INTEGRITY MANAGEMENT PROGRAM

In-Line Inspection Program

Defect Assessment & Repair Manual

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Revision Log

REVISION NUMBER	DATE	REVISION SUMMARY	PREPARED/ REVISED BY WITH SIGNATURE AND DATE	APPROVAL AUTHORITY/WITH SIGNATURE AND DATE

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1.0 Purpose

This Defect Assessment and Repair Manual forms part of Pembina Pipeline Corporation's (Pembina) Integrity Management Program (IMP) documentation and is designed to add structure and transparency to field activities related to the assessment and repair of pipeline defects. Implementation of procedures outlined in this document will help ensure current, consistent, and comprehensive integrity management practices across the pipeline systems.

The Defect Assessment and Repair Manual is part of a series of program manuals covering the various aspects of integrity management. Collectively, these manuals assign responsibility and define the "who, what, where, when, why, and how" aspects of Pembina's integrity management program. The manuals work in conjunction with Pembina's "Pipeline Integrity Management Program Overview Document" and our System-System Specific IMP Documents. The Overview document describes the policy, goals, approach, responsibilities, procedures, and programs used by Pembina to ensure the ongoing integrity of our pipeline system while the system-specific documents contain detailed information regarding each pipeline system including hazard evaluations, integrity data analysis, and outlines for long and short-term hazard mitigation strategies.

The Defect Assessment and Repair Manual is developed and maintained by Pipeline Integrity in consultation with Operations. The document includes specific procedures to locate, excavate, assess, and repair pipeline defects identified through Pembina's in-line inspection program. The procedures outlined in the Defect Assessment and Repair Manual are to be utilized during any examination of below grade line pipe, including external corrosion, internal corrosion, mechanical damage and cracking.

2.0 Scope

This document describes the process and procedures necessary to identify critical metal loss, geometry, and crack-like features from in-line inspection data and undertake pipeline field excavations to assess and repair these defects. This document takes into consideration the latest technology and the mandatory requirements of the regulations and standards. Regulations, Industry Standards and Industry Documentation on which this document is based, are detailed in Section 7.0 of this document.

The primary concern of these field procedures is safety. Safety includes, but is not necessarily limited to; preserving the remaining integrity of the damaged, defective or leaking pipeline and ensuring adequate protection for the public, site personnel and property, until the appropriate action(s) have been implemented.

3.0 Training and Qualification Requirements

3.1 Pembina Personnel (General)

a) Pembina personnel responsible for assessing data from high-resolution metal loss, cracking, and deformation in-line inspections should have a good working knowledge of the capabilities and limitations of various high-resolution in-line inspection technologies and the assessment methodologies used to analyze the data collected by the respective tools.

b) Pembina personnel responsible for identifying the features to be excavated and the final sentencing of any defects encountered during the excavations shall be trained in all aspects of pipeline integrity such as in-line inspection data management and defect sentencing. The individual shall have a good working knowledge of non-destructive testing procedures such that effective NDT inspections can be conducted.

c) Pembina personnel responsible for overseeing the excavation program in the field shall be knowledgeable in all aspects of construction and safety. In addition, the individual shall have an awareness of environmental and landowner issues, governing regulations, and have a thorough knowledge of the contracts in place for the project.

3.2 NDT Contractor

a) An NDT Contractor shall have a Level 2 CGSB ticket in the appropriate NDT inspection technique that will be used for the project (i.e. radiography, magnetic particle inspection, dye penetrant, or ultrasonic testing). For SCC investigations preference will be given to contractors with SCC examination experience.

d) The contractor shall be aware and orientate their employees with Pembina's construction and safety requirements, including all jurisdictional requirements and the contractor's construction and safety requirements.

4.0 In-Line Inspection Defect Acceptance Criteria

This section of the procedure specifies an engineering based approach for the review and assessment of high-resolution metal loss, cracking, and deformation in-line inspection data as provided by the in-line inspection vendor(s). The information provided in this section shall enable Pembina to undertake a compliance assessment in order to develop a short term maintenance program (i.e. excavation/repair programs) to ensure the continued integrity, with respect to metal loss, cracks, and deformation features of pipeline segment(s) that have been internally inspected.

Consideration should be given to the expected accuracy of the in-line inspection tool used based on both the vendor specifications and industry experience. If available, comparisons of the inspection results to excavated and recoated/repaired features should be used to evaluate the tool performance before performing the Compliance Assessment.

For each feature type, the Compliance Assessment has been split into two categories:

- features that pose an immediate threat to the pipeline's integrity because of their potential for leak or rupture or indication that third party damage has occurred, and

- features that do not pose an immediate threat but fail regulatory criteria and should be excavated as soon as reasonably practical (ASARP), but within 18 months of receiving the ILI vendor's final report. If additional time is required to excavate these features, a management of change document (MOC) shall be written.

Note: If any features that require immediate excavation are found the operating pressure of the pipeline shall be immediately reduced as per Section 5.3.2 and consideration should be given to undertake leak detection at their location. In those cases in which immediate excavations cannot be completed within 30 days, additional evaluation shall be done to assess the need for a further pressure reduction.

Table 1 contains a summary table for all three types of compliance features and Appendix J contains the field-tool information tables for individual features reported by the respective tools. Sections 4.1, 4.2, and 4.3 describe the procedure for assessing each type of feature.

Pipeline Integrity shall have excavation directives available to the field staff within 30 days of receiving the final report from the in-line inspection vendor.

For compliance criteria which result in an uneconomical number of excavations, the anomalies should be prioritized based on their predicted severity (i.e. depth, burst pressure, or fatigue life), and a sample of anomalies should be excavated in order to assess the severity of the remaining anomalies.

Table 1 Compliance Feature Summary Table

Modified CSA Z662 Field Excavation Program Criteria

Criteria Description	Excavation Schedule	Compliance Criteria #	Number of Unacceptable Defects	Action Taken
Corrosion				
Corrosion metal loss depth ≥ 70% of the nominal wall thickness	Immediate	1		
Corrosion metal loss failing RStreng $_{0.85dL}$/RStreng $_{Eff. Area}$ (Predicted Burst Pressure < 110% of MOP)	Immediate	2		
Corrosion metal loss failing RStreng $_{0.85dL}$/RStreng $_{Eff. Area}$ with a predicted burst pressure below that stated for the appropriate Product and Class Location listed in **Table 3**:	ASARP	3		
For those lines known to be susceptible to internal corrosion, at the discretion of the integrity specialist additional criteria may be adopted which can take into consideration whether the features will grow to a depth of 80% of the pipe wall thickness within three years.	ASARP	4		
Deformation				
Any topside dent:				
With a stress concentrator (metal loss, gouge, groove, arc burn, or crack)[1]	Immediate	5		
> 6mm deep for pipe with an OD ≤ 101.6 mm	Immediate	6		
> 6% of the OD for pipe with an OD > 101.6 mm	Immediate	7		
Any bottomside dent with a stress concentrator (metal loss, gouge, groove, arc burn, or crack)[1]	ASARP	8		
Dent on a mill or field weld:[2]				
> 6 mm deep for pipe with an OD ≤ 323.9 mm	ASARP	9		
> 2% of the OD for pipe with an OD > 323.9 mm	ASARP	10		
Dent in the pipe body:				
> 6mm deep for pipe with an OD ≤ 101.6 mm	ASARP	11		
> 6% of the OD for pipe with an OD > 101.6 mm	ASARP	12		
Wrinkle with a height (measured from peak to valley) of >150% of the pipe nominal wall thickness, a wavelength to height ratio ≤12, a circumferential extent ≥120° of the pipe's circumference or a height (measured from peak to valley) as calculated in **Table 5**.	ASARP	13		
Ovality of the pipeline >6% of the pipeline diameter	ASARP	14		
Cracks[3]				
Crack-field and crack-like features with predicted depth greater than the deepest depth bin reported by the ILI tool (include notch-like and weld anomalies if their depths are reported)	Immediate	15		
Crack-field, crack-like, notch like, and weld anomaly features with a predicted burst pressure <110% of MOP	Immediate	16		
Preferential seam weld corrosion > 40% of the nominal wall thickness or assessed as a crack with a predicted burst pressure <110% MOP	Immediate	17		
Crack-field and crack-like feature located in a dent (include notch-like and weld anomalies if their depths are reported)	ASARP	18		
Crack-field or crack-like feature with predicted burst pressures less than those stated for the appropriate Product and Class Locations stated in **Table 6**[4] (include notch-like and weld anomalies if their depths are reported)	ASARP	19		
Laminations which run into either the longitudinal weld or girth weld[5]	ASARP	20		
Corrosion metal loss containing cracks	ASARP	21		
Other				
Gouges, grooves, and arc burns	ASARP	22		
Any weld containing an imperfection that fails an engineering assessment	ASARP	23		
Any other condition which, in the opinion of the ILI specialist, requires remediation	ASARP	24		

[1] To meet criteria, metal loss, cracking or stress risers must be within +/-30 cm of a dent.

[2] Dents must be within +/-30 cm of a girth weld or +/-5 cm of a longseam weld.

[3] Preferential seam weld corrosion shall be assessed as a crack

[4] The length of crack-field and crack-like feature(s) to be used in the critical flaw calculations shall be the "maximum interlinked crack length" reported by the in-line inspection vendor, if provided, otherwise it shall be the "total length of the crack

[5] The laminations/inclusions reported near (within 50 mm of) longitudinal seam weld and girth welds.

4.1 Metal Loss In-Line Inspection Assessment

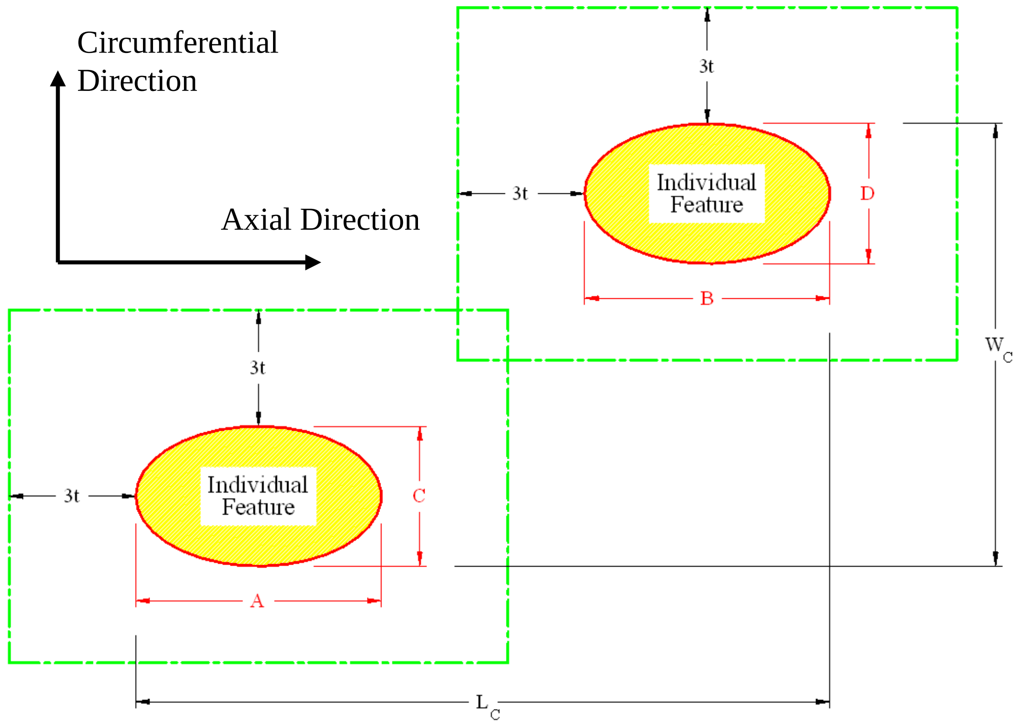
The purpose of this section is to specify an engineering based approach for assessing the short-term acceptability of features detected by magnetic flux leakage (MFL) or ultrasonic wall thickness measurement metal loss in-line inspection tools.

4.1.1 Interaction Criteria for Metal Loss Features

The in-line inspection vendors shall use two different levels of interaction criteria when analyzing their metal loss inspection data. The first level of interaction shall involve interacting individual metal loss features, to form clusters. The second level of interaction shall involve interacting the independent individual metal loss features and clusters identified through the Level 1 interaction, to form groups.

4.1.1.1 Level 1 Interaction Criteria (Clusters)

In the Level 1 interaction, individual metal loss features shall be considered to interact, and form clusters, if they are spaced at an axial and circumferential edge to edge distance of less than or equal to six times the pipe's nominal wall thickness (6t) or 25 mm, whichever is greater. As illustrated in Figure 1, to determine the spacing, the dimensions of the individual metal loss features shall be expanded in both axial directions and circumferential directions by 3t or 12.5 mm, whichever is greater. If two or more expanded metal loss features touch or overlap, they shall be deemed as a cluster. The final cluster dimensions shall be as described in Figure 1.

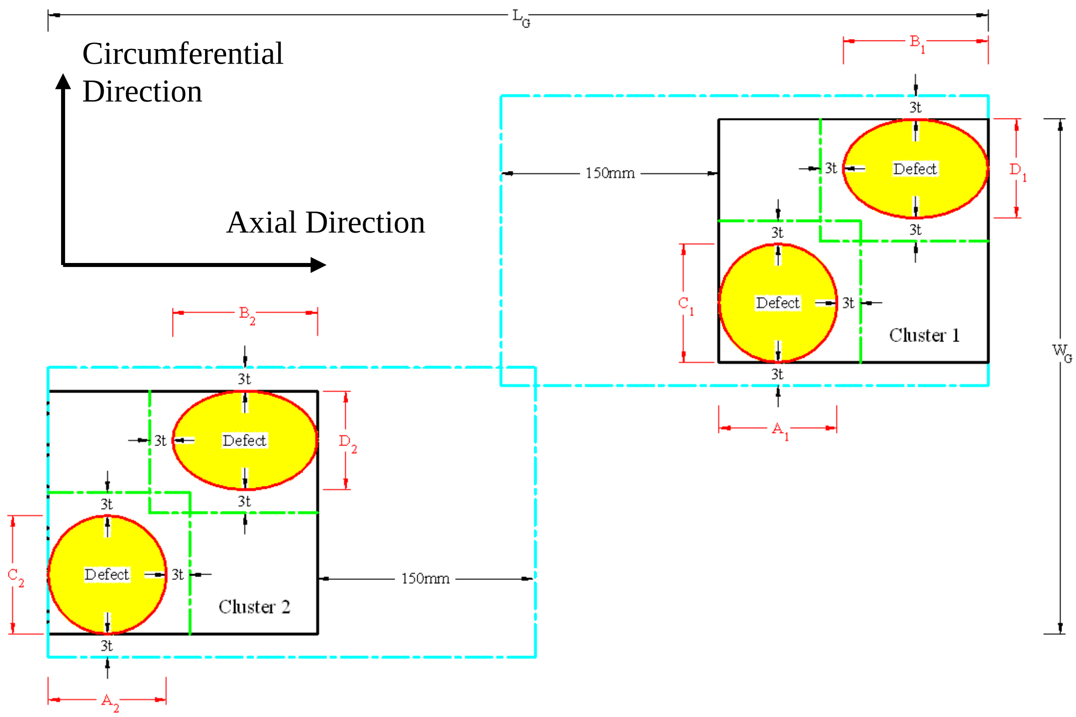


Cluster Dimension
Cluster Length = L_C
Cluster Width = W_C

Figure 1 Level 1 Interaction - Individual Features Forming a Cluster

4.1.1.2 Level 2 Interaction Criteria (Groups)

In the Level 2 interaction, independent individual metal loss features and clusters are considered to interact and form groups, if they are spaced at an axial distance of less than or equal to 300 mm and spaced at a circumferential distance of less than or equal to 6t or 25 mm, whichever is greater. As illustrated in Figure 2, to determine the spacing, the individual metal loss features or clusters shall be expanded in both axial directions by 150 mm and in both circumferential directions by 3t or 12.5 mm, whichever is greater. If two or more expanded features or clusters touch or overlap, they shall be deemed a group. The final group dimensions shall be as described in Figure 2.



Group Dimension
Group Length = L_G
Group Width = W_G

Figure 2 Level 2 Interaction – Individual Features or Clusters Forming a Group

4.1.2 Metal Loss Assessment Methodology

The MFL in-line inspection vendors, when analyzing their inspection data, shall utilize the $RStreng_{0.85dl}$ or $RStreng_{Effective\ Area}$ method (refer to Figure 3) to assess all the metal loss features detected by their tool.

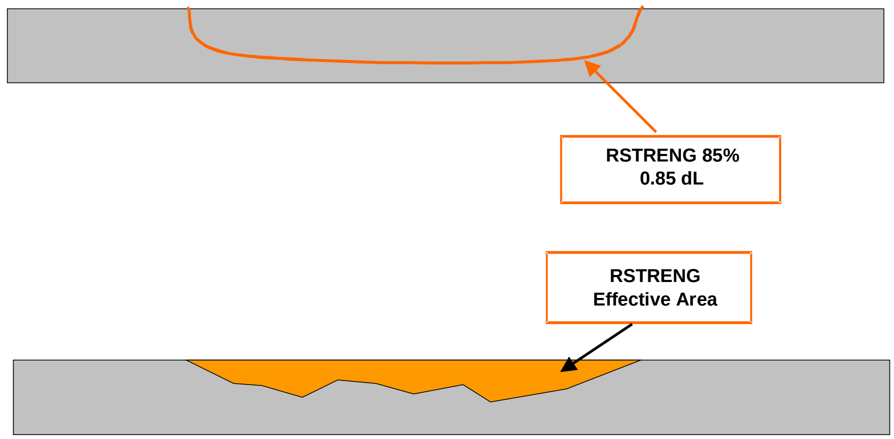


Figure 3 The Different Methodologies for Assessing the Area of Metal Loss

Table 2 shows the acceptable method for calculating burst pressures for the various types of metal loss features (i.e. individual features, clusters, and groups).

Table 2 Acceptable Methods for Calculating Burst Pressures of Metal Loss Features

Metal Loss Feature Type	$RStreng_{0.85dL}$ Method Acceptable?	$RStreng_{Effective\ Area}$ Method Acceptable?
Individual Feature	Yes	Yes
Individual Feature with a Predicted Burst $Pressure_{RStreng\ 0.85dL}$ ≤100% SMYS	No	Yes
Cluster	Yes	Yes
Cluster with a Predicted Burst $Pressure_{RStreng\ 0.85dL}$ ≤100% SMYS	No	Yes
Group	No	Yes

Provided below are the various equations that shall be used for calculating the Predicted Burst Pressure (P) and the Rupture Pressure Ratio (RPR), expressed as a function of the pipe's specified minimum yield strength (SMYS) and the pipeline's Maximum Operating

Pressure (MOP), of any metal loss feature analyzed by the in-line inspection vendors or assessed in the field by Pembina personnel or designate.

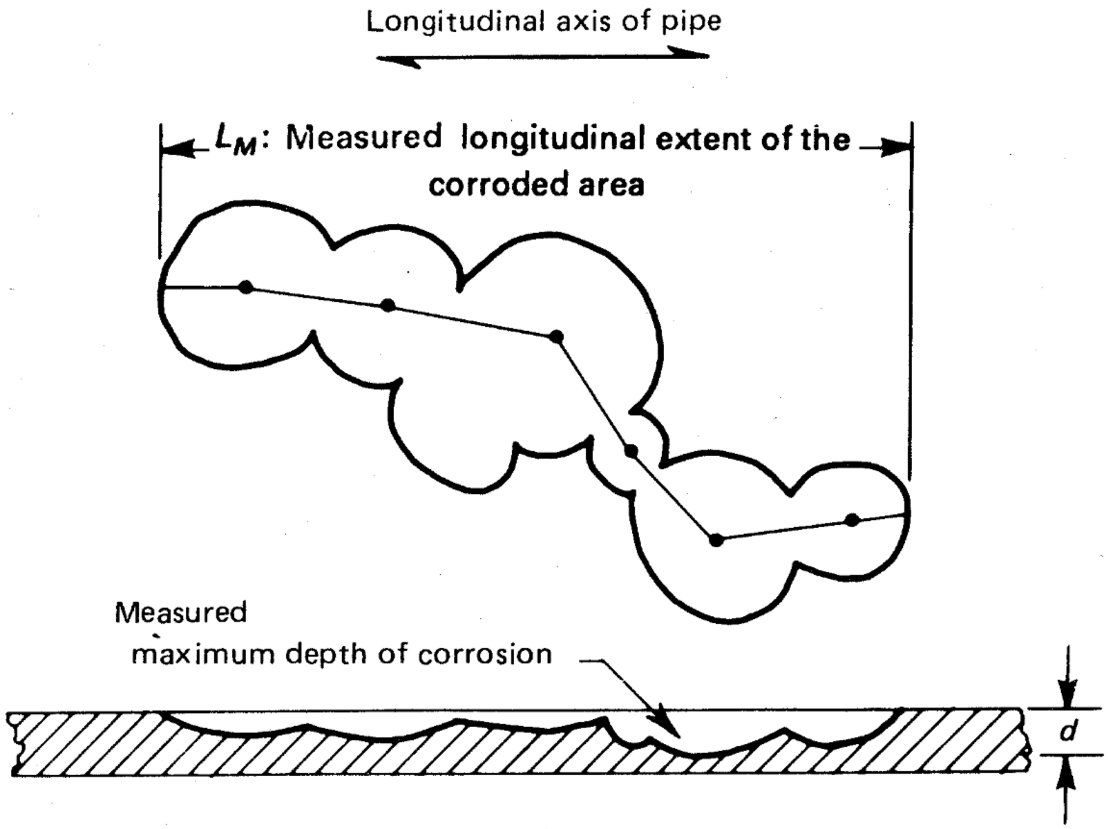


Figure 4 Corrosion Measurements (CSA Z662-2007)

<u>Equation 11a</u>: $\boxed{\text{RStreng}_{\text{0.85dL}}}$ Predicted Burst Pressure

$$\text{Predicted Burst Pressure}_{\text{RSTRENG 0.85dL}} = \frac{2t\,\overline{\sigma}}{D}\left[\frac{1-\dfrac{0.85dL}{A_0}}{1-(\dfrac{0.85dL}{A_0}M^{-1})}\right] \qquad (11a)$$

<u>Equation 11b</u>: $\boxed{\text{RStreng}_{\text{Effective Area}}}$ Predicted Burst Pressure

$$\text{Predicted Burst Pressure}_{\text{EFFECTIVE\_AREA}} = \frac{2t\,\overline{\sigma}}{D}\left[\frac{1-\dfrac{A}{A_0}}{1-(\dfrac{A}{A_0}M^{-1})}\right] \qquad (11b)$$

Where A / A_0 and L are determined through an iterative effective area analysis

<u>Equation 12a</u>: $\boxed{\textbf{RStreng}_{\textbf{0.85dL}}}$ **(RPR based on 100% SMYS)**

$$RPR_{0.85dL} = \frac{\text{Predicted Burst Pressure}_{\text{RSTRENG 0.85dL}}}{\text{Pressure Equivalent to 100\% SMYS}} \quad (12a)$$

<u>Equation 12b</u>: $\boxed{\textbf{RStreng}_{\textbf{Effective Area}}}$ **(RPR based on 100% SMYS)**

$$RPR_{EFFECTIVE\_AREA} = \frac{\text{Predicted Burst Pressure}_{\text{EFFECTIVE\_AREA}}}{\text{Pressure Equivalent to 100\% SMYS}} \quad (12b)$$

<u>Equation 13a</u>: $\boxed{\textbf{RStreng}_{\textbf{0.85dL}}}$ **(RPR based on MOP)**

$$RPR_{0.85dL} = \frac{\text{Predicted Burst Pressure}_{\text{RSTRENG 0.85dL}}}{\text{MOP}} \quad (13a)$$

<u>Equation 13b</u>: $\boxed{\textbf{RStreng}_{\textbf{Effective Area}}}$ **(RPR based on MOP)**

$$RPR_{EFFECTIVE\_AREA} = \frac{\text{Predicted Burst Pressure}_{\text{EFFECTIVE\_AREA}}}{\text{MOP}} \quad (13b)$$

Where:

SMYS	Specified Minimum Yield Strength, kPa
MOP	Maximum Operating Pressure
$\bar{\sigma}$	Flow Stress = SMYS + 68,948 kPa
d	Metal loss maximum depth
L	Metal loss length
A	Predicted area of missing metal
A_0	Original area (L times t)
M	Folias factor
t	Wall thickness
D	Outside diameter

The Folias factor (M) mentioned in the above formulas can be calculated as follows:

$$\text{For } \frac{L^2}{Dt} > 50,\ M = 0.032 \frac{L^2}{Dt} + 3.3 \quad (14a)$$

$$\text{For } \frac{L^2}{Dt} \leq 50,\ M = \sqrt{1 + 0.6275 \frac{L^2}{Dt} - 0.003375 \left(\frac{L^2}{Dt}\right)^2} \quad (14b)$$

4.1.3 Metal Loss Feature Compliance Assessment

When the ILI inspection report is received from the vendor, it shall be aligned with any deformation and cracking ILI data and previous excavation/repair data.

