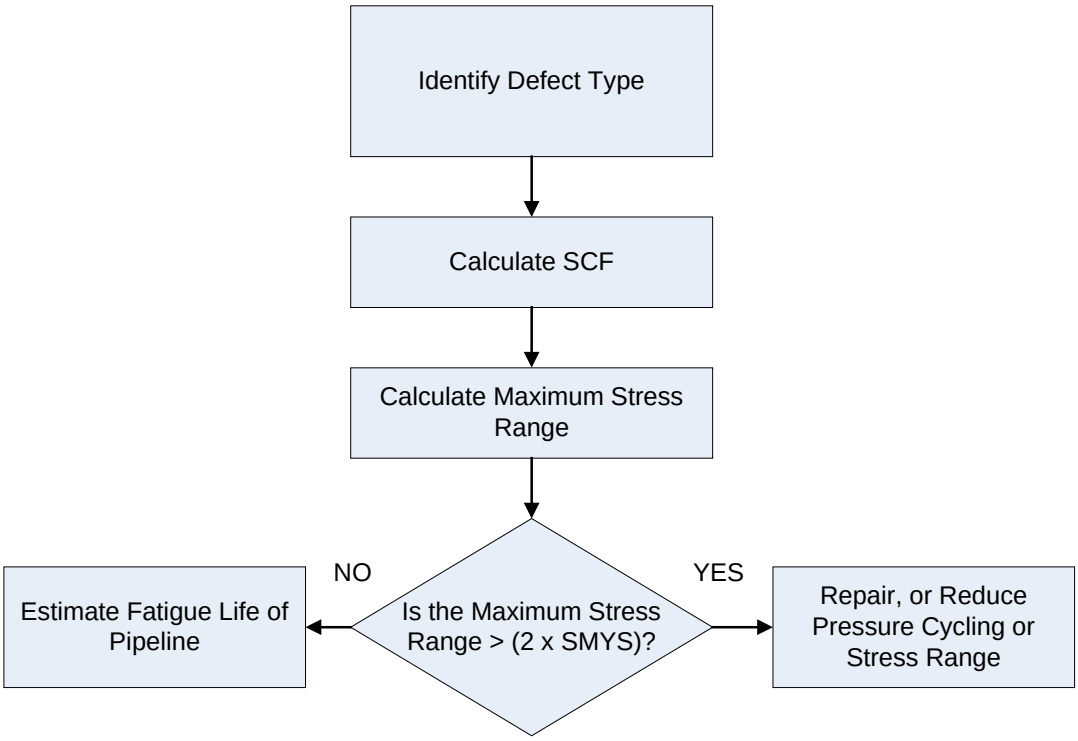


Figure 5.1-1 Cyclic Pressure Loading Assessment Algorithm

The fatigue life assessment method is based on the *S-N* approach in BS 7608. The fatigue life of a pipeline with a corrosion defect shall be calculated using:

$$LogN = LogC_o - \delta\sigma - mLogS_r \qquad [20]$$

In the absence of a pipeline specific *S-N* curve (i.e. an *S-N* curve specific to the particular material and environment) the Class B fatigue design curve from BS 7608 shall be used. The constants $C_o$, $\sigma$ and $m$ are 24.01562, 0.1821 and 4.0 respectively[4].

To take account of the stress raising effect of the corrosion defect, the $S_r$ term shall be multiplied by an SCF. The equations below are split into two categories: those dominated by a hoop stress component and those dominated by an axial stress component.

The hoop SCFs are calculated using the following equations:

$$SCF_{HOOP} = A_6\left(A_1 + \left[A_2(CD)^2\left(\frac{Ln(25.4*ACL)}{Ln(25.4*CCL)}\right)^2\right] + \left[A_3\frac{CD^2}{\left(\frac{CCL}{\sqrt{Dt}}\right)}\right] + \left[A_4\frac{(CD)^2 ACL}{CCL}\right] + \left[A_5(CD)^2 Ln\left(\frac{CCL}{ACL(CD)}\right)\right]\right) \qquad [21]$$

for CCL≤4" and CD≤0.6

[4] The coefficient $C_o$ has been modified from that recommended in BS7608 from 15.3697 to 24.01562 to permit input of stress in US Customary units of lb/in$^2$ (psi).