Consideration shall be given to the sizing accuracy of the tool; for example, conventional MFL tools have a wider sizing accuracy for small diameter pitting and axially oriented corrosion and may under-call the depths of these types of corrosion. The vendor specifications should be reviewed and, if possible, field tool correlations to recoated/repaired defects used to adjust the tool sizing before continuing with the compliance assessment.

Although CSA Z662-2007 does not state a timeline for excavating features which fail their acceptance criteria, criteria for immediate excavation and excavation as soon as reasonably practical after receiving the ILI data have been developed as follows:

4.1.3.1 Features Requiring Immediate Excavation

The following features should be excavated immediately by Pembina on receiving and reviewing the ILI data from the Vendor:

- Metal loss features having a depth ≥70% of the pipe's nominal wall thickness, and
- Metal loss features having a predicted burst pressure ≤110% MOP

4.1.3.2 Features Requiring Excavation ASARP

In addition to the features above, the following should be excavated as soon as reasonably practical after receiving the ILI data:

- Preferential seam weld corrosion reported by either metal loss or crack detection tools should be assessed as a crack defect (Section 4.3),
- Metal loss features with a predicted burst pressure less than that stated in Table 3 for the appropriate product and Class Location, and

Table 3 Metal Loss Predicted Burst Pressure Compliance

Product	Class Location	Typical Design Pressure (%SMYS)	Minimum Predicted Burst Pressure (%MOP)
LVP	All	80%	125%
HVP or CO_2	1	80%	
Gas	1 or 2	80% or 72%	
Gas	3 or 4	56% or 44%	140%
HVP or CO_2	2, 3, or 4	64%	150%

Source: CSA Z662-2007 Table 8.1

- For those lines known to be susceptible to internal corrosion, at the discretion of the integrity specialist additional criteria may be adopted which may take into consideration whether the features will grow to a depth of 80% of the nominal pipe wall thickness within three years. Provided below is a table illustrating the starting depths that would reach a depth of 80% nominal pipe wall thickness assuming a variety of wall thicknesses and internal corrosion growth rates. Corrosion growth rates to be used for this assessment can be based on multiple in-line inspection runs, corrosion coupon data, or other available sources. Any additional criteria developed shall be reviewed with the supervisor of Pipeline Integrity.

Table 4 Starting Depth for a Feature to Reach 80% within 3 Years

Pipe Wall Thickness (mm)	Growth Rate (mm/year)		
	0.1	0.15	0.25
3	70%	65%	55%
4	73%	69%	61%
5	74%	71%	65%
6	75%	73%	68%
7	76%	74%	69%
8	76%	74%	71%

- Any other anomaly that in the opinion of the ILI specialist that requires remediation.

The timing associated with excavating the ASARP features shall be determined by Pembina's ILI specialist, taking into account the severity of the features, the "at-site" operating pressure of the pipeline, and/or their estimated time to failure based on a realistic corrosion growth rate. Such features must be excavated within 18 months of receiving the

ILI vendor's final report. If additional time is required to excavate these features, a management of change document (MOC) shall be written.

A flowchart describing the compliance assessment process is shown in Figure 5.

Minimum Predicted Burst Pressure (PBP)
for Class Location and Product

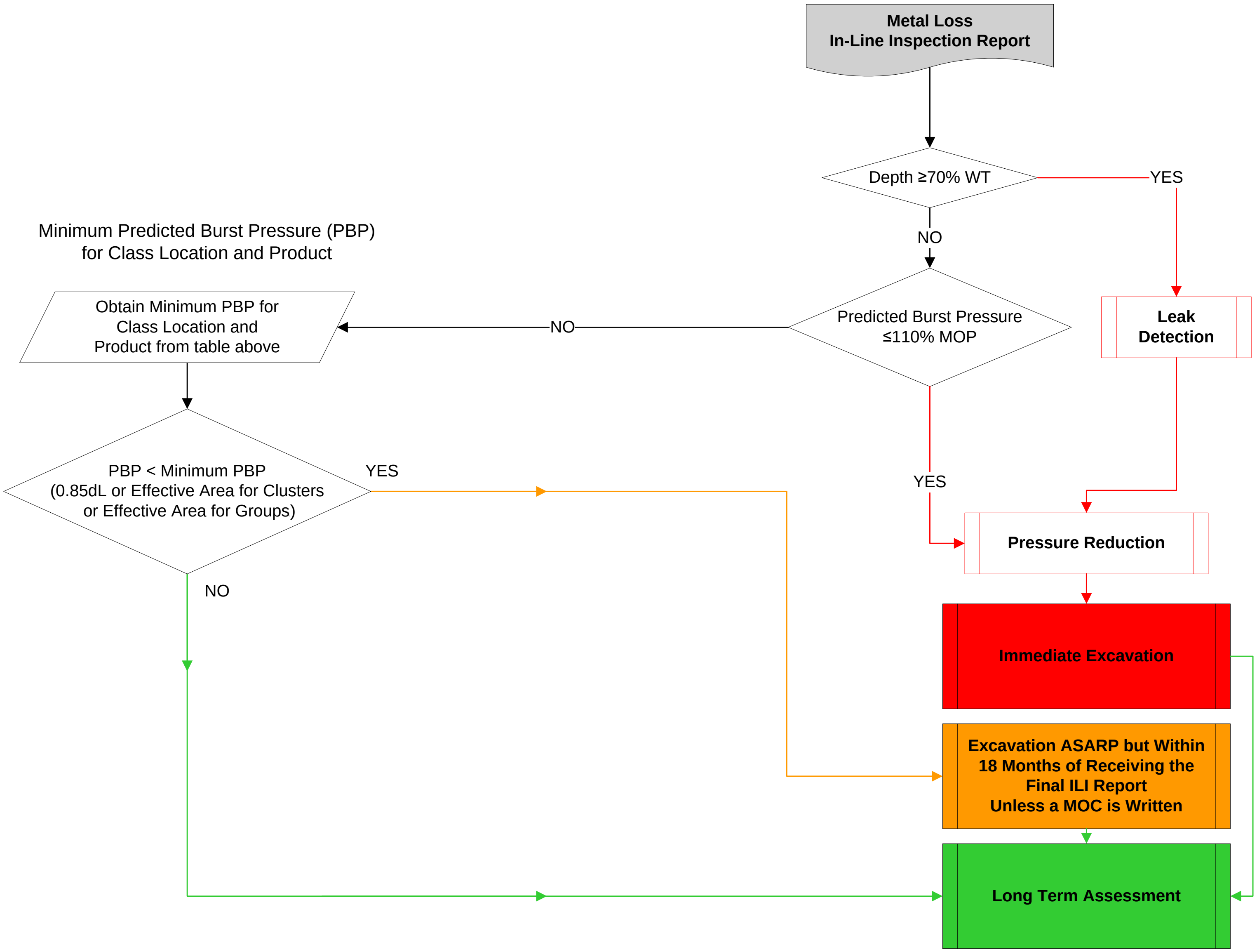


Figure 5 Metal Loss Compliance Assessment Process

4.2 Deformation In-Line Inspection Assessment

4.2.1 Feature Classification for Deformation Features

The purpose of this section is to specify an engineering based approach for assessing the short-term acceptability of features detected by deformation in-line inspection tools.

The deformation in-line inspection vendor, when analyzing their inspection data, shall use the following feature classification for deformation features:

1. **Dent**: Is an inward distortion of the pipe wall resulting in a change of the internal diameter but not necessarily resulting in a localized reduction of wall thickness (Refer to Figure 6).

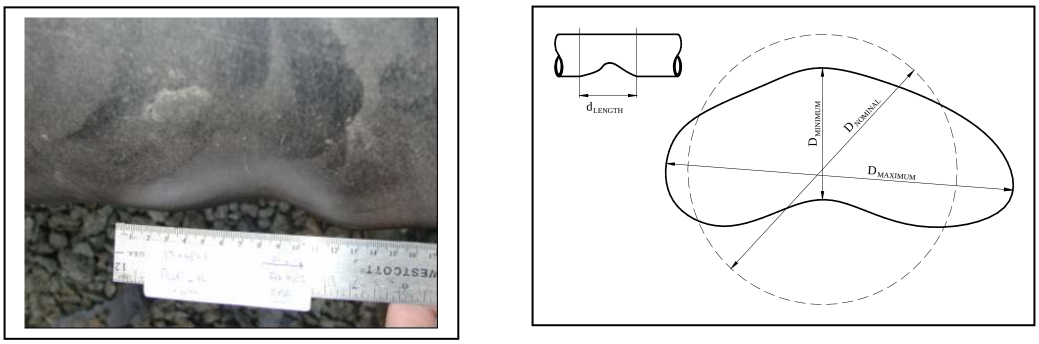


Figure 6 Illustration of Dents

2. **Wrinkle**: Is a transverse surface irregularity normally found in the crotch of a pipe bend or in association with wall thickness transitions and/or locations of ovality (Refer to Figure 7).

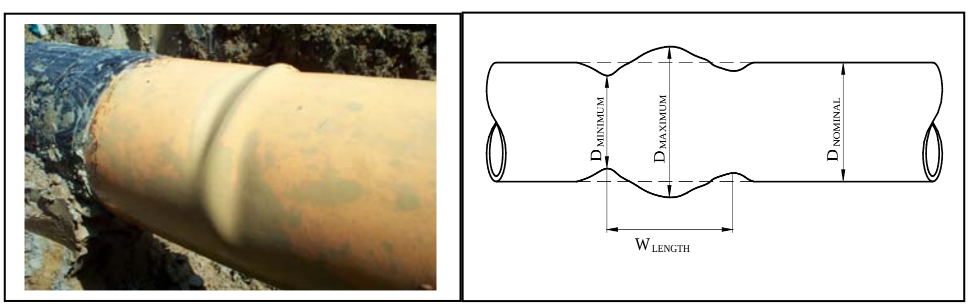


Figure 7 Illustrations of Wrinkles

3. **Ovality**: Is an area in which the pipe is out of round (i.e. egg shaped or broadly elliptical) (refer to Figure 8).

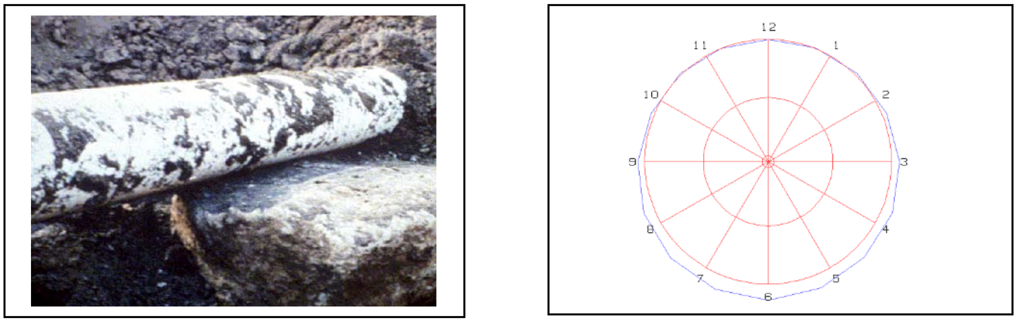


Figure 8 Illustrations of Ovality

4.2.2 Deformation Assessment Methodology

The deformation in-line inspection vendors, when analyzing their inspection data, shall utilize the following formulas to assess the deformation features detected by their tool.

4.2.2.1 Dents

All dents identified by the deformation in-line inspection vendor shall be analyzed using the criteria described in Figure 9:

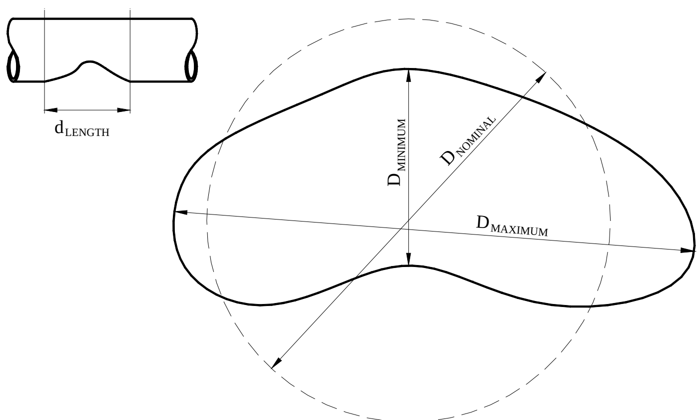


Figure 9 Dent Measurement

Dent Depth (d) (mm) $= D_{NOMINAL} - D_{MINIMUM} - \left(\frac{D_{MAXIMUM} - D_{NOMINAL}}{2} \right)$ (1)

Dent Depth (Percentage) $= \frac{d \times 100\%}{D_{NOMINAL}}$ (2)

% Diameter Restriction $= \frac{D_{NOMINAL} - D_{MINIMUM}}{D_{NOMINAL}} \times 100\%$ (3)

4.2.2.2 Wrinkles

All wrinkles or bulges identified by the deformation in-line inspection vendor shall be analyzed using the following criteria:

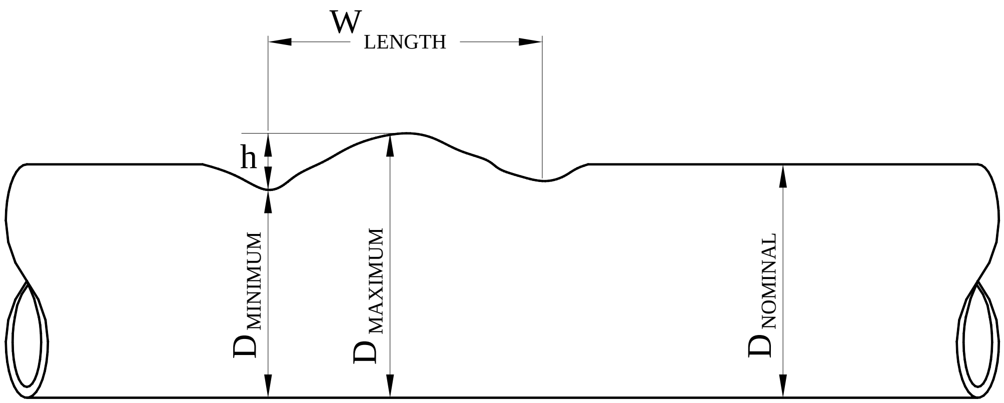


Figure 10 Wrinkle Measurement

$$\text{Wrinkle Size (h) (mm)} = D_{MAXIMUM} - D_{MINIMUM} \tag{4}$$

$$\text{Wrinkle Size (Percentage)} = \frac{\text{Wrinkle Size (h)} \times 100\%}{D_{NOMINAL}} \tag{5}$$

$$\text{\% Diameter Restriction} = \frac{D_{NOMINAL} - D_{MINIMUM} \times 100\%}{D_{NOMINAL}} \tag{6}$$

$$\text{Wave Length to Height Ratio} = \frac{\text{Length } (W_{Length})}{\text{Wrinkle Size (h)}} \tag{7}$$

$$\text{Circumferential Extent} = \frac{\text{Circumferential Extent of Wrinkle} \times 360°}{\text{Circumference of Pipe}} \tag{8}$$

$$\text{Height Ratio} = \frac{\text{Wrinkle Size (h)}}{\text{Pipe Wall Thickness}} \tag{9}$$

4.2.2.3 Ovality

All areas of ovality identified by the deformation in-line inspection vendor shall be analyzed using the following criteria:

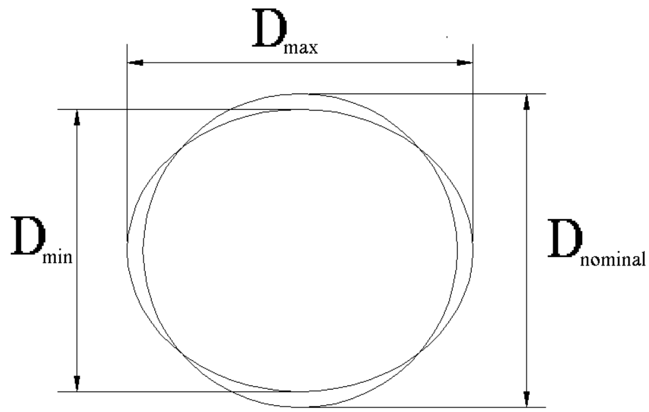


Figure 11 Ovality Measurement

$$\text{Ovality Size (Percentage)} = \frac{D_{MAXIMUM} - D_{MINIMUM}}{(D_{MAXIMUM} + D_{MINIMUM})*0.5} \times 100\% \qquad (10)$$

4.2.3 Deformation Feature Compliance Assessment

When the ILI inspection report is received from the vendor, it shall be aligned with any metal loss and cracking ILI data and previous excavation/repair data. Although CSA Z662-2007 does not state a timeline for excavating features which fail their criteria, criteria for immediate excavation and excavation as soon as reasonably practical after receiving the ILI data has been developed as follows:

4.2.3.1 Features Requiring Immediate Excavation

In Section 10.9.4.2 of CSA-Z662-2007, Note 2 states that consideration for investigating topside dents (defined as a circumferential position between 8:00 and 4:00 for the purposes of this document) should be given because of the probability that they are caused by excavating equipment. As such, any

- Topside dent with an indication of metal loss, cracking or other stress riser, or
- Topside dent with a depth of 6 mm or larger in a pipe 101.6 mm OD or smaller or 6% or larger of the outside diameter in pipe larger than 101.6 mm OD

should be excavated immediately by Pembina on receiving and reviewing the ILI report from the vendor.

4.2.3.2 Features Requiring Excavation ASARP

In addition to the features described above, the following should be excavated as soon as practical after receiving the ILI data:

- Bottomside dents that contain stress concentrators (metal loss, gouges, grooves, arc burns or cracks);
- Wrinkles, bulges, or ripples that contain gouges, grooves, arc burns, or cracks;
- Bottomside dents that are located on the pipe body and exceed a depth of 6 mm in a pipe 101.6 mm OD or smaller or 6% of the outside diameter in pipe larger than 101.6 mm OD;
- Dents that are located on a mill or field weld and exceed a depth of 6 mm in pipe 323.9 mm OD or smaller or 2% of the outside diameter in pipe larger than 323.9 mm OD;

In addition to the CSA Z662-2007 requirements listed above, Pembina shall also address deformation features that meet the following additional criteria, based on industry best practices, for wrinkles, bulges, and ovality:

- Wrinkle or bulge with a height (measured from peak to valley) of >150% of the pipe nominal wall thickness, a wavelength to height ratio ≤12, a circumferential extent ≥120° of the pipe's circumference, a height (measured from peak to valley) as calculated in Table 5, or a stress concentrator.

Table 5 Maximum Allowable Wrinkle Size Based on Actual Hoop Stress

Hoop Stress, S (Psi)	Maximum Allowable Depth (% of OD)
≤20,000 Psi	2
>20,000 Psi but ≤30,000 Psi	$\left(\frac{30{,}000 - S}{10{,}000} + 1\right)$
>30,000 Psi but ≤47,000 Psi	$0.5\left(\frac{47{,}000 - S}{17{,}000} + 1\right)$
>47,000 Psi	0.5

Source: CEPA Procedure for Developing a Preliminary Assessment of Kinks

Where S is the hoop stress level at the feature location.

- Ovality of the pipeline >6% of the pipeline diameter.
- Any other anomaly that in the opinion of the ILI specialist that requires remediation. For example, multiple topside dents or topside dents not previously detected which do not meet any of the above criteria but may be indicative of recent mechanical damage.

The timing associated with excavating the ASARP features shall be determined by Pembina's ILI specialist taking into account the severity of the features and/or their estimated time to failure based on a fatigue analysis. Such features must be excavated within 18 months of receiving the ILI vendor's final report. If additional time is required to excavate these features, a management of change document (MOC) shall be written.

The following assumptions shall be made when assessing any deformation feature:

- In order for dents to be considered as having associated metal loss, cracking, or other stress risers, the metal loss, cracking or other stress risers must be within ±30 cm of the dent.

- In order for dents to be considered as being located on a girth or seam weld the dents must be within ±30 cm of a girth weld or ±5 cm of a longitudinal seam weld.

A flowchart describing the compliance assessment process is shown in Figure 12.

Any other deformation features not covered by the above criteria should be assessed by a qualified individual to determine if a threat to the pipeline's integrity exists.

Hoop Stress, S (Psi)	Maximum Allowable Depth (% of OD)
≤20,000 Psi	2
>20,000 Psi but ≤30,000 Psi	$\left(\frac{30{,}000 - S}{10{,}000} + 1\right)$
>30,000 Psi but ≤47,000 Psi	$0.5\left(\frac{47{,}000 - S}{17{,}000} + 1\right)$
>47,000 Psi	0.5

Maximum Allowable Depth based on Hoop Stress

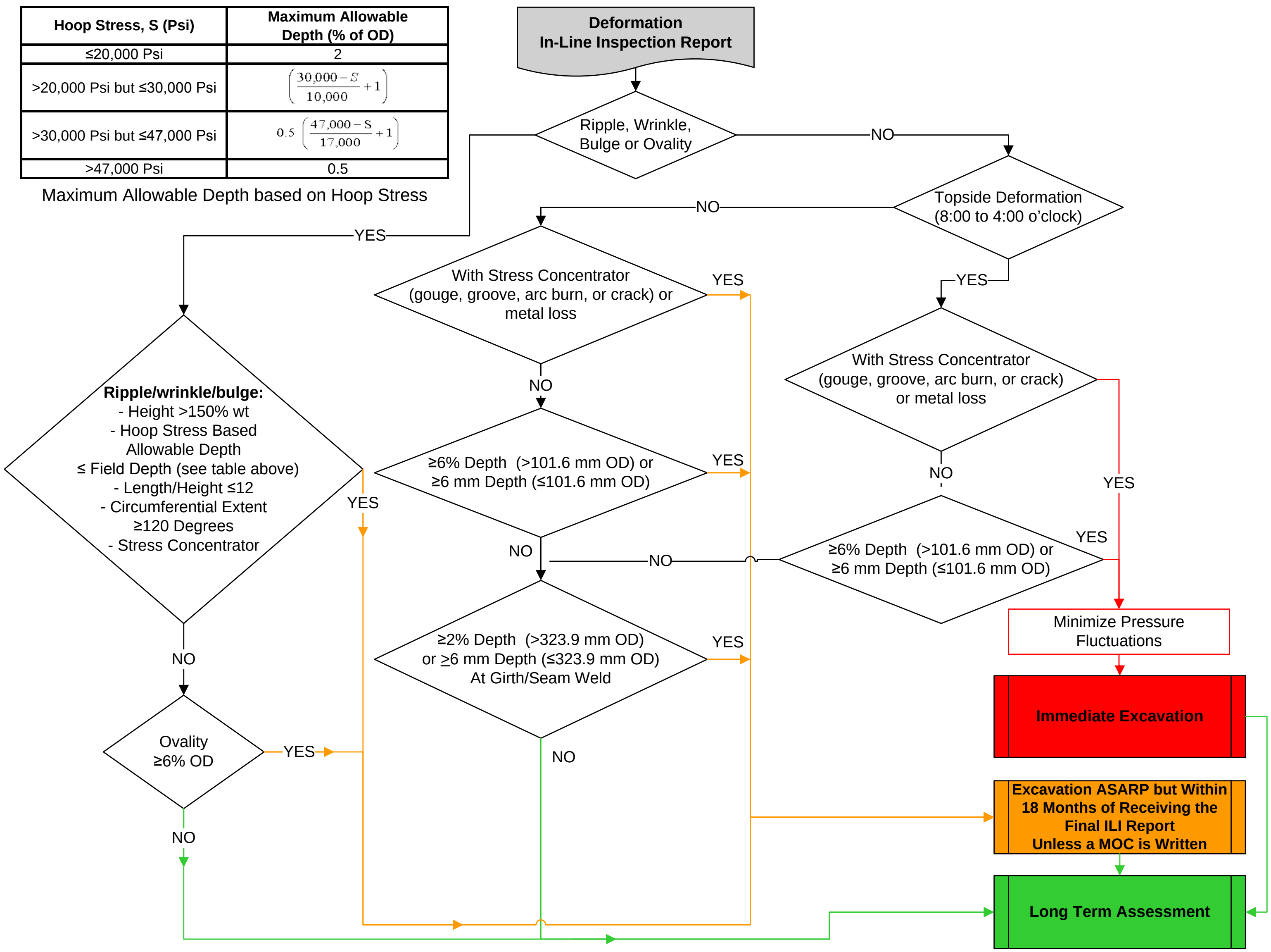


Figure 12 Deformation Compliance Assessment Process

4.3 Crack Assessment

The purpose of this section is to specify an engineering based approach for assessing the short-term acceptability of features detected by crack detection ILI tools.

4.3.1 Crack Interaction Criteria

Once the individual features have been reported by the vendor those individual features shall be assessed to determine whether they interact with any adjacent features detected by the tool. Only features reported with length and depth shall be included when applying the feature interaction criteria discussed below.

- The features should be interacted using a ±10 cm criteria as shown:

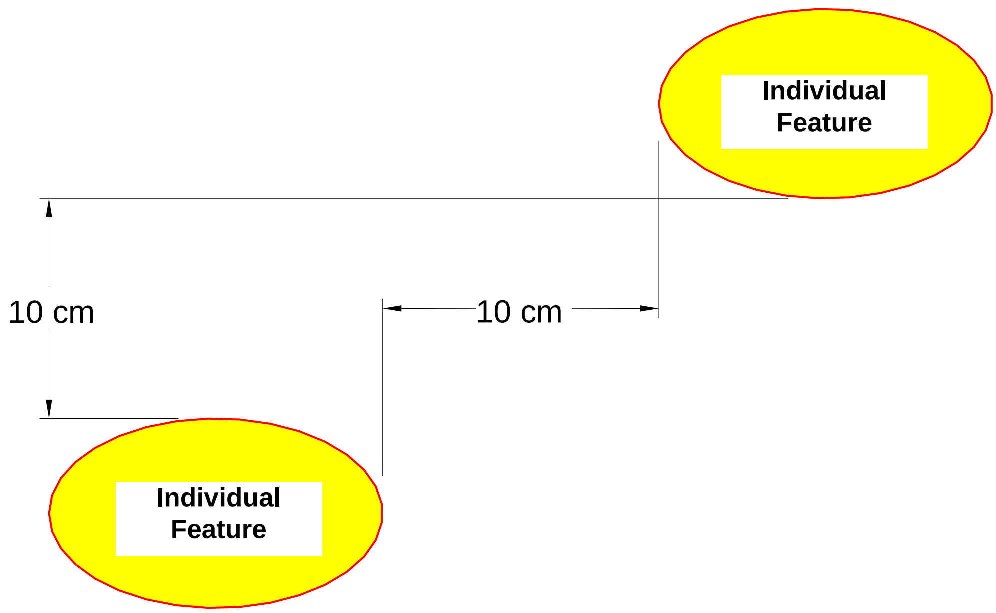


Figure 13 Example of a Graphical Depiction of the Interaction Criteria for Features Identified by a Crack Detection Tool

Provided in Figure 14, Figure 15, and Figure 16 are examples of individual features that were determined to interact based upon the aforementioned criteria. The predicted burst pressures of the interacted features shall be calculated based upon the overall dimensions of the interacted features as represented by the "shaded" areas in the figures.

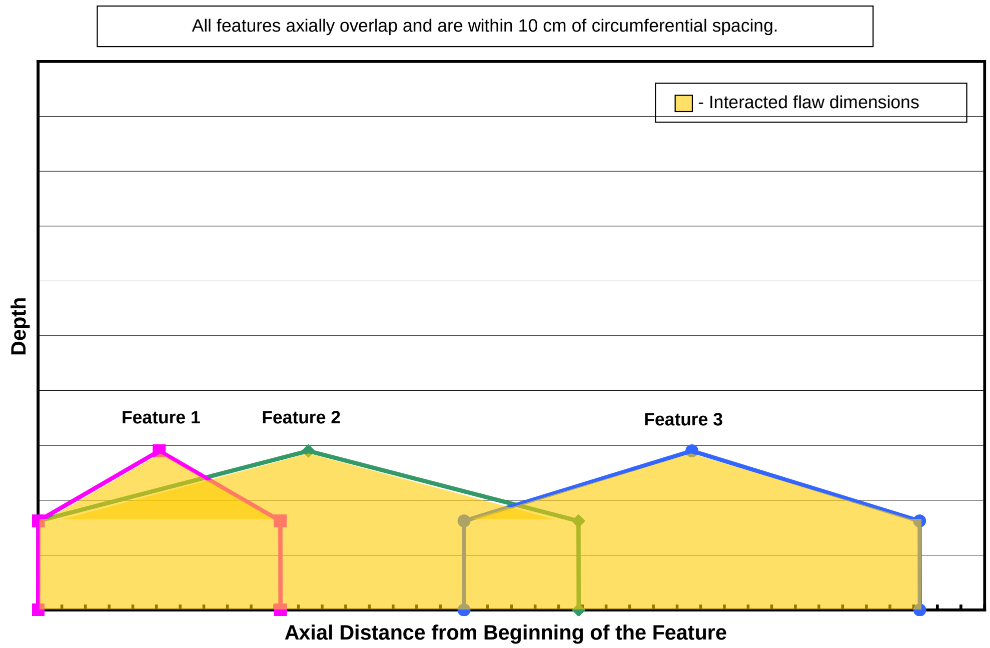


Figure 14 Example #1 of a Graphical Depiction of the Interaction Criteria for Features Identified by a Crack Detection Tool

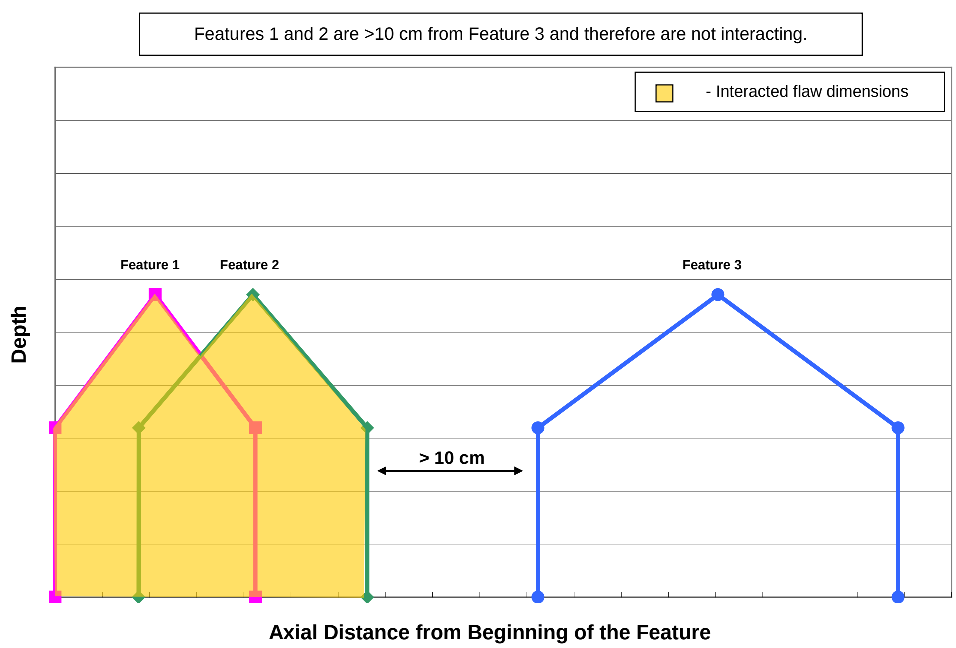


Figure 15 Example #2 of a Graphical Depiction of the Interaction Criteria for Features Identified by a Crack Detection Tool

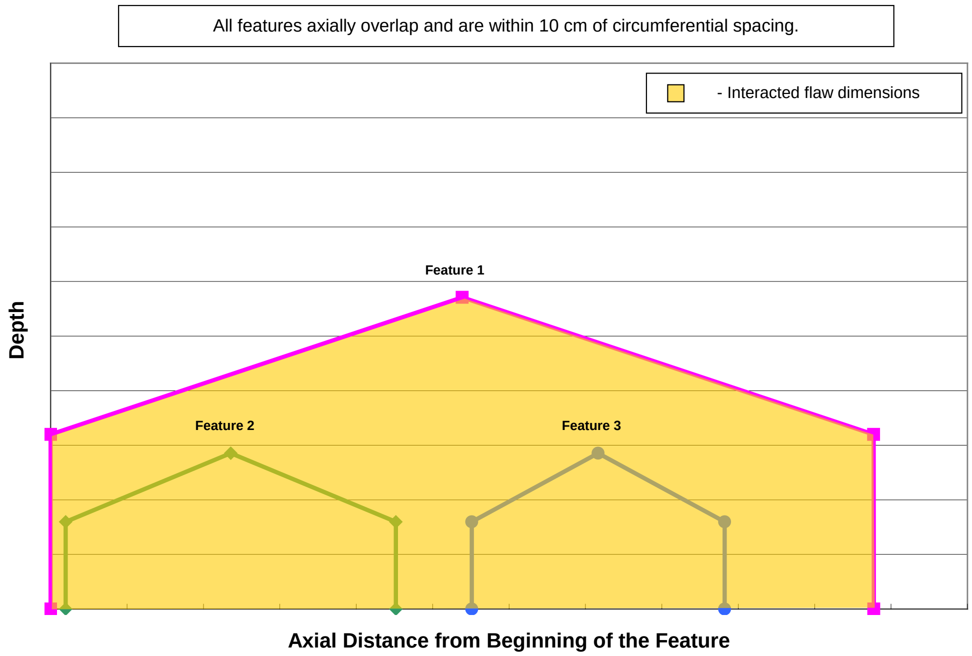


Figure 16 Example #3 of a Graphical Depiction of the Interaction Criteria for Features Identified by a Crack Detection Tool

4.3.2 Crack Feature Assessment Methodology

The predicted burst pressures of the individual features in the pipe body shall be calculated using CorLAS™ or KAPA, where possible, using both nominal/minimum and average mechanical properties for the pipe body in the given pipeline. Similarly, for individual features in the longitudinal seam weld, nominal/minimum and average mechanical properties for the seam weld shall be used when calculating the predicted burst pressures of the individual features using CorLAS™ or KAPA.

Interacted features should have their burst pressure calculated using a simplified flaw profile input into CorLAS™, which will determine the burst pressure of the interacted features. If this burst pressure is lower than that of the individual features, it shall be used for each of the features. If not, the individual feature burst pressures shall be used.

Using nominal/minimum mechanical properties will provide the most conservative estimations with respect to predicted burst pressure. By comparison, using average mechanical properties will provide a more realistic estimation with respect to predicted burst pressure, especially if documentation (i.e. Mill Test Certificates and/or mechanical testing of selected pipe samples) indicates that the actual mechanical properties are substantially higher than the nominal/minimum mechanical properties.

4.3.3 Crack Feature Compliance Assessment

When the ILI inspection report is received from the vendor, it shall be aligned with any deformation and metal loss ILI data and previous excavation/repair data.

Consideration shall be given to the sizing accuracy of the tool since ultrasonic crack detection inspection is a relatively new technology. If possible, field tool correlations to recoated/repaired defects should be used to adjust the tool sizing before continuing with the compliance assessment.

Although CSA Z662-2007 does not state specific acceptance criteria for assessing crack detection in-line inspection data, criteria for immediate excavation and excavation as soon as reasonably practical have been developed as follows. Preferential seam weld corrosion reported by either metal loss or crack detection tools should be assessed as a crack defect.

4.3.3.1 Features Requiring Immediate Excavation

The following features should be excavated immediately by Pembina on receiving and reviewing the ILI report from the Vendor:

- Crack-field, crack-like, notch-like, and weld anomaly features with a predicted depth greater than the maximum reporting depth bin of the tool, regardless of length,
- Crack-field and crack-like features located in a dent as well as those notch-like and weld anomaly features with reported depths located in a dent,
- Gouge, groove or seam weld corrosion with a predicted depth greater than the maximum reporting depth bin of the tool, regardless of length.
- Crack-field, crack-like, notch-like, weld anomaly, and seam weld corrosion features having a predicted burst pressure ≤110% MOP, and
- Any other anomaly that in the opinion of the ILI specialist that requires remediation.

4.3.3.2 Features Requiring Remediation ASARP

In addition to the features above, the following should be excavated as soon as reasonably practical after receiving the ILI data:

- Crack-field, crack-like, notch-like, and weld anomaly features with a predicted burst pressure less than that stated in Table 6 for the appropriate product and Class Location,

Table 6 Crack-Field, Crack-Like, Notch-Like, and Weld Anomaly Feature Predicted Burst Pressure Compliance

<table>
<tr><th>Product</th><th>Class Location</th><th>Typical Design Pressure (%SMYS)</th><th>Minimum Predicted Burst Pressure (%MOP)</th></tr>
<tr><td>LVP</td><td>All</td><td>80%</td><td rowspan="3">125%</td></tr>
<tr><td>HVP or CO_2</td><td>1</td><td>80%</td></tr>
<tr><td>Gas</td><td>1 or 2</td><td>80% or 72%</td></tr>
<tr><td>Gas</td><td>3 or 4</td><td>56% or 44%</td><td>140%</td></tr>
<tr><td>HVP or CO_2</td><td>2, 3, or 4</td><td>64%</td><td>150%</td></tr>
<tr><td>Sour</td><td>All</td><td>40% - 72%</td><td>100% SMYS</td></tr>
</table>

Note: The length of the crack-field, crack-like, notch-like, and weld anomaly feature(s) to be used in the critical flaw size calculations shall be both the "maximum interlinked crack length" reported by the in-line inspection vendor, if provided, and the total length of the crack-field, crack-like, notch-like, or weld anomaly feature. These two lengths will result in the upper and lower bound values of predicted burst pressure. The values to actually use for the compliance assessment will be governed by the confidence in the vendor's reported "maximum interlinked crack length".

- Corrosion metal loss features containing cracks. Such details would only be obtained by overlaying metal loss and crack detection in-line inspection data.

- Laminations which run into either the longitudinal weld seam or girth weld.

The timing associated with excavating the ASARP features shall be determined by Pembina's ILI specialist, taking into account the severity of the features, the "at-site" operating pressure of the pipeline, and/or their estimated time to failure based on a realistic growth rate for cracks or corrosion, or fatigue for other crack related defects, as applicable. Such features must be excavated within 18 months of receiving the ILI vendor's final report. If additional time is required to excavate these features, a management of change document (MOC) shall be written.

A flowchart describing the compliance assessment process is shown in Figure 17.

Product	Class Location	Minimum Predicted Burst Pressure (%MOP)
LVP	All	125%
HVP or CO_2	1	
Gas	1 or 2	
Gas	3 or 4	140%
HVP or CO_2	2, 3, or 4	150%
Sour	All	100% SMYS

Minimum Predicted Burst Pressure (PBP) for Class Location and Product

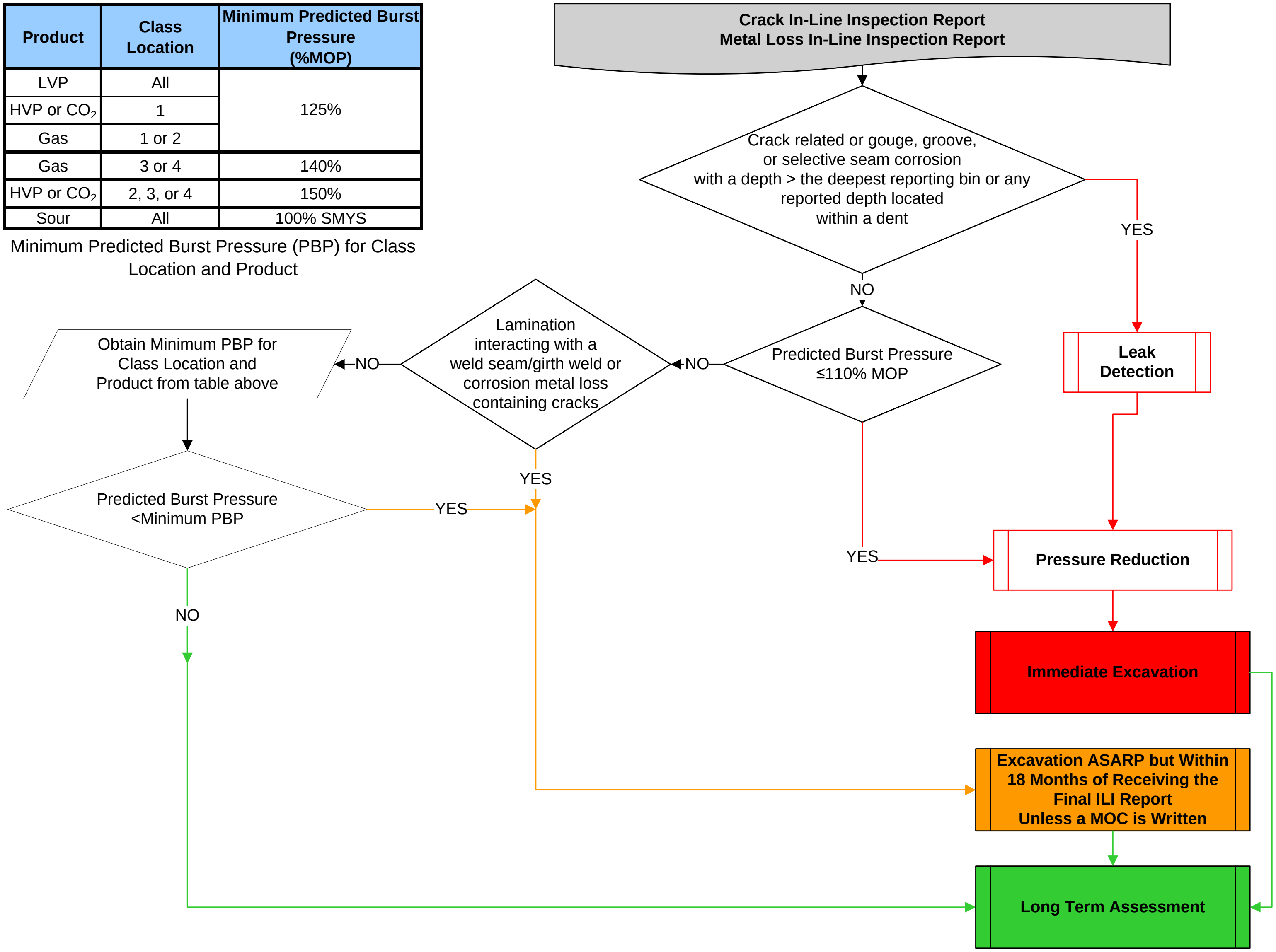


Figure 17 Crack Related Feature Compliance Assessment Process

5.0 Pipeline Excavation/Assessment

5.1 Excavation Location in the Field

The excavation and repair process is initiated by accurately defining the dig location. Dig sites must be accurately measured to avoid excavation at the wrong location and to correctly define the notification and access requirements.

a) Excavation directives ("dig sheets") generated by Pipeline Integrity shall contain information as to the distance from the nearest benchmark to the upstream girth weld of the featured joint.

b) The location of the excavation in the field shall be identified utilizing all available information to ensure an accurate location of the pipeline, and all other facilities located within close proximity of the worksite.

c) Location of an in-line inspection feature shall be determined through slack-chain or GPS-profile from an upstream and/or downstream benchmark. Feature location based on slack-chain process requires that both the benchmark chainage (absolute) and the relative (slack-chain) chainage be reported. Feature location based on GPS-profile process requires the GPS coordinates (differential) of both the benchmark and the associated profile log coordinates.

d) With the location of the excavation established, all efforts must be explored to identify any Pembina and foreign underground facilities situated near the excavation. Sources of information to explore for the location of Pembina and foreign facilities include, but are not limited to the following:

    i. Pembina as-built drawings,

    ii. Legal and township plans, and land titles,

    iii. Survey plans of any nature,

    iv. Regulatory maps,

    v. EGIS™ and Abadata™ databases

    vi. One call services,

    vii. Foreign facility information, and

    viii. Landowner contact information.

e) Once on site Pembina's representative shall:

   i. Review all available information. Any ambiguity to items noted must be reviewed to ensure that the excavation can be conducted safely.

   ii. Ensure all facilities are located and staked. If a facility cannot be located then a review shall be conducted to ensure that the excavation can be conducted safely.

   iii. Ensure that an electronic sweep of the entire worksite has been conducted to locate any other potential facilities that have not been identified by the areas explored above.

f) Should the excavation extend beyond the established excavation site all efforts to identify underground facilities shall be explored in the new extended work site area. The initial search for underground should be extensive to allow for the possibility of an extended excavation site.