$$SCF_{HOOP} = A_6\left(A_1 + \left[A_2(CD)^2\left(\frac{Ln(25.4*ACL)}{Ln(100)}\right)^2\right] + \left[A_3\frac{(CD)^2}{\left(\frac{4}{\sqrt{Dt}}\right)}\right] + \left[A_4\frac{(CD)^2 ACL}{4}\right] + \left[A_5(CD)^2 Ln\left(\frac{4}{ACL(CD)}\right)\right]\right) \quad [22]$$

for CCL>4" and CD≤0.6

The axial SCFs are calculated using the following equation:

$$SCF_{AXIAL} = B_5\left(B_1 + \left(B_2 CD\left(Ln\left(\frac{CCL}{ACL}\right)\right)\right) + \left(B_3 CD\left(Ln\left(\frac{ACL}{\sqrt{Dt}}\right)\right)\right) + B_4(CD)^2\right) \quad [23]$$

for CD≤0.6

The terms ACL and CCL are as defined in Figure 5.1-2. Note that ACL and CCL are half lengths, and CD is the normalized defect depth (d/t).

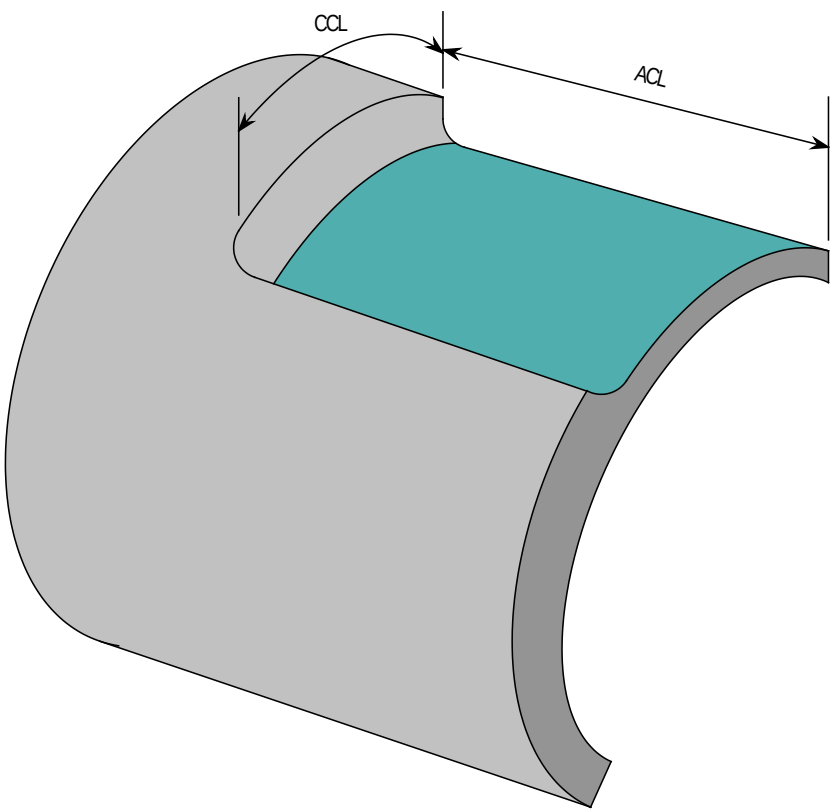


Figure 5.1-2 Definition of ACL and CCL

The terms $A_1$ to $A_6$ and $B_1$ to $B_5$ are equation fitting constants, given by:

| | | | |
|---|---|---|---|
| $A_1$ | 1.40 | $B_1$ | -0.64 |
| $A_2$ | 7.40 | $B_2$ | 0.58 |
| $A_3$ | -0.54 | $B_3$ | -2.29 |
| $A_4$ | -0.37 | $B_4$ | 1.31 |

| | | | |
|---|---|---|---|
| $A_5$ | 0.28 | $B_5$ | 1.10 |
| $A_6$ | 1.18 | | |

When the half 'circumferential corrosion length', CCL≥2" and the half 'axial corrosion length', ACL≤20.75" the SCF can be driven by either the hoop or axial stress. Outside of this region the SCF is dominated by the hoop stress. For an area of corrosion that has dimensions ACL and CCL in the hoop/axial boundary region, the highest SCF returned from the two equations shall be used to provide a conservative assessment.

Corrosion defects of depths up to 60% (CD = 0.6) of the nominal pipe wall can be assessed. Pipelines with corrosion defects greater than 60% of the pipe wall shall be repaired.

[References: (1) Swankie, T., Robinson, M., Liu, J., Crossley, J., and Morgan, G., 'Project #153K - The Assessment of Corrosion Damage in Pipelines Subjected to Cyclic Pressure Loading', Germanischer Lloyd Report R8928 Issue 1.0, January 2009; (2) Swankie, T., 'Project #153K - The Assessment of Corrosion Damage in Pipelines Subjected to Cyclic Pressure Loading. Addendum to GL Report R8928, Issue 1.0', Germanischer Lloyd Report 9474, Issue 1.0, December 2009; (3) BS 7608:1993 (Incorporating amendment No.1), 'Code of practice for fatigue design and assessment of steel structures', British Standards Institution, London, UK, 1993].

# 6 High Strength Pipelines

Use of ASME B31G, Modified ASME B31G, RSTRENG and LPC may be inappropriate for higher strength pipelines. A particular concern is the high yield strength to tensile strength (SMYS/SMTS or $S_{YT}/S_{UT}$) ratio of high strength steels. For cold expanded pipe, API 5L/ISO 3183 states that the yield to tensile ratio should not exceed 0.93 for Grade X80 pipe and 0.97 for Grade X100 pipe.

Burst tests conducted on linepipe of strength grade X80 and X100 with simulated (machined) corrosion defects show that existing assessment methods predict safe operating pressures lower than the actual burst pressure from tests. However, care has to be taken to ensure that the flow stress used is not greater than the specified minimum ultimate tensile strength (*SMUT*). For assessing the remaining strength of pipelines of strength grade X80 and X100, the flow stress shall be defined by $S_{flow}$ = (SMYS+SMTS)/2 when using the methods described in Section 2.

[References: (1) Chauhan, V., and Crossley, J., 'Project #153H - Corrosion Assessment Guidance for High Strength Steels (Phase 1)', Germanischer Lloyd Report R9017, Issue 4.0, August 2009; (2) Liu, J., Mortimer, L., and Wood, A., 'Project #153H - Corrosion Assessment Guidance for High Strength Steels (Phase 2)', Germanischer Lloyd Report 7930, Issue 3.1, November 2009; (3) Chauhan, V., and Brister, J., 'A Review of Methods for Assessing the Remaining Strength of Corroded Pipelines', Germanischer Lloyd Report 6781, Issue 6.1, November 2009].

# 7 Corrosion Associated with Girth and Long Seam Welds

Industry recognized methods for assessing the integrity of a pipeline with corrosion damage are limited to corrosion of the pipe body, remote from a weld. The following guidelines have been developed based on a review of the available data from full-scale tests, laboratory tests, and in-service failures involving corrosion on weld seams, for both girth welds and longitudinal seams.

## 7.1 Assessment Method

The approach for undertaking an assessment of the effect of corrosion damage at a seam or girth weld is shown in Figure 7.1-1.

Use of this guidance is dependent on the following conditions being satisfied:

- The weld is free of crack-like defects
- The mechanical properties of the weld are not less than those of the pipe body
- The fracture properties of the weld and pipe body are adequate to ensure that failure is controlled by plastic collapse
- The service and loading remains consistent with the original design