5.2 Approvals and Access

Once the dig site has been accurately located, all appropriate approvals for access and excavation must be obtained. These requirements are outlined in Pembina's HSE Standards Manual, Part 4.26 (Trenching & Excavation) and Part 9.07 (Pipeline O&M). If the site is located in an area of higher consequence, Calgary Head Office is to be notified in accordance with Table 7. Higher consequence areas may require additional regulatory approvals and/or specific engineering considerations. Areas of higher consequence include:

- Provincial or Federal Parks
- Indian Reserve
- Transportation corridor (Road or Railway, etc.)
- No crossing agreement in place
- Issues with landowner on compensation
- High population area
- Flood zone area
- Identification of possible contaminated soil
- Waterway or small stream
- Wildlife or Fisheries
- Reseeding required in public lands
- Slope stability or erosion
- Working at the toe (bottom) of a slope
- Known landowner related issues

Table 7 Calgary Office Notification

Type of HCA	Department	Contact
Crossing or Location	Land	Land Services Coordinator
Environmentally Sensitive	HSE & Integrity	Supervisor, HSE Field Services
Protected Habitat	HSE & Integrity	Environmental Specialist
Geotechnical	Engineering	Supervisor, Mechanical Engineering

All notifications are as per HSE 9.07 PIPELINE OPERATIONS and MAINTENANCE, Pipeline Exposure/Repair. Access to pipeline anomaly excavation sites should be limited to the right of way whenever possible. Should access to the ROW require crossing of private or public lands, landowners or the individuals responsible for managing that land must first be contacted, and approval granted. Where formal application processes do not exist and it is practical to do so, a Quick Rite (written approval) should be obtained prior to commencing work. Information on other pipelines can be obtained by contacting First Call. Access to pipeline anomaly inspection sites should be limited to the right of way (ROW) whenever possible. Table 8 and Table 9 summarize areas of responsibility and estimated periods required to gain approval:

Table 8 Access Approvals

Area	Contact	Approval	Approximate Time
Green Lands – Forested (AB)	ASRD – Public Land & Forests Division	Quick Rite or Verbal	1 day
Crown Lands outside of ALR (BC)	OGC	Application Required	14-21 days
Green Lands – Grazing (AB)	Land User	Quick Rite or Verbal	1 day
Crown Land with Grazing Tenure Issued (BC)	OGC, also need Range Tenure Agreement	Application to OGC required. Agreement required with tenure holder.	14-21 days
White Lands – Crown (AB)	AENV, ASRD	Verbal	1 day
Crown Land within Agricultural Land Reserve (ALR) (BC)	OGC and LRC (Land Reserve Commission)	Application required to OGC. Notification to LRC if development under 5km. More than 5km, need application to LRC.	14-21 days
White Lands – Private (AB)	Land Owner	Quick Rite or Verbal	1 day
Private Land within ALR (BC)	Land Owner	Verbal	1 day
Water Crossing – Minor (AB)	AENV, Regional Water Manager	Application	3-4 weeks
Water Crossing – Minor (BC)	OGC and Supervisor, HSE	Section 9 Application required	7-10 days
Water Crossing – Navigable (AB)	Department of Fisheries and Oceans (DFO) and AENV, Navigable Waters	Letter	3-4 months
Water Crossing – Navigable (BC)	DFO, OGC and Supervisor, HSE	Applications required	3-4 months

Table 9 Activity Approvals

Area	Contact	Approval	Approximate Time
Equipment Crossing (AB)	Owner/Operator	Verbal	1 day
Equipment Crossing (BC)	Owner/Operator	Verbal	1 day
Safety (AB)	Area HSE Coordinator	Verbal	2 days
Safety (BC)	OHS	Verbal	2 days
ROW Activity (AB)	Pipeline Control Center	Verbal	Daily
ROW Activity (BC)	OGC	Verbal	2 days
Private Roads (AB)	Land Owner	Verbal	1 day
Private Roads (BC)	Land Owner	Verbal (should be supported by an agreement)	1 day
Excavations (AB)	Alberta One Call	Verbal	3 days
Excavations (BC)	BC One Call	Verbal	3 days

AENV - Alberta Environment
ASRD – Alberta Sustainable Resources Development
OGC - Oil and Gas Commission
ALR – Agricultural Land Reserve

5.3 Excavation

5.3.1 Pipe-to-Soil Potentials and Soil Resistivity

Pembina shall consider on a pipeline by pipeline basis whether to conduct any or all of the following measurements:

a) Following the location of all underground facilities within the work site and the location and staking of all underground facilities within 30 meters of the excavation site, an interrupted close interval pipe-to-soil potential (CIS) survey should be considered when and where possible (i.e. when the test posts are readily accessible) over the excavation site and for 30 meters beyond each side of the staked work site to be excavated. Reference points shall be established such that any corrosion found on the pipe surface can be located accurately on the CIS profile.

b) Pipe-to-soil potentials should also be considered at the closest test stations or pipeline appurtenances, to compare with the annual survey data.

c) Soil resistivity measurements should be considered, when and where possible, at the location of the corrosion feature(s) being excavated using the “four pin method”. Four different readings with the pins should be spaced at distances of 2.5, 5, 10, and 15 feet to obtain “apparent” soil resistivity measurements at corresponding depths.

5.3.2 Pressure Reduction for Excavation and Assessment

Prior to commencement of any excavations:

i. Temporary pressure restrictions, if required, shall be implemented on the pipeline section.

ii. If the defect as identified through the in-line inspection exceeds any of the criteria identified in Sections 4.1.3, 4.2.3, or 4.3.3, then a temporary pressure reduction is required during the excavation and assessment period.

iii. The temporary pressure restriction on the pipeline section during the excavation, and assessment process shall be determined as follows:

   - For features where a remaining strength can be calculated;. The "at-site" pressure of the pipeline can be used if a reliable pressure profile is available for the system; otherwise the maximum operating pressure of the pipeline shall be used.

     - For features with a depth ≥70% wall thickness but a burst pressure >125% of the "at-site" MOP a 20% reduction of the highest maximum operating pressure recorded in the last 60 days.

     - For features with a depth <70% wall thickness and a burst pressure ≤125% of the "at-site" MOP the applicable pressure should be less than the Predicted Burst Pressure/1.25 for Class 1 or Predicted Burst Pressure/1.5 for Class 2, 3 and 4 locations.

   - For features where a remaining strength can not be calculated:

     - 20% reduction of the highest maximum operating pressure recorded in the last 60 days.

     Note: Should a pressure restriction already be imposed on the system, Pembina will consider whether further restrictions are required.

iv. Normal operating pressures may be resumed once the assessment is completed, if the anomaly is found to be within the specified limits, or has been repaired.

5.3.3 Typical Excavation

A typical excavation to locate an in-line inspection feature is illustrated in Figure 18.

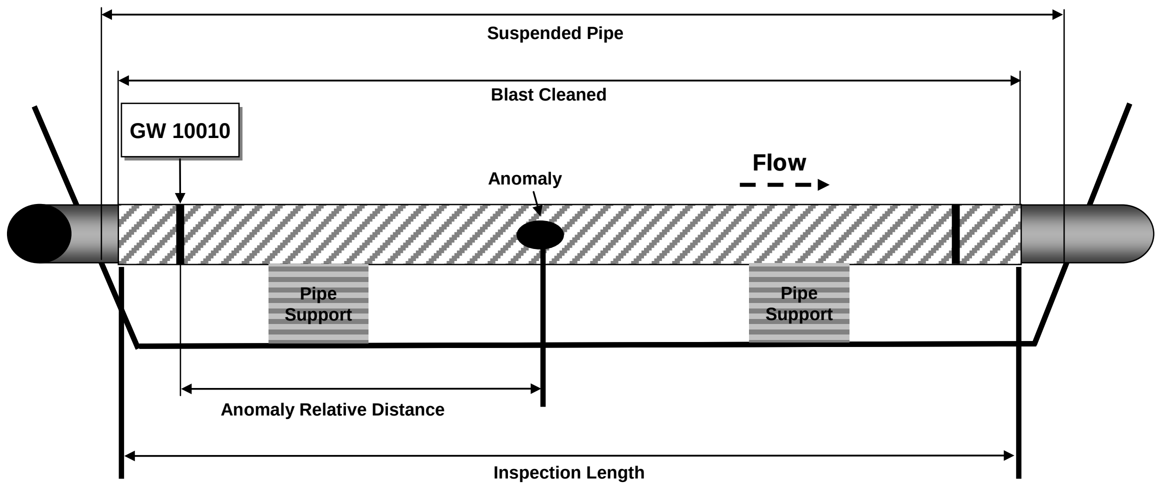


Figure 18 Example of a Typical Excavation

5.3.4 Conducting an Excavation

All excavations and entry into an excavation are to done in accordance with Pembina HSE 4.03 CONFINED SPACE ENTRY, HSE 4.26 GROUND DISTURBANCE and HSE 9.07 PIPELINE OPERATIONS and MAINTENANCE, Pipeline Exposure/Repair.

For isolated anomalies, only the anomaly of interest needs to be excavated. If multiple anomalies are reported within a reasonable distance or extensive corrosion or stress corrosion cracking is found during inspection, consideration should be given to extending the excavation length. Document any unique features of the excavation area.

5.3.5 Minimum Required Equipment by an NDT Contractor

The NDT contractor shall have on site, as a minimum, the following equipment or equivalent:

- Measuring tapes, magnets, and markers
- Portable copper-copper/sulphate reference electrode or equivalent
- Multimeter
- Soil Resistance Meter and soil pins
- Litmus paper (graduations of 0.5)
- Digital camera (minimum six mega pixel images with macro capability)

- Ultrasonic flaw detector with pencil probe for corrosion mapping
- Pit gauge and corrosion bridging bar (if pit gauge is used for mapping corrosion)
- Corrosion grid (12.7 mm x 12.7 mm) either magnetic sheet or wire grid
- Ultrasonic wall thickness meter
- Dent profile gauge(s)
- Ovality caliper tool
- 5% nital solution (etchant for identifying the complete removal of hard spots, arc burns and gouges, see Appendix D)
- AC magnetic yoke
- White contrast paint
- Black magnetic particle bath (water based)
- Angle grinder with 80 to 120 grit flap disk or abrasive wheel (hard backed discs may be required for longseam removal)

Where applicable, all equipment should be calibrated as per the manufacturer's instructions and/or any industry standards.

5.3.6 Description of Terrain Conditions

The land use, access method to the site, nearby transportation routes, soil and terrain conditions (i.e. topography, soil type and drainage), and ditch dimensions associated with each excavation site shall be identified and recorded on Forms 1 and 2 "Ditch Profile Report" and "General Excavation Report" (refer to Appendix J for the forms). Descriptions of the various topography, soil types and drainage that can be encountered during an excavation are detailed in Appendix E.

Digital photos shall be taken of:

- The view upstream from each end of the excavation,
- The view downstream from each end of the excavation,
- Views from each side of the excavation,
- The entire soil profile with a size reference (i.e. a shovel), and
- Close up photographs of each soil type with a size reference (i.e. a pencil)

5.3.7 Description of Coating Type and Condition

The type of coating observed on the pipeline shall be recorded on Form 2 "General Excavation Report". Observations shall detail the mainline coating system and other coatings apparent on the carrier pipe within the extent of the excavation. A qualitative assessment of coating condition shall be undertaken utilizing the information in Appendix F and results of the coating assessment shall be recorded on Form 2. A measurement of all coating holidays or areas of disbondment shall be completed using Form 3 “Coating Data Sheet” (refer to Appendix J for the forms).

Digital photos shall be taken to depict the condition of the coating at each excavation site. These areas should include:

- An overview of each side of the exposed pipe and the top and bottom of the pipe,
- Close up photographs of typical disbondments and holidays, and
- Close up photographs of ILI anomaly areas (with the anomaly location marked on the coating)

Prior to removal and selection of a cleaning method, the type of coating on the pipe must be considered. Caution must be exercised when working with coal tar coatings as they may contain asbestos. All coating containing asbestos is to be removed in accordance to HSE 4.02, ASBESTOS HANDLING AND ABATEMENT. After the preliminary observations have been recorded, remove the coating from the joint to be inspected. The amount of coating to be removed shall be governed by the extent of coating disbondment found and the number of features present.

5.3.8 Pipeline Condition and Characterization of Undercoating Electrolytes and Corrosion Deposits

Upon removal of the coating, if any undercoating electrolyte is present the pH of the electrolyte shall be measured and recorded on Form 2 “General Excavation Report”. The pH of the existing electrolyte shall be measured using litmus paper with graduations of 0.5 or a pH meter. If no electrolyte is observed beneath the coating, this shall also be recorded on Form 2 (refer to Appendix J for the forms).

In addition, if any corrosion deposits are observed on the surface of the pipeline beneath the coating, they are also to be characterized and documented. The corrosion deposits shall be qualitatively described based upon their color, texture, and distribution and recorded on Form 4 “Corrosion Deposit Information Sheet”. If there are no corrosion deposits observed on the surface of the pipeline beneath the coating, this shall also be recorded on Form 4 (refer to Appendix J for the forms).

While examining the pipe surface for corrosion deposits, the location and identifiers of any ILI anomalies, corrosion areas, mechanical damage, and deformation features should be marked on the pipe. Digital photos shall be taken of a representative number of corrosion deposits observed at each excavation and the pipe surface at all ILI anomalies. The axial and circumferential pipe measurements and ILI identifiers should be visible in each photograph.

5.3.9 Pipeline Surface Preparation

Accurate assessment of anomalies can only be achieved effectively through adequate cleaning of the affected area using blasting.

Cleaning should be completed in accordance with NACE International and SSPC [Steel Structures Painting Council] specifications to obtain a minimum NACE #2 (SSPC SP10) specification for surface finish that will develop a surface roughness of 2.9 mils or less. This is the recommended method for repairs, which require bonding to the pipe surface such as clock spring sleeves, spray on coatings, tapes, and shrink sleeves. The use of walnut shells as blast media is not allowed due to the oil content in the walnut shells, which saturate the steel surface and cause disbondment of coating materials.

5.3.10 Field Assessment of Detected Anomalies

The nature and extent of each feature shall be determined and documented on the appropriate form; namely, Form 5 "Field Measured/MFL Data Report", Form 7 "Deformation Report", Form 8 "Gouge and Arc Burn report" or Form 9 "MPI Report" (refer to Appendix J for the forms). If there are no features observed on the pipe surface, this shall be recorded on the appropriate forms. The actual wall thickness of the pipe shall be determined and documented by means of a calibrated ultrasonic pulse-echo device and on Form 2 "General Excavation Report".

The following assessment methods shall be performed by experienced Pembina personnel and/or a qualified third party certified NDT Level 2 technician. These individuals should have prior experience with mapping metal loss features using a profile gauge or ultrasonic testing. They should also have a good working knowledge of the applicable codes and regulations.

Appendix J (Forms 5, 7 and 9) depict examples of field-tool comparison tables containing the information that shall be completed for each feature investigated in the field.

The location of each feature reported by the in-line inspection tool and selected for excavation, shall be transcribed onto the pipe surface based upon the distance of the feature from the appropriate girth weld (i.e. either upstream or downstream weld) and its o'clock position or distance from Top Dead Center (TDC) as reported by the tool (Refer to Figure 19 and Figure 20). A "+" can be used to define the location on the pipe surface of the feature reported by the tool; whereas, the overall length and width of the feature reported by the in-line inspection tool shall be noted as a box outlined on the pipe surface (Refer to Figure 20). If available, the ILI identifier as designated by the vendor within the in-line inspection tool data shall be transcribed unto the pipe surface (i.e. ILI#768, Refer to Figure 19 and Figure 20).

The location and dimensions shall be determined for each of the features found in the field and correlated as best as possible to the features reported by the in-line inspection tool. If multiple ILI features are located with a single field defect, an attempt should be made to obtain individual measurements of the length and depth for each ILI feature. High resolution photographs shall be taken to document each field measured feature. These photographs shall include as a minimum, a photograph of the entire feature, and close-up photographs of the longest and/or deepest crack(s) or metal loss within the feature, and as applicable, shall include a measurement scale and any tool reported references which have been transcribed unto the pipe surface.

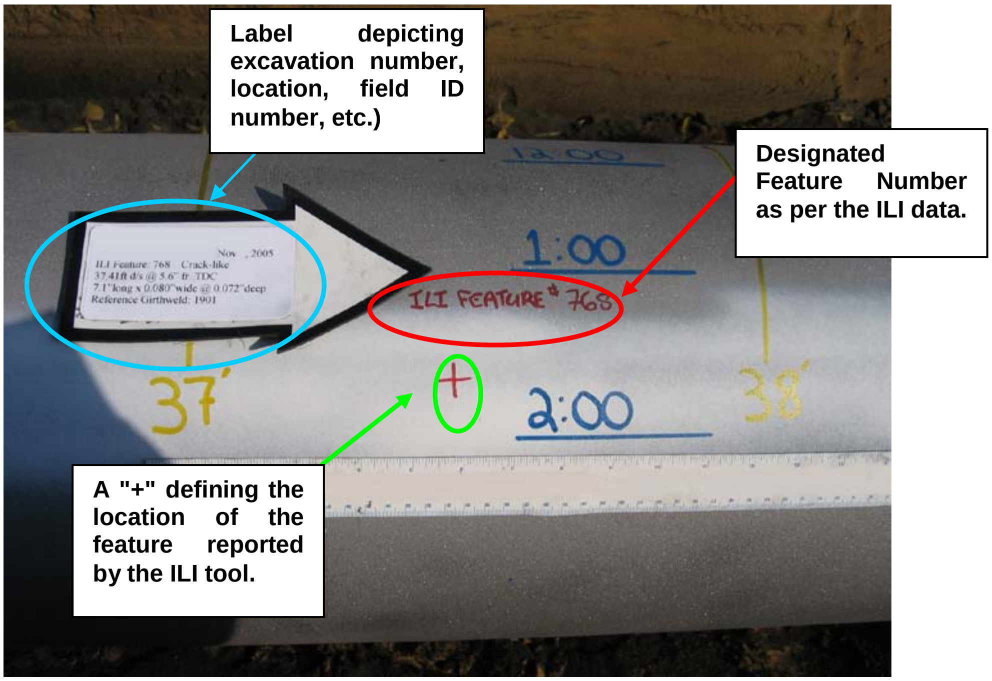


Figure 19 Sample Photograph #1 Depicting the Documentation of the Crack Detection In-line Inspection Data Along the Pipe Surface as Part of the Field Inspection

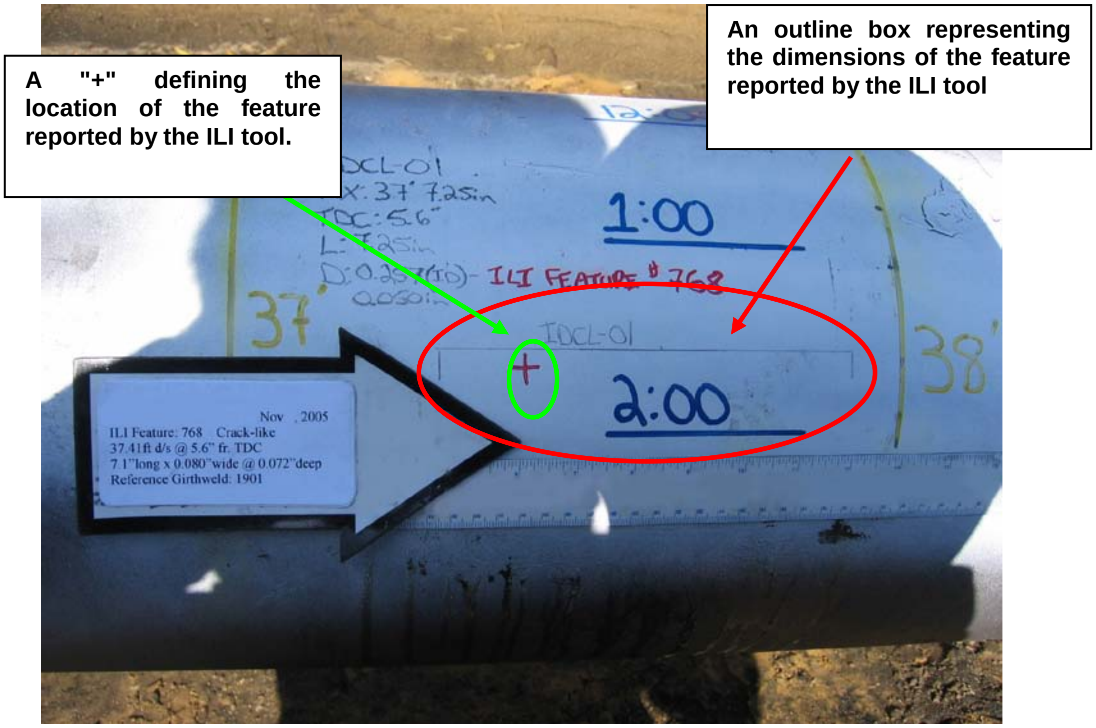


Figure 20 Sample Photograph #2 depicting the Documentation of the Crack Detection In-line Inspection Data Along the Pipe Surface as Part of the Field Inspection

5.3.11 Assessment of Metal Loss Features

a) Each metal loss feature shall be initially measured in the field with respect to its maximum depth and total length, using the Level 1 (clustering) interaction criteria discussed previously in Section 4.1.1. Pembina may or may not elect to undertake Level 2 interaction as Level 2 interactions would only be performed for correlation purposes and only if the in-line inspection vendor has identified groups.

b) Each clustered metal loss feature shall be assessed using the Rstreng 0.85dL methodology.

c) If a metal loss feature fails the Rstreng 0.85dL assessment, Pembina may elect to further assess the feature by mapping it out using a 12.7 mm by 12.7 mm (0.5 inch) corrosion grid, as illustrated in Figure 21, and its burst pressure calculated using the Effective Area methodology.