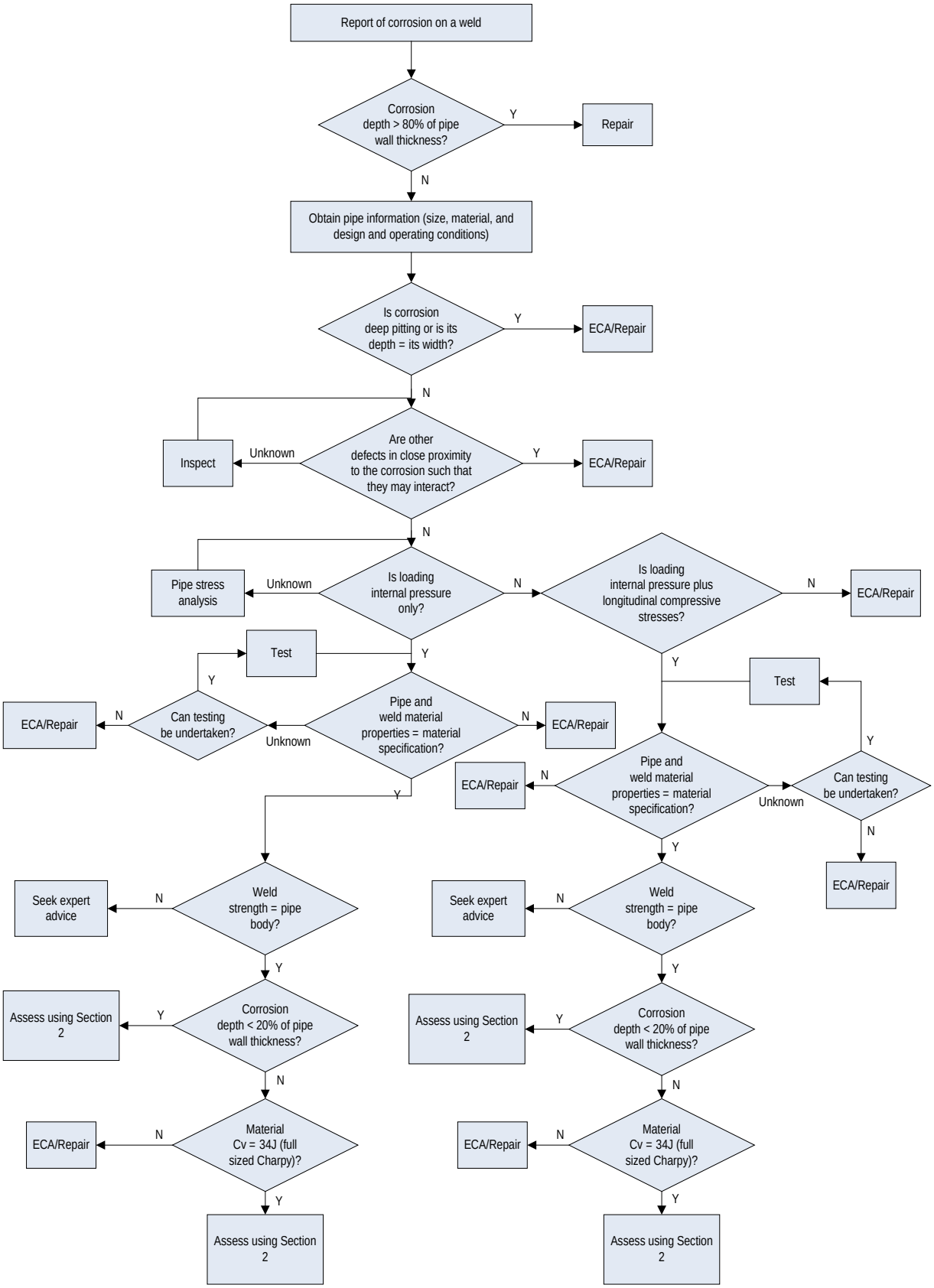


Figure 7.1-1 Algorithm for Assessing Corrosion with Girth and Long Seam Welds

[References: (1) Leis, B.N., Clark, E.B., Zhu, X.K., Galliher, R.D., 'Guidelines for Assessing Corrosion Associated with Girth and Long Seam Welds', Battelle Final Report Number GRI-04/0119 prepared for Gas Technology Institute (Contract Number 8521), October 2004].

# 8 Remaining Life Assessment

Corrosion is a time dependent threat to a pipeline. If the corrosion cannot be arrested, then the assessment shall consider the consequences of further growth to ensure that defects will not attain critical dimensions prior to conducting a scheduled repair or before the next scheduled inspection is due. This assessment shall consider representative internal and external corrosion growth rates; these will depend on the environment in which the pipeline operates and the product being transported. Detailed guidance for conducting a remaining life assessment is beyond the scope of this Guidance Document. For cases where a remaining life assessment is required, then the user should refer to API 579-1/ASME FFS-1, API 570 and ASME B31.8S for guidance.