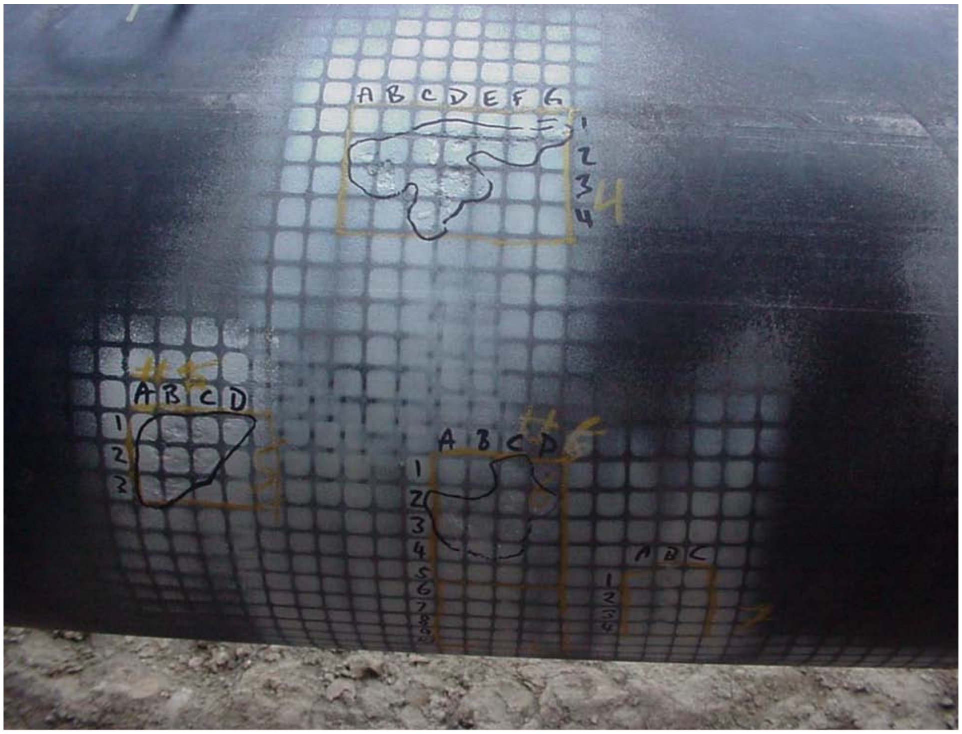


Figure 21 Example of Corrosion Grids for Mapping out Metal Loss Features

d) Circumferentially orientated corrosion shall be assessed in accordance with API RP579 standard (Refer to Appendix C).

e) If it is necessary to undertake the procedures in d), Pembina may elect to undertake the Effective Area calculations for each cluster and group found at the specific excavation site for correlation purposes with the in-line inspection data if an in-line inspection tool was run in the section of pipe being excavated.

f) After magnetic particle inspection to check for cracking (Section 5.3.13.1), the final acceptance of each metal loss feature shall be assessed by comparing its actual maximum depth and actual burst pressure to the parameters described in the repair criteria section of Section 5.4.1.

g) Depending upon the severity of the corrosion and its proximity to a longitudinal seam weld and/or girth weld an ultrasonic examination of the weld may be done to check for any unacceptable defects contained within the welds

The above information shall be recorded on Form 5 “Field Measured/MFL Data Report”. The corrosion shall be mapped using Form 6 “Corrosion Depth Data Sheet” (refer to Appendix J for all forms).

5.3.12 Assessment of Deformation Features

a) A profile gauge (refer to Figures 4 and 5 of Appendix G) or moulding shall be used to measure the profile (i.e. length, width and depth) of the feature at 10° intervals around the pipe's circumference, creating a 3D map image of the feature.

b) Record the start and stop circumferential location of the feature relative to the Top Dead Center (TDC) of the pipe (i.e. 12 o'clock), looking downstream. Record the required measurements of any pipe ovality, dents, wrinkles, and bulges throughout the length of the feature so as to facilitate calculating the size of the feature as detailed in Section 4.2.2.

c) Examine the area of the feature, using ultrasonic inspection, to identify any pipe wall thinning adjacent to the feature's edge.

d) If the feature is located on a girth or seam weld, an ultrasonic examination of the longitudinal seam weld and/or the girth weld in the area of the feature shall be undertaken to identify any unacceptable weld related defects. The purpose being, that if no weld related defects exist, the geometry feature can be assumed to be the same as any geometry feature not associated with a weld.

e) After magnetic particle inspection (Section 5.3.13.1), any cracks, scratches, grooves or gouges located on a geometry feature should be removed by grinding following the procedure in Section 5.5.2.1.

f) Pipeline Integrity is to be contacted whenever wrinkles or buckles are detected. A detailed engineering analysis shall be performed on any geotechnically caused buckles, wrinkles or ripples, to determine the most appropriate long-term method of remediation.

g) Record the appropriate information on Form 6 "Deformation Report" (refer to Appendix J for all forms). Refer to Section 5.4.2 for the acceptance/repair criteria.

5.3.13 Non Destructive Testing

5.3.13.1 Magnetic Particle Inspection

The decision to perform magnetic particle inspection will be made by Pipeline Integrity based upon the:

- Operating stress level of the pipeline
- Coating type and condition
- Diameter of the pipeline, and
- Integrity history of the pipeline

- Type of defects found

To detect the presence of SCC and other crack-like anomalies, the inspection techniques to be carried out is black on white colour contrast magnetic particle in accordance with ASTM E709-08. An AC hand held yoke shall be used for the inspection. As a minimum, the following areas should be inspected:

- Areas of coating disbondment,
- Areas of external metal loss,
- Areas of deformation and mechanical damage, and
- Exposed welds

No oil-based products shall be used.

5.3.13.2 Ultrasonic Testing

Laminations, internal lack of fusion, and other midwall or internal features are identified using ultrasonic testing. The axial and circumferential extent of the features and their depths are to be determined using an approved ultrasonic technique.

5.3.14 Assessment of Crack Related Features

The information that shall be collected for each crack feature detected in the field shall include, as a minimum, the following:

- Alphanumeric identifier

- Distance of the feature relative to the appropriate Girth Weld (i.e. either the upstream or downstream weld)

- Location of the center of the feature relative to TDC or o'clock position

- Width and axial length of the feature

- Measured length of the longest individual crack within the feature and average length of all the identified cracks within the feature

- Presence of interlinking (Yes/No) and the measured length of the entire interlinking crack

- The maximum interlinked crack length

- Whether the feature is located within corrosion (Yes/No), and the associated corrosion feature number.

- The combined maximum depth of the crack feature and corrosion feature (as applicable), the depth of the corrosion only, and the depth of crack feature after the corrosion. (**Note**: the depth of crack feature shall be defined by either actual measurement (i.e. ultrasonic or grinding) or by visual estimation by experienced technicians following the method outlined in section 8.1.1.3.3 of the CEPA SCC Recommended Practices Guide, 2nd Edition. Caution should be used when using this method for weld seam defects and toe cracking as they may not have a consistent surface length to depth ratio. The following is from the CEPA Procedure:

    - Qualitative SCC depth determination utilizes the intensity and length of the SCC indications, as determined by MPI, to estimate depth. The short, less intense indications typically have a depth less than 10% of wall thickness, while longer, darker indications have a depth greater than 10% of wall thickness. Observations of intensity should be combined with conservative aspect ratio rules. The minimum aspect ratio that will allow for an estimation of SCC less than 10% wall thickness should be determined for the pipe segment by sequentially buffing short SCC features until confidence is obtained in the aspect ratio chosen. This value may differ between pipelines with large differences in wall thickness.

- The maximum interlinked crack length after 1 mm of grinding

- The total amount of wall thickness removed by grinding (if applicable), and whether the crack feature was removed (Yes/No).

- If the crack feature was not removed, the depth of the remaining crack measured by ultrasonic testing.

- High resolution photographs of the feature and the cracks within the feature which include a ruler reference and a descriptive label (i.e. excavation number, colony number, date, etc., Refer to Figure 19 and Figure 20).

- Macro photographs of each SCC feature that show the longest interlink length along a ruler (Refer to Figure 22).

- Macro photographs of each crack-like feature after grinding 1 mm.

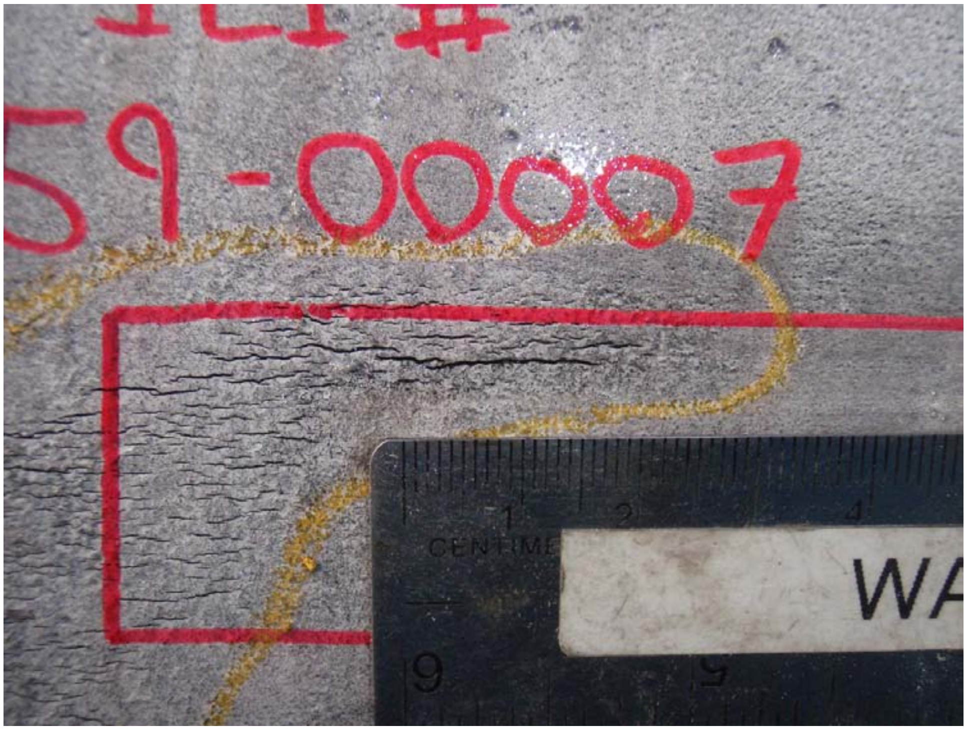


Figure 22 Sample of a Macro Photograph of the Interlink Length of a SCC Colony

The above information shall be recorded on Form 8 “MPI Report” of Appendix J. Refer to Section 5.4.3 for the acceptance/repair criteria.

5.3.15 Other Types of Features

A feature that does not fall into the above categories will be assessed and sentenced by performing an engineering assessment using the applicable codes and sound engineering judgment.

5.4 Defect Repair Criteria

Given the critical and technical nature of an engineering assessment it must only be completed by qualified personnel (either qualified personnel within Pipeline Integrity or qualified third parties) that have been approved by Pembina. All predicted burst pressure calculations are to be done by qualified and experienced personnel and all documentation and calculations must be included.

The defect repair criteria follows the ILI defect acceptance criteria described in Section 4.0.

5.4.1 Repair Criteria for Metal Loss Defects

The repair criteria for corrosion metal loss defects are detailed below:

i. Metal loss defects having a depth >80% of the measured wall thickness, regardless of their dimensions are unacceptable; Note: corrosion with a depth less than 10% of measured wall thickness is permitted regardless of longitudinal length.

ii. Metal loss defects with a predicted burst pressure less than that stated in Table 10 for the appropriate product type and Class Location. The burst pressure shall be calculated using the RStreng Effective Area methodology provided in Section 4.1.2. Pembina may elect to assess the defects based on "at-site" MOP as opposed to MOP; in this case Pembina's MOC process will be followed.

iii. Metal loss features that are concentrated in the seams of electric resistance welded or flash welded pipe or that are located in material likely to exhibit fracture initiation should be assessed as a crack defect (Section 5.4.3).

Table 10 Metal Loss Predicted Burst Pressure Repair Criteria

Product	Class Location	Minimum Predicted Burst Pressure (%MOP)
LVP	All	125%
HVP or CO_2	1	
Gas	1 or 2	
Gas	3 or 4	140%
HVP or CO_2	2, 3, or 4	150%

Source: CSA Z662-2007 Table 8.1

As per CSA Z662-2007 section 10.9.2.7, consideration for internal corrosion that has not been arrested should be made when choosing a repair method.

For narrow width corrosion (such as cracks that have corroded out), the following evaluation should be used to determine if the corrosion should be treated as a crack instead of metal loss:

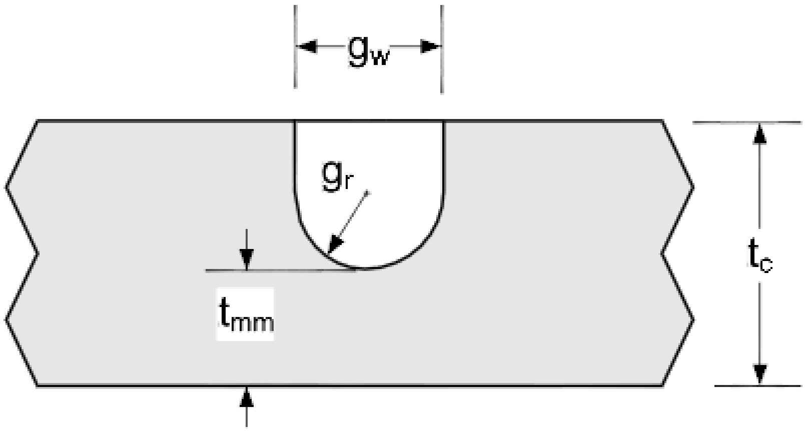


Figure 23 API 579 Figure 5.3 - Groove Like Flaw Dimensions

Assuming that the corrosion radius (g_r) is equal to half of the corrosion width (g_w) then equation 5.10 of API 579 states that if circumferential width of the corrosion is less than two times the depth (both in mm), than the groove should be assessed as a crack feature.

After the assessment has been conducted and the defects failing the above criteria have been repaired utilizing either a temporary or permanent repair method any imposed pipeline pressure restrictions can be removed.

Figure 24 details the decision process in determining the repair requirements for metal loss features.

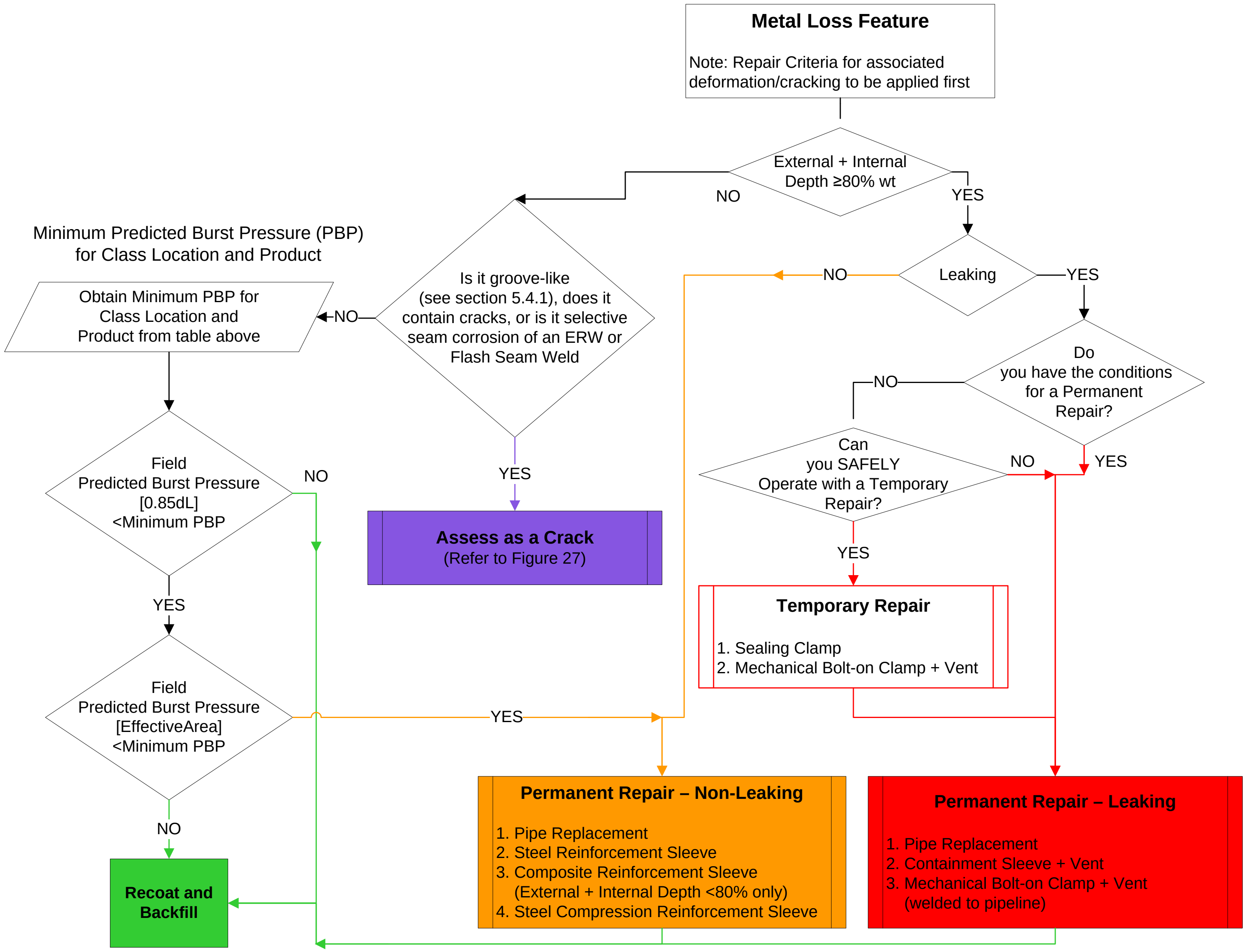


Figure 24 Protocol for Establishing Repair Requirements for Metal Loss Defects

5.4.2 Repair Criteria for Deformation Defects

The repair criteria for geometry defects are detailed below:

i. Dents on the pipe body with a depth ≥ 6 mm in a pipe 101.6 mm OD or smaller or 6% of the outside diameter in pipe larger than 101.6 mm OD

ii. Dents located on a girth weld or seam weld with a depth ≥ 6 mm in pipe 323.9 mm OD or smaller or 2% of the outside diameter in pipe larger than 323.9 mm OD,

iii. Kinked dents (those with a radius of curvature ≤ five times the wall thickness),

iv. Dents located in a girth weld or seam weld that contain unacceptable weld related defects as per CSA Z662-2007 Section 7.11,

v. Dents, wrinkles, or bulges in the pipe body with associated cracks, gouges, grooves, scratches or other stress risers of such dimensions that upon grinding have either a depth >40% of the pipe measured wall thickness or dimensions which exceed the allowable limits specified in ASME B31.G. This criteria also applies to dents with corrosion,

vi. Dents located in a girth weld or seam weld with associated cracks, gouges, grooves, scratches or other stress risers of such dimensions that upon grinding have either a depth >20% of the pipe measured wall thickness or dimensions which exceed the allowable limits specified in ASME B31.G. This criteria also applies to dents with corrosion,

vii. Dents with a low fatigue life as determined by an engineering analysis, and

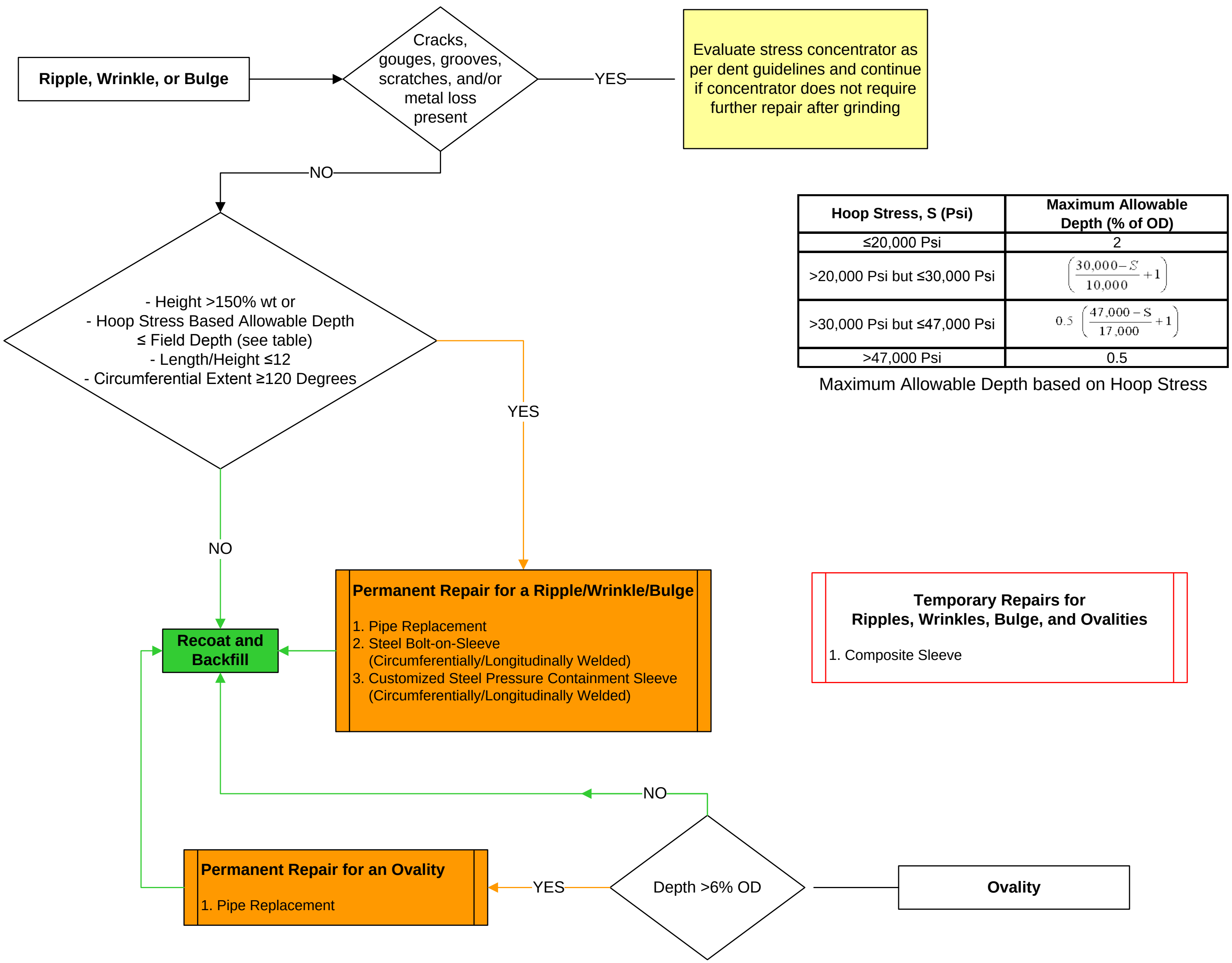
viii. Wrinkles or bulges with a height (measured from peak to valley) of >150% of the pipe measured wall thickness, a wavelength to height ratio ≤12, a circumferential extent ≥120° of the pipe's circumference or a depth (measured from peak to valley) as calculated in Table 11.

ix. Ovality of the pipeline >6% of the pipeline diameter.

Table 11 Maximum Allowable Wrinkle or Bulge Size Based on Actual Hoop Stress

Hoop Stress, S (Psi)	Maximum Allowable Depth (% of OD)
≤20,000 Psi	2
>20,000 Psi but ≤30,000 Psi	$\left(\frac{30{,}000 - S}{10{,}000} + 1\right)$
>30,000 Psi but ≤47,000 Psi	$0.5\left(\frac{47{,}000 - \mathrm{S}}{17{,}000} + 1\right)$
>47,000 Psi	0.5

Figure 25 details the decision process to determine the repair requirement for wrinkles and bulges and Figure 26 details a similar process for dent features.



Hoop Stress, S (Psi)	Maximum Allowable Depth (% of OD)
≤20,000 Psi	2
>20,000 Psi but ≤30,000 Psi	$\left(\frac{30{,}000-S}{10{,}000}+1\right)$
>30,000 Psi but ≤47,000 Psi	$0.5\left(\frac{47{,}000-S}{17{,}000}+1\right)$
>47,000 Psi	0.5

Maximum Allowable Depth based on Hoop Stress

Figure 25 Protocol for Establishing Repair Requirements for Ovalities, Ripples, Wrinkles, and Bulges

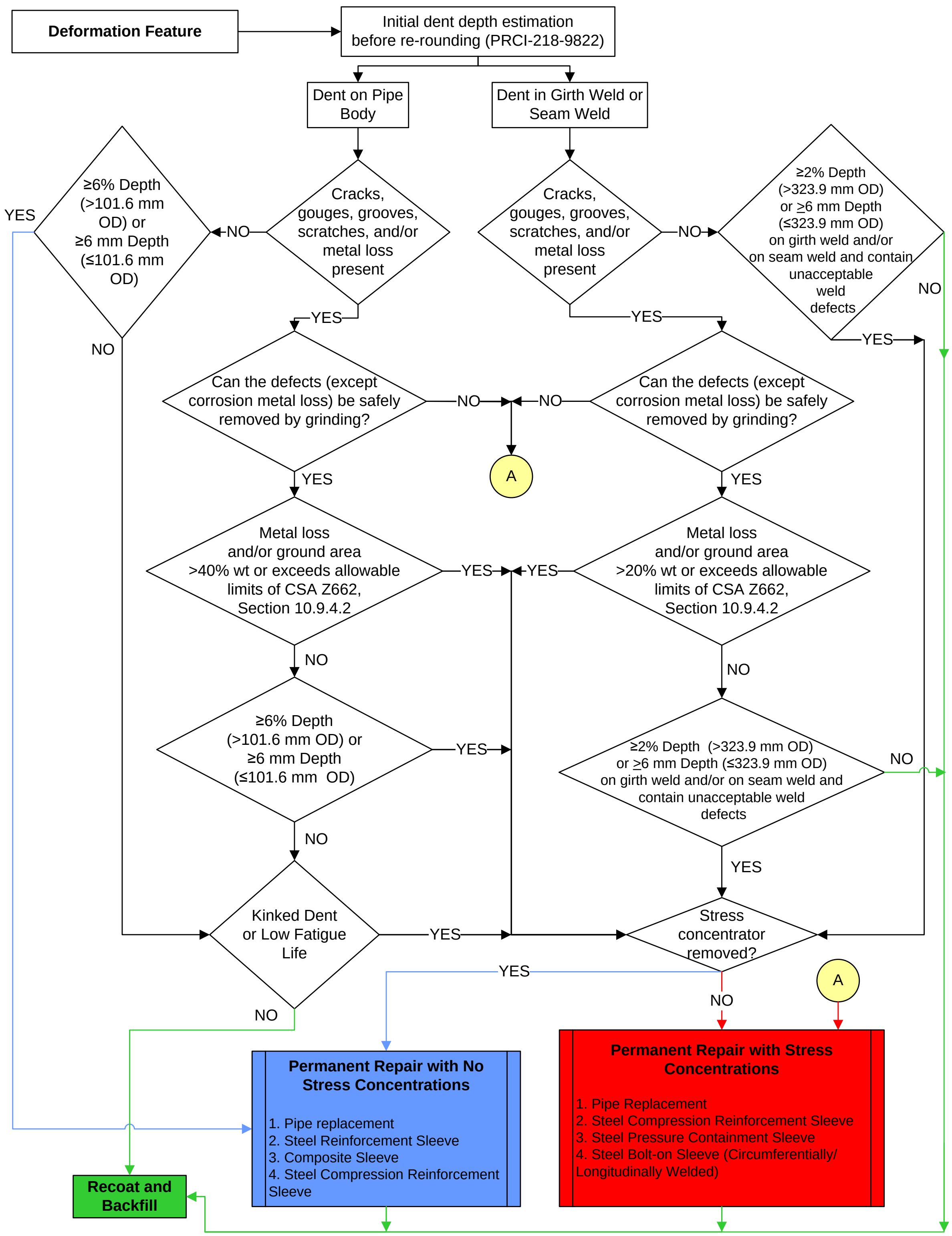


Figure 26 Protocol for Establishing Repair Requirements for Dents

5.4.3 Repair Criteria for Crack-Like Defects

The following defects are unacceptable and require repair:

i. All laminations associated with a girth or seam weld require a non-leaking stress concentrator repair if they are not surface breaking or a leaking repair if they are surface breaking,

ii. All blisters should be assumed to have undetectable cracking within them and repaired with an appropriate repair method,

iii. All SCC and selective seam corrosion with a depth <10% of the measured pipe wall thickness do not require repair if they have an acceptable fatigue life as determined by Pipeline Integrity,

iv. All SCC and selective seam corrosion with a depth >10% of the measured wall thickness and all other external crack related defects must be ground out or sleeved. If the grind depth exceeds 40% of the measured wall thickness or fails the burst pressure assessment detailed in Section 10.10.2.3 Part ii of CSA Z662-2007, the area must also be repaired,

v. All internal crack related defects with a low remaining fatigue life (as determined by Pipeline Integrity) must be sleeved, and

vi. All arc burns must be ground out or sleeved.

Figure 27 details the decision process for determining the repair requirement for crack-like defects.

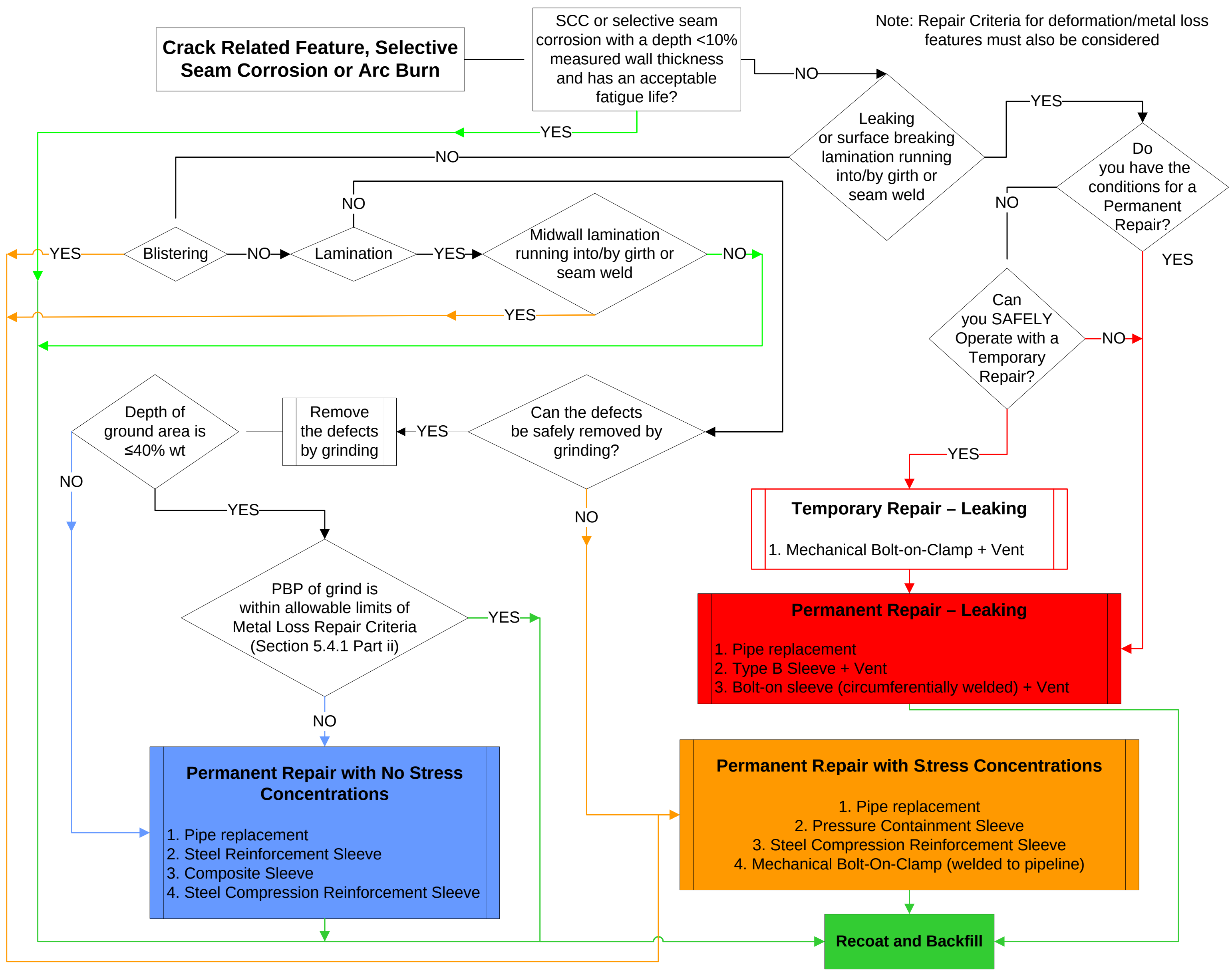


Figure 27 Protocol for Establishing Repair Requirements for Crack-like Defects

5.5 Pipeline Repair

This section covers the approved repair alternatives for pipeline anomalies. Exceptions to these repair methods require an MOC to be written. The final sentencing of all defects and all pipeline repairs shall be discussed between Pipeline Integrity and Pembina's at-site inspector.

Repairs are classified as either permanent or temporary.

Temporary or emergency repairs must be removed within one year unless a MOC is written and the repair is inspected on an annual basis. Emergency repairs (i.e., bolt on sleeves) are used on potentially injurious anomalies until permanent repairs can be completed.

5.5.1 Pressure Reductions during Repairs

The following repairs require pressure reductions, regardless of the product transported:

Table 12 Pressure Reductions for Repairs

Repair Method	Required Action
Re-coating	None
Grinding <10% WT	None
Grinding Pipe Body >10% to 40% WT	Reduction equal to 20% of the highest MOP within the last 60 days
Clockspring™ Installation	See Note 1
Bolt On Sleeve	See Note 1
PETROSLEEVE®	See Note 1
Welded Sleeve	Shut Down[2]
Stopple	Shut Down[2]
Cut Out	Purge/Drain Down

Notes:
1. Per manufacturers directions
2. Shut down for welding but flowing for tapping operation to flush cuttings

5.5.2 Repair Alternatives

Repair alternatives including guidance for selection of the appropriate repair techniques are included in the Pembina OM&P Manual, Part 20.09. In general, repair alternatives include:

- Removal of existing pipe (cut-outs)
- Grinding
- Steel sleeves (pressure containment, reinforcement, and compression reinforcement)
- Temporary bolt-on sleeves
- Composite sleeves

All repairs are to be completed in accordance with Table 10.1 in CSA Z662-2007.

5.5.2.1 Pipeline Repairs – Grinding

The following section details requirements of grinding for all external surface breaking or near external surface crack-related features, gouges, grooves, scratches, seam weld corrosion, arc burns, slivers, scabs, etc. in either the pipe body or seam weld. Grinding cannot be used for repairing laminations with blistering or running into a girth or seam weld. No grinding shall be performed without the consent of Pembina if it is determined that the proposed grinding will exceed 10% of the measured wall thickness.

Depending on the number of crack related features it may be decided by Pipeline Integrity to repair the pipeline with sleeves as opposed to grinding.

The scope of this section is limited to the application of grinding as permitted by CSA Z662-2007 and is based upon the Grinding Procedure detailed in the Canadian Energy Pipeline Association (CEPA) Recommended Practices. The CSA Z662-2007 code includes provisions for grinding as a permanent repair of crack-like and other pipeline defects within allowable limits which are a function of the length and depth of the ground area. A grinding repair within the maximum allowable limits of CSA Z662-2007 Section 10.10.2 is considered acceptable. Grinds above these maximum limits will require an additional repair method.

For grind repairs >10% measured wall thickness a pressure reduction shall be implemented equal to 20% of the highest maximum operating pressure recorded in the last 60 days.

a) An inspection shall be performed in the area of the feature using colour contrast MPI to establish the full extent of the crack-like feature.

b) If a fatigue analysis concludes that SCC or selective seam corrosion defects with a depth of <10% of the pipe measured wall thickness would have acceptable fatigue lives, a sampling of these defects should be ground to validate the depth estimates as outlined in section 5.3.14. If the fatigue analysis indicates that these features do not have an acceptable fatigue life, they should be ground out. It must be indicated on the MPI report whether the depth was based on actual or comparative grinding.

c) All external crack-related features with an estimated depth between 10% and 40% of the pipe measured wall thickness shall be ground out to determine their depth and to permanently repair them.

d) If crack related features with an estimated depth >40% of the pipe measured wall thickness are found Pipeline Integrity should be contacted for the method of repair.

e) All scratches, grooves, gouges, and arc burns with a depth <40% of the pipe measured wall thickness shall be completely ground out to permanently repair them. A representative number of slivers and scabs should also be ground out to confirm their severity; if their severity is deemed unacceptable then all scabs and slivers shall be removed.

f) If the pipeline has been inspected using an ultrasonic crack detection in-line inspection tool, all SCC and other crack related features with an interlinked length ≥25 mm should be ground to 1 mm depth to confirm their interlinked length. In addition, for any crack related features reported by the crack detection tool that will be ground out, sequential grinding (see i) below) shall be used to obtain an accurate length and depth profile of the crack feature.

g) The actual pipe wall thickness in the area to be ground shall be determined by ultrasonic testing. A complete scan of the surrounding area immediately adjacent to the crack-like feature shall be undertaken to determine whether any evidence of internal pipe wall metal loss, weld defects, or other irregularities is present. If any unacceptable defects are found below the feature of interest grinding should not be used to repair the defect.

h) If the crack-like feature is located within a corroded area, the effective depth of the crack-like feature within the corrosion shall be determined by adding the depth of the corrosion and the depth of the crack-like feature from the base of the corrosion.

i) The crack-like feature should be removed through a series of successive grind passes of 0.005” to 0.0010” using a rubber backed or flap 80-120 grit sanding disk. Ultrasonic measurements should be performed between each pass to confirm the remaining pipe wall thickness. The motion of the sanding disk should be parallel to the orientation of the crack-like feature and only light pressure to the ground area to avoid peening of the cracks. Skilled technicians should perform all grinding repairs and personal protective equipment including eye and face protection should be worn at all times.

j) To confirm the complete removal of the crack-like feature, a final non-destructive testing using black on white colour contrast MPI of the ground area should be performed. The complete removal of scratches, grooves, gouges, arc burns, slivers, or scabs shall be confirmed by etching the areas using a 5% Nital solution, to identify any differences in microstructure (Refer to Appendix D for the etchant Procedure). A final ultrasonic wall thickness measurement shall be clearly indicated in the final report.

k) If the crack-like defect is still evident when 20% of the measured wall thickness is removed in the longseam area of pipe manufactured prior to 1970 or 40% of the measured wall thickness is removed in the pipe body or pipe manufactured on or after 1970 (combination of grinding and corrosion), Pipeline Integrity should be contacted for the method of permanent repair.

l) The ground area should be carefully rounded and contoured to aid in the transition between the repair and good metal.

5.5.3 Repair Safety

All repair activities shall be completed in accordance with the safety procedures outlined in Pembina HSE Standards Manual. One specific safety concern during the removal and installation of a new section of pipe is ensuring that proper grounding is maintained at all times. Grounding clamps and wires are to be used during the repair. For the safety of the workers and to prevent arcing during welding, the cathodic protection rectifiers must be turned off before cutting of pipe occurs. Residual magnetic fields may stay on the pipeline for up to a week after the rectifier has been turned off.

5.5.4 Welding

Welding is integral to the pipe repair process. Maintenance welding standards for repairs to all pipes within the Pembina systems and procedures to ensure qualified welders and proper welding procedures are used to complete pipeline repairs are contained in the Pembina Welding Manual.

Procedures in the Pembina Welding Manuals have been qualified to the requirements of CSA Z662 - Latest Edition. In addition, welding safety practices must be done in accordance with Pembina's HSE Manual, Part 4.06. Pembina's Welding Manual attempts to provide approved welding procedures that may be used in a wide variety of maintenance welding application throughout the Pembina systems. As there are slight variations in each test, the individual Weld Procedure Specification (WPS) should be referred to in the Welding Manual.

5.5.5 Requirements for Pipe Replacements

Repair by replacing the affected section(s) of pipeline is permitted for any type of damage, defect, or leak. Repair by this method shall not begin until the pipeline has been depressurized, evacuated, and purged. Prior to cutting into the pipeline, an access hole shall be made to the pipeline so that the contents of the pipeline can be sampled to assure that the pipeline is safe to be cut. Provided below are the minimum requirements for a pipe replacement:

a) The minimum length of pipe replacement shall be at least three pipeline diameters in length and shall as a minimum extend 100 mm beyond both ends of the defective, damaged, or leaking area.

b) The existing pipe at the proposed weld locations should be fully inspected with MPI and UT to check for existing defects. Defects ≤10% wall thickness should be ground out prior to welding; otherwise a new weld location should be chosen.

c) The replacement pipe shall be preferably of equal pipe wall thickness and grade as the existing pipe; however, if the replacement pipe has a different wall thickness than the existing pipeline, calculations shall be done to demonstrate that the replacement pipe meets the minimum design requirements for the given Class location. If the difference in wall thickness between the replacement pipe and the existing pipe varies by more than 2.4 mm, special precautions (i.e. using a transition pup, machine bevelling whichever pipe has the thicker wall thickness, etc.) shall be taken to ensure that the final tie-in welds are made with pipe ends of equal wall thickness.

d) The replacement pipe shall be pre-tested to a minimum pressure level according to Table 13:

Table 13 Minimum Test Requirements for Replacement Pipe

Product	Class Location	Minimum Test Pressure (%MOP)
LVP	All	125%
HVP or CO_2	1	
Gas	1 or 2	
Gas	3 or 4	140%
HVP or CO_2	2, 3, or 4	150%

Source: CSA Z662-2007 Table 8.1

e) All other requirements as per CSA Z662-2007 Section 10.10.3.

5.5.6 Sleeve Inspections after Repairs

After installation of steel sleeves all fillet welds associated with the sleeves shall be inspected using an appropriate NDT method (MPI or UT). If fillet welds were used to attach the sleeves to the carrier pipe they should be inspected upon cooling of the weld and again after 8 to 12 hours.

5.6 Test Stations, Bonds, and Cable to Pipe Connections

Appendix H contains procedures for installing test stations, bonds, and cable to pipe connections.

5.7 Recoating and Backfilling

After the pipeline has been inspected and repaired it shall be recoated and backfilled, as detailed below.

5.7.1 Pipe Preparation

Upon completion of the repair, the pipe surface must be cleaned to ensure strong adhesion of the repair coating. As such, the following procedure must be followed prior to recoating of the pipe:

- Remove dirt debris and grease with a solvent
- Sandblast the area to be recoated to the standards specified in Section 5.3.9.
- Prepare the transition zone where repair coating overlaps with factory coating

5.7.2 Pipe Coating

Until a coating specification is issued, refer to Pipeline Integrity for the coating type to be used.

5.7.2.1 Composite Repairs

In order to aid in the identification of the composite sleeve by MFL in-line inspection tools, metal bands should be placed at the upstream and downstream ends of the composite sleeve after the pipeline is recoated. In addition, magnets should be placed at the upstream and downstream ends of the repair. Appendix I gives an example of a magnet with a strength (> 4,000 Gauss) that would be detected by an MFL inspection.

5.7.2.2 Special Coating Procedure for Steel Sleeve Ends

Apply filler mastic, adhesive mastic, or a Pembina approved equivalent, to seal the ends of the steel sleeve and form two inch bevels from the sleeve outer surface to the carrier pipe outer surface at both ends of the sleeve.

5.7.3 Rock Shield

Rock shield is used on any pipeline where additional protection is required during the backfilling operation and in areas where it is difficult to prevent rocks or frozen soil from damaging the coating. Rock shield would be used in cases where sand padding is not readily available or uneconomical. Rock shield is also used under pipeline clamps for pile support.

5.7.4 Backfilling

During backfill, the soil supporting the pipeline must be properly compacted to avoid slumping. If adequate compaction is not achievable, particularly at any elbows, risers, and valves, sand bags or granular material should be used. Care must be taken when backfilling above ground facilities, e.g. valves, test leads, etc.

6.0 Data Requirements

Pembina requires proper documentation and reporting of all pipeline repairs and maintenance. This record keeping ensures that the optimal amount and quality of information is available for use in current pipeline operations and for assessment of future pipeline repairs. This information is conveyed to Pipeline Integrity through the forms / reports completed by field inspectors. All inspection personnel must be familiar with all applicable assessment and repair information requirements.

This information is to be forwarded to Pipeline Integrity within one week of completing the repair to enable timely assessment. Generally, Pipeline Integrity shall monitor the repair programs and relate the results back to the dig supervisor for the purposes of confirming accuracy and modifying the repair program if necessary.

The following forms provided in Appendix J are to be completed where appropriate:

1. Ditch Profile Report
2. General Excavation Report
3. Coating Data Sheet
4. Corrosion Deposit Information Sheet
5. Metal Loss Correlation Report
6. Corrosion Depth Data Sheet
7. Deformation Report
8. Gouge and Arc Burn Report
9. MPI Report
10. Recoat and Repair Report

In addition, if a cutout is done the following should be included:

a) Copy of mill certifications and hydrotest records

b) Welding procedure used

c) Welder's name and qualification records

d) X-Ray records

e) Photographs of the replacement pipe section

7.0 References

7.1 Regulations

a) Alberta Energy Resources Conservation Board, “Pipeline Regulation AR 91/2005 – Pipeline Act”

b) Alberta Energy Resources Conservation Board, “Directive 019: Compliance Assurance-Enforcement”, July 27, 2005

c) Alberta Energy Resources Conservation Board, “Directive 066: Requirements and Procedures for Pipelines”, December 2005

d) National Energy Board, “Onshore Pipeline Regulations, 1999, SOR/99-294”, Amended September 2008.

e) British Columbia Oil and Gas Commission, “Pipeline Act [RSBC 1996] Chapter 364”.

7.2 Industry Standards

a) Canadian Standards Association Z662-2007: Oil and Gas Pipeline Systems.

b) NACE “In-Line Inspection Recommended Practice”, Standard 0102 2002.

c) American Petroleum Institute Standard 1160, “Managing System Integrity for Hazardous Liquid Pipelines”, 2002.

d) Shell International Exploration and Production, “Specifications and Requirements for Intelligent Pig Inspection of Pipelines”, Version 2.1, November 1998.

e) American Gas Association, Pipeline Research Committee, PR-3-805 [Kiefner, J.F., Vieth, P.H.], “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe”, December 22, 1989.

f) American Society for Testing and Materials (ASTM) Standard E 1049-85, “Standard Practices for Cycle Counting in Fatigue Analysis”, Re-approved 1997.

g) ASME Code for Pressure Piping, B31.8, “Gas Transmission and Distribution Piping Systems,” Appendix R, ASME International, 2003.

h) American Society for Testing and Materials (ASTM) Standard E 709, “Standard Guide for Magnetic Particle Testing”, 2008.

i) NACE International No. 2/SSPC-SP 10, “Near White Metal Blast Cleaning”, Reaffirmed September 2006.

7.3 Industry Documentation

a) Fowler, J.R.; “Criteria for Dent Acceptability In Offshore Pipelines”, OTC 7311, 25th Offshore Technology Conference, Houston, Texas, 3rd-6th, pp 481-493, May 1993.

b) Fowler, J.R., C.R. Alexander, P.J. Kovach, and L.M. Connelly, “Fatigue Life of Pipelines with Dents and Gouges Subjected to Cyclic Internal Pressure”, PD-Vol. 69, Pipeline Engineering, ASME 1995.

c) Fowler, J.R., C.R. Alexander, P.J. Kovach, and L.M. Connelly, “Cyclic Pressure Fatigue Life of Pipelines with Plain Dents, Dents with Gouges, and Dents with Welds”, AGA Pipeline Research Committee, Report PR-201-927 and PR-201-9324, June 1994.

d) Rosenfeld, M.J.; “Guidelines for the Assessment of Dents on Welds”, Pipeline Research Council International, Inc., Contract PR-218-9822, December 1999.

e) Kiefner, J.F. and C.R. Alexander, “Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines (Phase 2),” Addendum to API Publication 1156, Kiefner and Associates, Inc. and Stress Engineering Services, Inc., May 19, 1999.

f) Kiefner, J.F. and C.R. Alexander, “Repair of Pipeline Dents Containing Minor Scratches,” Final Report to PRCI, Contract No. PR 218-9508, Kiefner and Associates, Inc. and Stress Engineering Services, Inc., March 18, 1999.

g) Rosenfeld, M.J., P.C. Porter, and J.A. Cox, “Strain Evaluation using Vetco Deformation Tool Data,” Proceedings of IPC 1998, Volume I, International Pipeline Conference, June 1998.

h) Canadian Energy Pipeline Association, “Stress Corrosion Cracking Recommended Practices”, December 2007.

i) Jaske, C.E., Hart, B.O., and Bruce, W.A., “Pipeline Repair Manual”, Pipeline Research Council International, August 8, 2006.

j) Kiefner, J.F., P.H. Vieth, and I. Roytman, “Continued Validation of RSTRENG”, PRC, International (PRCI), Pipeline Research Committee, Catalogue No. L51749, December 20, 1996.

k) Canada National Energy Board, “Stress Corrosion Cracking on Canadian Oil and Gas Pipelines", November 1996.

l) Canadian Energy Pipeline Association, “Procedure for Developing a Preliminary Assessment of Kinks”, January 2005.

m) Cosham, A., Hopkins, P. “The Pipeline Defect Assessment Manual (PDAM)”, Penspen Limited, 2003.

n) Parkins, R., “A Review of Stress Corrosion Cracking of Pipelines in Contact with Near-Neutral (Low) pH Solutions, Prepared for the Line Pipe Research Committee of PRCI International", April 1999.

o) Vieth, P.H., C.J. Maier, and C.E. Jaske., “Pressure Cycle Fatigue – A Statistical Assessment Approach”, International Pipeline Conference, IPC04-0556, 2004.

p) Beavers, J.A., “Near-Neutral pH SCC: Dormancy and Re-Initiation of Stress Corrosion Cracks”, Final Report – GRI Contract 7045, Gas Research Institute, Chicago, 2003.

q) Beavers, J.A. and J.T. Johnson, “Stress Corrosion Cracking: An Overview Of Field Data Collection,” EPRG / PRCI – 12th Biennial Joint Technical Meeting on Line Pipe Research, Groningen, The Netherlands, May 1999.

r) Jaske, C.E. and J.A. Beavers, “Predicting the Failure and Remaining Life of Gas Pipelines Subject to Stress Corrosion Cracking,” International Gas Research Conference, San Diego, California; November 8 – 11, 1998; Paper TS0-13.

s) Beavers, J.A., C.L. Durr, and S.S. Shademan, “Mechanistic Studies of Near-Neutral-pH SCC on Underground Pipelines.” 37th Annual Conference of Metallurgists, Calgary, Alberta, Canada, August 1998.

t) Kiefner, J.F. and J.A. Beavers, "The History of Stress-Corrosion Cracking in Pipelines in North America," presented at the A.G.A. Operations Conference, Westin Hotel, Seattle, Washington (May 17-19, 1998).

u) Beavers, J.A. and C.E. Jaske, “Near-Neutral pH SCC in Pipelines: Effects of Pressure Fluctuations on Crack Propagation,” Corrosion NACExpo '98, NACE International, San Diego, CA, Paper No. 257, March 1998.

v) Beavers, J.A. and B.A. Harle, “Mechanisms of High-pH and Near-Neutral-pH SCC of Underground Pipelines,” ASME – International Pipeline Conference; Calgary, Alberta Canada, June 1996, Paper No. IPC 96408.

w) Beavers, J.A. and N.G. Thompson, “Effects of Coatings on SCC of Pipelines: New Developments,” 14th International Conference on Offshore Mechanics and Arctic Engineering (OMAE); Copenhagen, Denmark; June 1995, Paper No. 95-886.

x) API 579-1/ASME FFS-1 “Fitness for Service”, Second Edition, 2007.

7.4 Pembina Procedures

Al/Greg - Need correct reference for these:

a) Anon, “Health, Safety, and Environmental Manual”, Pembina Pipeline Corporation

b) Anon, “Pembina OM&P Manual”, Pembina Pipeline Corporation

c) Pembina’s welding manuals

d) Coating specification

Appendix A
Definitions

Above Ground Marker (AGM): Permanent or temporary benchmark on the ground used to reference pipeline surface locations during an In-line inspection run. These pipeline locations are included in the In-line inspection data for chaining or geographic references.

Actual Wall Thickness (t_a): The pipe wall thickness, unaffected by any anomaly, which is measured in close proximity to an anomaly.

Anomaly: An indication, identified by non-destructive testing, of an irregularity or deviation from sound weld or base pipe material (i.e. metal loss, crack, mechanical damage, etc.), which may or may not impair the pipeline integrity in terms of its capacity to withstand internal pressure or resist other stresses imposed on it.

Arc Burn: A localized condition or deposit that is caused by an electric arc and consists of un-melted metal, heat-affected metal, a change in surface profile, or a combination thereof.

API: American Petroleum Institute

ASTM: American Society for Testing and Materials

Bolt-On Clamp: A mechanical sleeve consisting of two steel halves, which are bolted together over the carrier pipe. Leak-proof seals or other devices are located on the inner diameter of the sleeve to prevent leakage. The sleeve may also be welded to the carrier pipe for additional leakage protection.

Buckle: A full or partial collapse of the pipe wall caused by bending or compressive axial loading of the pipeline.

Bulge: A local outward change in surface contour, which is not caused by metal loss.

Cathodic Disbondment: The destruction of adhesion between a coating and the coated surface caused by products of a cathodic reaction.

Cathodic Protection (CP): A technique to reduce the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

CDL, USCD, or UTCD: Crack detection or phased array in-line inspection

CEPA: Canadian Energy Pipeline Association

Class Location: A geographical area classified according to its approximate population density and other characteristics that are to be considered when designing and pressure testing piping to be located in the area.

Class Location Assessment Area: A 1.6 km long geographical area that extends 200 m on both sides of the centerline of the pipeline.

Class Location Boundary: The boundary, perpendicular to the pipe axis, between abutting class locations. The minimum boundaries for any class location must be 200 m from the first and last dwellings in a class location assessment area measured parallel to the pipeline axis. For any given class location, the boundaries may be separated by a distance that is less than, equal to, or equal to the 1.6 km length that is used to define the class location assessment area.

Clockspring: A composite sleeve used for temporary or permanent pipeline repairs.

Close Interval Potential Survey (CIS): A series of pipe-to-electrolyte (pipe-to-soil) potential measurements taken at close intervals (one to five meters) along the pipeline.

Colony: Refers to the grouping of individual stress corrosion cracks.

Coating: The nonconductive material adhering to the pipe or structure to prevent interaction of the steel with soil, water, and/or contaminants.

Construction Anomaly: An anomaly that arises during pipe manufacturing, transporting or constructing of the pipeline, including seam and girth weld anomalies, dents, arc burns, grinding marks, etc.

Continuous Crack Length: A single crack or series of adjoining cracks that would appear as a single indication for a crack detection tool.

Copper-Copper Sulphate Reference Electrode ($Cu/CuSO_4$) (CSE): A reference electrode using an electrolytic copper rod in a saturated copper sulphate solution normally used in soils and fresh waters.

CorLAS™ (Corrosion Life Assessment): A fracture mechanics model used to compute failure stress and the critical flaw dimensions for crack-like/metal loss anomalies and defects.

Corrosion: The deterioration of a material that results from a reaction with its environment.

Corrosion Potential: The mixed potential of a freely corroding metal surface with respect to a reference cell in contact with the same electrolyte (also referred to as native, static, or initial potential).

CP: See cathodic protection

Crack: A planar two-dimensional anomaly caused by stress-induced separation of the steel.

Crack-Field Feature: A crack-field feature is a continuous or discontinuous area of ultrasonic activity identified by the crack detection tool with a width > 25 mm (usually indicative of stress corrosion cracking).

Crack-Like Feature: A crack-like feature is a continuous or discontinuous linear area of ultrasonic activity identified by the crack detection tool with a width ≤25 mm (usually indicative of single, isolated cracks, surface breaking laminations, lack of fusion, undercut, toe cracks, hook cracks, and welding defects).

Criteria for Protection: Standard assessment of the effectiveness of a cathodic protection system.

CSA: Canadian Standards Association

CTSB: Canadian Transportation Safety Board

Current: Quantity of electricity actually flowing in a closed circuit with a symbol "I". Measured in amperes and often shortened to amps or "A". One ampere = 1 coulomb/sec = 6.24×10^{18} electron charges.

Current Interrupters: A device to interrupt the output of a cathodic protection DC power supply on a predetermined cycle. When more than one interrupter is needed, the cycles of all interrupters must be synchronized. The timing of the synchronized current interrupters may be controlled through GPS.

Datalogger: A voltmeter that saves data either on entry or on a timed cycle and can be GPS synchronized.

Defect: An anomaly which has been assessed to be unacceptable and as such requires some form of remedial action be taken in order to restore the integrity of the pipeline.

Dent: Distortion of the pipe wall resulting in a change of the internal diameter but not necessarily resulting in a localized reduction of wall thickness and are not considered to be a bulge.

Dent on Girth Weld: inward deformation of the pipe diameter located on a girth weld (if dent length available) or within 30 cm (1 foot) of a girth weld from the reported dent location.

Dent on Long Seam Weld: inward deformation of the pipe diameter located on a seam weld (if dent width available) or within 5 cm (2 inches) of a long seam weld from the reported dent clock position.

Double Dents: Consist of two dents that overlap along the axis of the pipe, creating a central area of reverse curvature in the longitudinal direction.

Detection Threshold: Minimum detectable size of an anomaly by an inline inspection tool.

Discovery Pressure (Pd): The pressure existing at the location of an anomaly at the time it is discovered or reported.

D/S: Downstream

Dwelling: An inhabited building for residential, municipal, or commercial use.

Electrolyte: A substance, which passes current by means of a chemical reaction; normally a water entrained substance of various salt concentrations or pH.

Engineering Assessment: An assessment of variables using engineering principles.

EP: An abbreviation for an extruded polyethylene pipeline coating system.

ERCB: Energy Resources Conservation Board

FBE: An abbreviation for a fusion bond epoxy pipeline coating system.

Feature: An indication, identified by an inline inspection tool, of an anomaly, change in nominal wall thickness, casing, reference magnet, tees, off takes, valves, bends, anodes, buckle arrestors, external supports, ground anchors, repair shells, markers and Cathodic Protection (CP) connections.

Flow Rate: The speed in which the product is flowing.

Foreign Pipeline or Structure: Any metallic structure that is not intended as a part of a system under cathodic protection.

General Corrosion: Corrosion pitting so closely grouped as to affect the overall strength of the pipe.

Gouge: A surface or local external imperfection caused by mechanical damage that reduces the wall thickness of a pipe. Gouges can be recognized by the sharpness of their edges. A gouge may reduce the local ductility producing a 'hard layer' more susceptible to cracking. The ‘hard layer” is caused by the heat of the damaging process and the plastic deformation.

Global Positioning System (**GPS):** System for providing Universal Transverse Mercator coordinates and associated datum. In the context of technical equipment requirements, “GPS” is a qualifier to identity equipment with built-in GPS receivers for timing and/or physical positioning.

Grinding: Reduction in wall thickness by removal of material by hand filing or power disk grinding.

Groove: Long and narrow channel or depression of the internal or external pipe surface characterized by smooth edges and continuity in length. Grooves can be aligned longitudinally or circumferentially to the pipeline axis.

Groundbed: A group of anodes in a single location.

Heat Affected Zone: That portion of a weld consisting of base metal that has not been melted but whose microstructure or mechanical properties have been altered by the heat of welding.

Historical Pressure (P_h): A pressure greater than the discovery pressure that is known to have existed at the anomaly location after the anomaly was present in its current state (less then 60 days). A previous hydrostatic test pressure can be used as a historical pressure if it meets the time requirements.

Holiday (coating): A discontinuity in a protective coating that exposes the unprotected surface to the environment.

Hook Cracks: Hook cracks, also called "Upturned Fiber Imperfections" are metal separations, resulting from imperfections at the edge of the plate or skelp in the weld zone, parallel to the surface, which turn (curve) toward the internal or external pipe surface when the edges are upset during welding. Hook cracks are a phenomenon only associated with Flash Butt Welds and Electric Resistance Welds (ERW).

ID: Inner Diameter

Imperfection: An anomaly which has been assessed to be acceptable and as such requires no form of remedial action be taken in order to restore the integrity of the pipeline other than removing any stress concentrators present and recoating the affected area.

In-line Inspection (ILI) Tool: Instrumented equipment that can travel internally along a pipeline performing a non-destructive examination of the pipeline while in operation.

Inclusion-Like: An inclusion-like or "Slag Inclusion" is foreign material or non-metallic particles, entrapped in the base metal, weld deposit or between weld metal and base metal during solidification (i.e. surface-parallel inclusion). Common defects include shell/slivers, inclusions extended by rolling, laminations, linear slag lines and linear porosity. In ERW pipe inclusions are precursors to hook cracks if they exist in large quantities at the edges of the skelp used to form the pipe.

Instant Off Potential: The measured pipe-to-electrolyte potential taken immediately after all influencing cathodic protection systems have been de-energized. This is also referred to as the polarized potential.

IR Drop: A voltage caused by the passage of current through a resistance. In this context it is the voltage difference between an "On" and "Off" pipe-to-electrolyte potential.

KAPA™ (<u>K</u>iefner & <u>A</u>ssociates, Inc. <u>P</u>ipe <u>A</u>ssessment): A software tool used to calculate the failure pressure levels of longitudinally-oriented part-through wall flaws of varying depths in pressurized pipe.

Kinked Dent: A dent with a radius of curvature ≤ five times the wall thickness (PDAM)

Lack of Fusion: Lack of fusion, also called "Incomplete Fusion" for submerged arc welds or a "penetrator" for electric flash welds, is a condition of lack of complete coalescence of some portion of the metal in a weld joint and longitudinal seam weld or a localized spot of incomplete fusion.

Lamination: A plane of non-fusion in the interior of steel that forms during the steel manufacturing process. In rolled plate, laminations typically are parallel to the plate surface and are not detrimental to pipeline integrity unless they are in close proximity to a weld or structural discontinuities or are in a hydrogen charging service.

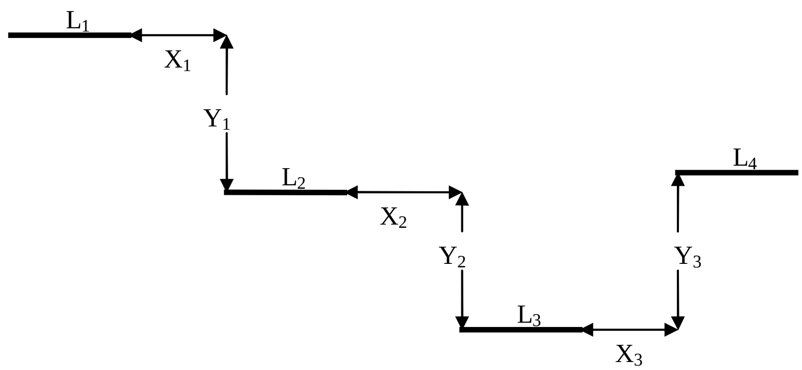
Leak: The passage of product through a crack, hole, or other fault in the wall of the pipeline.

Long Term Assessment: A process to create a remediation program and set an ILI re-inspection interval by predicting the remaining life of features that do not fail the short term assessment process.

mA: Milliampere (10^{-3} Amperes)

Maximum Operating Pressure (MOP): The maximum pressure which piping is qualified to be operated at.

Maximum Interlinked Crack Length: The maximum interlinked crack length is a measure of the total length of a series of interacting cracks as defined in the Canadian Energy Pipeline Associations' (CEPA's) SCC Recommended Practices and as summarized below:



The interacting circumferential distance between two cracks is evaluated using the following formula:

$$Y_1 \leq \frac{0.14\ (L_1 + L_2)}{2}$$

where: Y is the actual circumferential separation between two cracks
L_1, L_2 are crack lengths

The axial separation distance between two cracks is evaluated using the following formula:

$$X_1 \leq \frac{0.25\ (L_1 + L_2)}{2}$$

where: X is the actual axial separation between two cracks
L_1, L_2 are crack lengths

Mechanical Damage: Pipeline damage that includes dents, bulges, wrinkles, buckles, gouges, scratches, or any combination thereof.

Metal Loss Anomaly: An area of pipe wall with a measurable reduction in thickness.

Metallurgical Anomaly: An area of metal, excluding; 1) intentionally deposited filler metal or factory fabricated seams and their heat-affected zones; 2) metal affected by induction bending, and; 3) areas where cathodic protection (CP) leads are attached, in which the microstructure has been altered from that of the parent metal by local contact deformation or where the parent metal has been transformed by local heating and cooling.

Mid-Wall Anomaly: Any anomaly that does not open to either the internal or external surface.

Minimum Allowable Wall Thickness (tm): The nominal wall thickness minus the allowable thickness tolerance of the relevant pipe specification.

Minimum Remaining Wall Thickness (tr): The minimum wall thickness that exists within an anomaly, after any stress concentrator or metallurgical anomaly has been removed by grinding.

Minimum Sleeve Wall Thickness (ts): The minimum wall thickness for a sleeve, with a given Specified Minimum Yield Strength (SMYS), to conform to the requirements of these procedures.

Mitigation: Activities and programs intended to reduce the severity or impact prior to, during or following an emergency.

MOC: Management of Change

MPI: Magnetic Particle Inspection

mV: Millivolt (10^{-3} Volts)

NACE: NACE International (formerly National Association of Corrosion Engineers)

Native Potential: (see Corrosion potential)

NEB: National Energy Board

Nominal Wall Thickness (tn): The pipe wall thickness specified by the pipeline design criteria.

Non Destructive Testing: test methods used to examine an object, material or system without impairing its future usefulness (American Society for Nondestructive Testing).

Not-Decidable: A feature that meets all the standard analysis selection criteria (length, sensor overlap, and reflection amplitude) but the characteristics of the reflector do not fulfill all of the criteria of a single feature type.

Notch: A V-shaped or U-shaped indentation or discontinuity in the metal surface.

Notch-Like: A notch-like indication is a surface imperfection or stress concentrator characterized as a gouge (mechanical removal of metal on the surface of a pipe), groove, rolling defect (i.e., laps or shells), scratch, undercut, or arc burn that can lead to crack initiation under cyclic loading due to its stress concentrating shape.

Off Potential: see Instant off potential

OGC: British Columbia Oil and Gas Commission

Ohm's Law: The relationship between volts (V), current (I) and resistance (R).

ON Potential: The measured pipe-to-electrolyte potential with cathodic protection current applied. The components of an ON potential include the native potential, polarization, and IR Drop.

$V = I \times R$ ($I = V/R$ or $R = V/I$)

Operational Stress Level: The stress in the circumferential direction of a pipeline that is solely attributable to the pressure inside a pipeline.

Permanent Repair: A repair that is engineered to last for the life of the pipeline.

pH: A measure of acidity or alkalinity.

Pipe Mill Anomaly: An anomaly that arises during manufacture of the pipe, such as a lap, sliver, lamination, non-metallic inclusion, roller mark, or seam weld anomaly.

Pipe-to-Electrolyte (pipe-to-soil) Potential: The potential difference between the pipe metallic surface and the electrolyte (soil) that is measured to a reference electrode in contact with the electrolyte.

Polarization: The deviation from the corrosion potential of an electrode resulting from the flow of current between the electrode and the electrolyte.

Polarized Potential: The potential across the structure/electrolyte interface to a reference electrode that is the sum of the corrosion potential and the cathodic polarization (see also instant off potential).

Rectifier: A device to convert AC power to DC power.

Reference Weld: The nearest exposed upstream or downstream girth weld, during an excavation, which will provide a known location where measurements can be taken to any anomaly(s) and the end boundaries of the exposed pipe.

Regulator: A provincial or federal governing body that regulates the actions of pipeline companies.

Repair: The range of actions that Pembina could take to address an integrity problem.

Repair Pressure (Pr): The pressure at the anomaly location at the time the repair is performed.

Resistivity: A materials resistance to electric current flow through an area (A) and length (L) of known dimension and expressed in ohm-unit of that dimension (e.g. Ohm-cm, Ohm-m). The relationship of resistivity (ρ) to resistance (R) is given by:

$$\rho = R\frac{A}{L}$$

ROW: Right of Way

Rupture Pressure Ratio (RPR): The predicted burst pressure of a feature divided by the maximum operating pressure.

SCADA: Supervisory Control and Data Acquisition

Scratch: A small linear mark in the metal surface caused by scraping a sharp object along the pipe surface.

Sealing Clamp (Smith Clamp): A steel ring with a drawing bolt and a pilot guide/cone which is installed directly into the pit-hole. Pressure is applied behind the cone by a force screw and the clamp is secured by the drawing bolt to provide a permanent leak repair.

Shielding: Preventing or diverting the cathodic protection current from its intended path.

Shorted Casing: A road or railroad casing that is in metallic contact with the pipe.

Short Term Assessment: A process based on regulations, standards, and best practices to determine if an ILI reported feature requires remediation or can be assessed using the Long Term Assessment process.

Soil Resistivity: The resistivity of the soil normally expressed in ohm-cm.

Steel Reinforcement Compression Sleeve: A mechanical steel sleeve, consisting of two halves which are preheated during installation and welded, placing the carrier pipe, at the location of the repair, in compression, thus eliminating the ability of crack-like defects to continue growing.

Stopple: A full branch split tee fitting for a pipeline.

Stress Concentrator: A crack, gouge, scratch, notch, or groove that will appreciably increase the local intensity of any stress applied to the pipeline.

Stress Corrosion Cracking: Is a form of environmental degradation, which involves the interaction of corrosion processes and tensile stresses to cause the formation of micro-cracks on the external surface of the pipeline. These micro-cracks typically form in "colonies".

Stress Corrosion Cracking Severity Categories: from CEPA's SCC Recommended Practice:

I) SCC features with a failure pressure greater than or equal to 100% of the product of the MOP and a company defined safety factor (failure pressure typically equating to 110% of SMYS).

II) SCC features with a failure pressure less than 110% of the product of the MOP and a company defined safety factor, but greater than or equal to the product of the MOP and a company defined safety factor (failure pressure typically 100% SMYS).

III) SCC features with a failure pressure less than the product of the MOP and a company defined safety factor but greater than the MOP.

IV) SCC features with a failure pressure equal to or less than the MOP.

Temporary Repair: A repair that is to be replaced by a permanent repair within a two year period unless it has been determined via an engineering assessment to still be an adequate repair for an extended period of time.

Total Length of In-Line Inspection: Distance of inspection run between a launcher and receiver.

Steel Reinforcement Sleeve: A cylinder of steel placed over an anomaly in a pipe using two half cylinders that are joined by two longitudinal seam welds.

Steel Pressure containment Sleeve: A cylinder of steel placed over an anomaly or damage in a pipe, using two half cylinders that are joined by two longitudinal seam welds and fillet welded to the pipe at both ends of the cylinder.

U/S: Upstream

Voltage: An electromotive force or a difference in electrode potentials (Volts)

Weld Anomaly: A weld anomaly is the classification used for ultrasonic indications located in the longitudinal seam weld or its heat-affected zone that do not meet the requirements of a crack-like classification. Weld anomaly calls may arise from real weld related features or from geometric and/or manufacturing related flaws. The following would be classified as "Weld Anomalies":

- weld cracks
- hook cracks
- shrinkage cracks
- lack of fusion
- undercut
- plate misalignment (high-low)
- irregular trim, excessive trim and/or inadequate trim

Wenner 4-pin Method: A test procedure to determine the resistivity of soil using four pins. The spacing of the pins (a) is the approximate depth that the soil resistivity is averaged. A current is impressed through two outside pins and a voltage is measured between the two inside pins. The resistance (R) is calculated from Ohm's Law and the resistivity (ρ) is determined by:

$$\rho = 2 \Pi a R$$

Wrinkle: Transverse surface irregularities normally found in the crotch of a pipe bend. Wrinkles can typically be recognized as ripples on the inside of a bend.

WT: **Wall Thickness**

Appendix B
Checklists

The following checklist provides a means to verify that the key elements of this procedure have been or are scheduled to be completed

1.1 Excavation Program Development

Yes	No	N/A	
☐	☐	☐	Has a MOC been written if the predicted burst pressure of the defects will be compared to “at-site” pressure instead of the maximum operating pressure?
☐	☐	☐	For those features requiring immediate action, have the necessary leak detection survey(s) and pressure reduction(s) been implemented?
☐	☐	☐	For those features requiring immediate action has an optimum timeframe for conducting the repairs been established?
☐	☐	☐	With the in-line inspection compliance assessment completed, has the required excavation program been developed and optimized?
☐	☐	☐	If ASARP features cannot be excavated within 18 months of receiving the ILI report, has a MOC document been written?

1.2 Excavation Program Planning

Yes	No	N/A	
☐	☐	☐	Has the excavation location been properly identified and landowners/foreign facility owners identified?
☐	☐	☐	Have the necessary Company departments that could potentially be involved in the excavation program been notified of the program and of their role(s) and responsibility(s)?
☐	☐	☐	Have the necessary Access and Activity approvals been obtained?
☐	☐	☐	Have all the "safety-related conditions" been identified and addressed?
☐	☐	☐	Have all the "environmental-impact situations" been identified and addressed?
☐	☐	☐	Have the affected landowners and foreign facility owners been contacted and have the necessary permit(s) been obtained?
☐	☐	☐	Are the qualified contractors prepared to complete the excavation program as per the established schedule?
☐	☐	☐	Are the required materials available for the excavation program as per the schedule?
☐	☐	☐	Has a detailed work schedule and budget, if required, been completed and approved?

1.3 Excavation Program and Execution

Yes	No	N/A	
☐	☐	☐	Have all the final changes to the excavation program been effectively communicated to all participants (i.e. Company departments, contractors, and project team)?
☐	☐	☐	Has the "one-call" system, operators of adjacent facilities, and the landowner(s) impacted by the planned excavation activities, been notified within a reasonable timeline, if there are no applicable standards?
☐	☐	☐	Has the necessary pressure reduction been implemented prior to any examination of a feature or leak? Have the necessary operational procedures been implemented to monitor and maintain the required pressure reduction?
☐	☐	☐	Has a pre-job meeting with all key participating personnel been completed?
☐	☐	☐	Has an on-site meeting with all participating personnel been completed?
☐	☐	☐	Have the procedures for pipeline excavation and assessment been followed and documented?
☐	☐	☐	Have the feature assessment results been documented and compared to the reported in-line inspection data?
☐	☐	☐	Has the repair criteria been reviewed and the appropriate repair method selected?
☐	☐	☐	Has the repair been completed in accordance with the repair criteria?
☐	☐	☐	Has a MOC document been written for any non- standard repairs or temporary repairs that will remain on the pipeline for over one year?

1.4 Documentation

Yes	No	N/A	
☐	☐	☐	Have all the forms and documentation been completed and sent to Pipeline Integrity within one week of completing the excavation?

______________________	______________________	____________
Signature	Name	Date

Appendix C
Circumferential Metal Loss Acceptance Criteria

API RP579 Standard – Circumferential Metal Loss Acceptance Criteria

The figure below, from API RP 579, provides the basis for evaluating the acceptability of a circumferentially orientated metal loss feature (i.e. corrosion and/or ground areas).

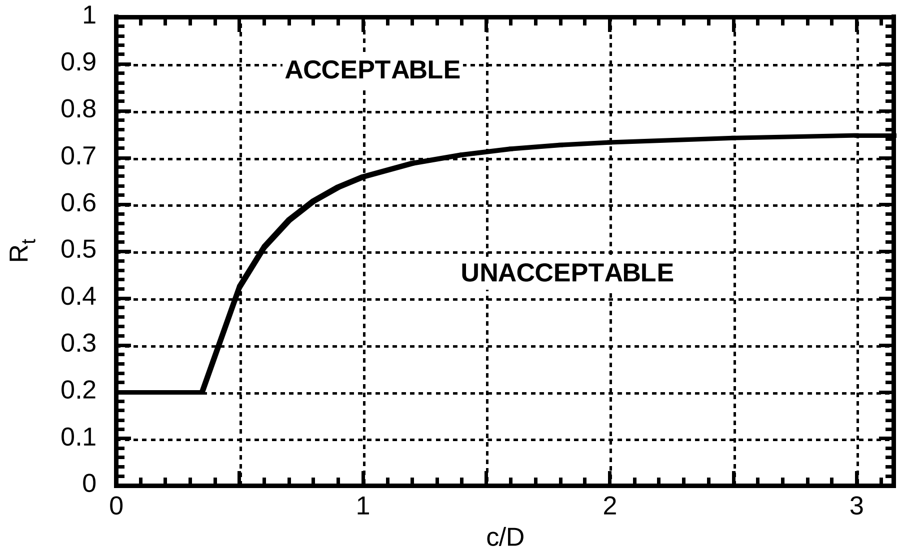


Figure C.1 Allowable Limits of Circumferential Metal Loss

Where;

R_t is the remaining wall thickness ratio = minimum measured thickness/minimum required thickness.

c/D = circumferential flaw extent/pipe diameter.

Appendix D
Etchant Procedure

1.0 Introduction

Nital is a mixture of concentrated Nitric Acid and Methanol. For the purposes of performing pipeline integrity related assessments a 5% mixture is required. Nital is used to etch the pipe surface to verify complete removal, following grinding, of any altered microstructures that maybe caused by arc burns and/or mechanical damage (i.e. gouges, scratches, grooves, etc).

2.0 Preparation and Handling of 5% Nital Solution

A 5% nital solution is made by adding 5 ml of concentrated nitric acid to 95 ml of methanol.

ALWAYS ADD THE NITRIC ACID TO THE METHANOL AND NOT THE METHANOL TO NITRIC THE ACID.

Approximately 250 to 500 ml (8 to 16 ounces) of the 5% Nital solution shall be pre-mixed, in a glass beaker under a fume hood, while wearing the appropriate personal protective equipment. The pre-mixed solution shall then be transferred to a screw-top plastic bottle, prior to mobilization to the excavation site. Packing tape shall then be used to provide extra assurance that the lid is securely in place for transportation to the field. The plastic bottle containing the pre-mixed solution shall be transported in the upright position in a Styrofoam or other suitable container for transporting a liquid. The 5% Nital solution is **not** to be made in the field. The respective MSDS sheets for both the Nitric Acid and Methanol shall always accompany the pre-mixed 5% Nital solution. In the field the pre-mixed solution shall be transferred, as necessary, from the screw-top plastic bottle to a 15 ml plastic squeeze bottle to facilitate the actual etching procedure on the pipe surface.

3.0 Etching Procedure

3.1 The arc burn and/or mechanical damage (i.e. gouges, scratches, grooves, etc) shall be removed through a series of successive grind passes of 0.005” to 0.010” using a rubber backed or flap 80-120 grit sanding disk. Ultrasonic measurements shall be performed between each pass to confirm the remaining pipe wall thickness. The motion of the sanding disk should be parallel to the orientation of the arc burn and/or mechanical damage. Skilled technicians should perform all grinding repairs and Personal Protective Equipment including eye and face protection should be worn at all times.

3.2 Once the arc burn and/or mechanical damage has been removed and the pipe cooled, the 15 ml plastic squeeze bottle shall be used to apply a slow steady stream of the 5% Nital solution over the ground area for approximately five to eight seconds. The pipe surface shall then be visually inspected after 30 to 40 seconds for any evidence of localized differences in the appearance of the pipe surface. Altered microstructures caused by arc burns and/or mechanical damage will have a “dull grey” appearance while the unaltered microstructure will have more of a “shiny” appearance.

When using the Nital solution, appropriate Personal Protective Equipment shall always be used. An eye wash bottle shall always be in close vicinity to the technician when using the Nital solution, in the unlikely event that any of the Nital splashes in someone’s eyes.

3.3 Steps 3.1 and 3.2 are to be repeated until there is no further evidence of the arc burn and/or mechanical damage.

3.4 The final ground area shall be assessed for acceptance in accordance with Section 5.4.1.

Appendix E
Characterization of Terrain Conditions

Table E.1, Table E.2, and Table E.3 provide descriptions of topography patterns, soil types, and drainage conditions, respectively.

Table E.1 Descriptions of Topography (Landform) Pattern

Description	Type	Abbreviation
• Regular sequence of gentle slopes from alternating concave and convex patterns (wavelike pattern).	Undulating	(U)
• Sharp crested; usually with steep side slope.	Ridged	(R)
• Sloping surface	Inclined	(I)
• Topographically low lying area	Depressed	(D)
• Flat to very gentle inclined	Level	(L)
• Side slope of mountain range	Side Slope	(S)

(Source – Marr Associates, 1996)

a) Descriptions of Site Position (from Ontario Institute of Pedology – 1985)

i. **Crest:** the uppermost portion of a slope

ii. **Upper:** upper portion of a slope, immediately below the crest

iii. **Lower:** lower portion of the slope, immediately above the toe

iv. **Toe:** the lowermost portion of the slope

v. **Depression:** any area that is concave in all directions

vi. **Level:** area that is horizontal with no distinct aspect

Table E.2 Soil Type Description

Description	Soil Environment Description
• Sandy and/or gravel textured, usually stratified – includes alluvial sands and gravels derived from relict watercourses.	Fluvial/Glaciofluvial
• Variable soil texture • Variable size range of stones • Sands and gravel • Clay and silt • >1m to bedrock	Till Deposits
• Organic over Clay	Organic
• Clayey to Silty Fine Textured Soils	Lacustrine
• Organic over Sands and/or Gravels	Organic
• <1m of Soil cover over Rock	Rock
• Commonly rocky, gravely textured derived, non-recent deposits • No structure • (Arid and Mountainous Environments)	Alluvial
• Lakes, swamps, rivers	Waterways Creeks

(Source – Marr Associates, 1996)

Table E.3 Drainage Descriptions

Description	Drainage Type	Abbreviation
• Oxidizing environment • Upland areas	Well	(W)
• Alternating oxidizing and reducing environments • Dependent upon fluctuation of water table	Imperfect	(I)
• Primarily reducing conditions • May be saturated throughout most of the season • Reducing environment	Poor	(P)
• Reducing conditions throughout entire year • Saturated year round • Low lying to depressional areas	Very Poor	(VP)
• As above (VP) • Standing Water • Pipe surrounded by organic soil	Very Poor – Very Poor	(VP-VP)

(Source – Marr Associates, 1996)

Appendix F
Characterization of Coating Conditions

Provided in Table F.1 is a process for characterizing the condition of tape and asphalt coatings.

Table F.1 Qualitative Definitions used to Characterize Coating Conditions

Coating Conditions	Extent of Tenting (applicable to tape only)	Description of Disbonded Coating
Excellent	Very Minor to non-existent	Very good adhesion; less than 1% disbondment; an occasional holiday; asphalt exhibits continuous thickness; no electrolyte beneath the coating.
Well	Minor, intermittent	1 to 10% disbondment; scattered holidays; isolated soil stresses with no associated deposits; clear electrolyte; good adhesion.
Fair	Intermittent	10 to 50% disbondment; intermittent soil stress; coating damage; scattered to numerous holidays; random areas of poor adhesion; brittle coating (asphalt).
Poor	Continuous	50 to 80% disbondment; numerous holidays; multiple or continuous areas of poor adhesion; interlinked soil stress with associated deposits; coating damage; very brittle coating (asphalt).
Very Poor	Continuous	>80% coating failure; no adhesion, numerous holidays; interlinked soil stress with associated corrosion deposits; coating damage; very brittle coating (asphalt).

(Source – Marr Associates, 1996)

Appendix G
Typical Defect Photos

Figure 1: General Corrosion

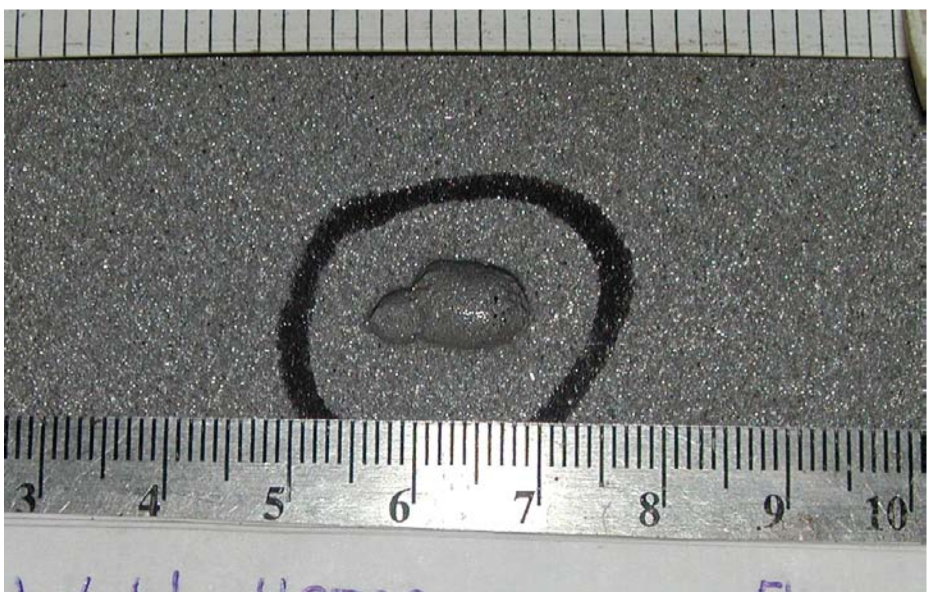


Figure 2: Pitting Corrosion

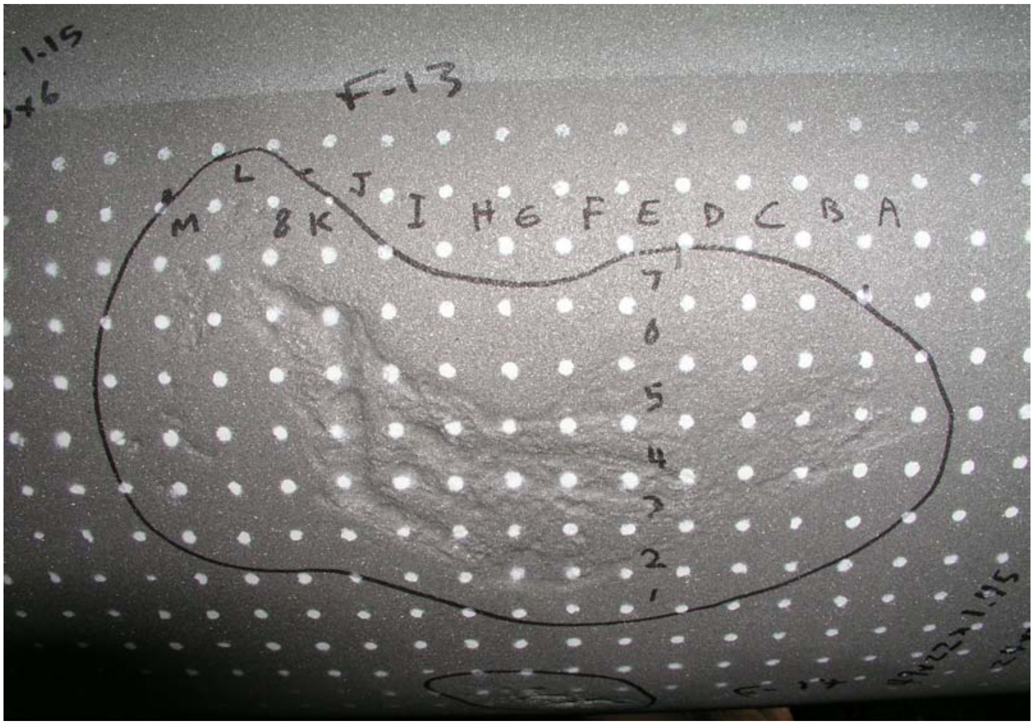


Figure 3: Corrosion Mapping Using a Grid

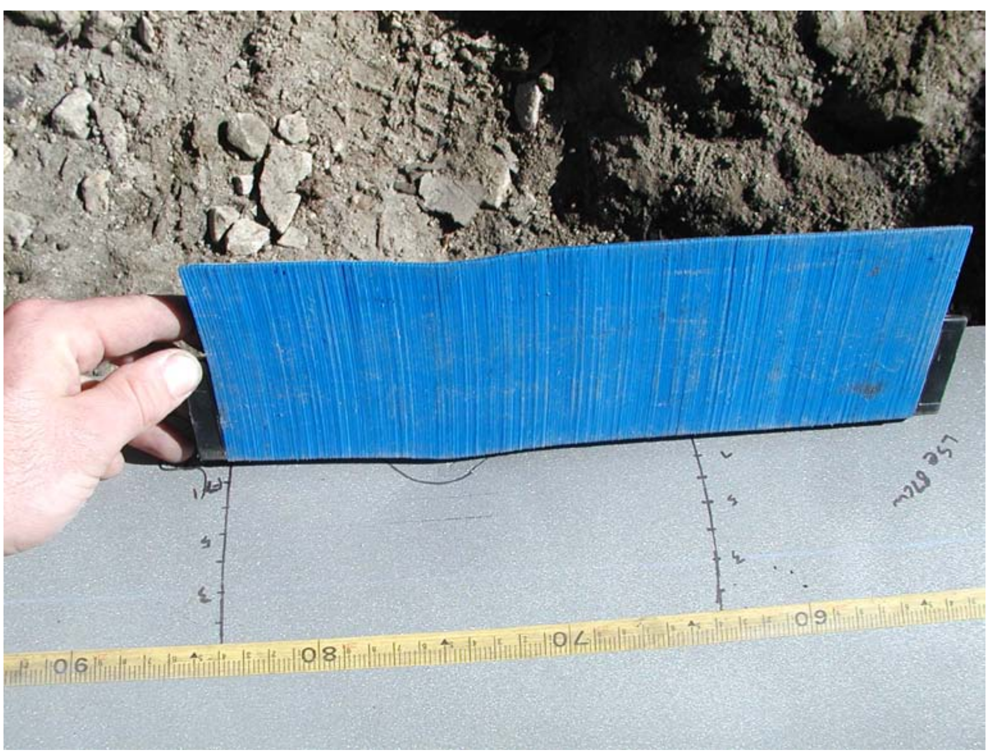


Figure 4: Dent Profile Gauge

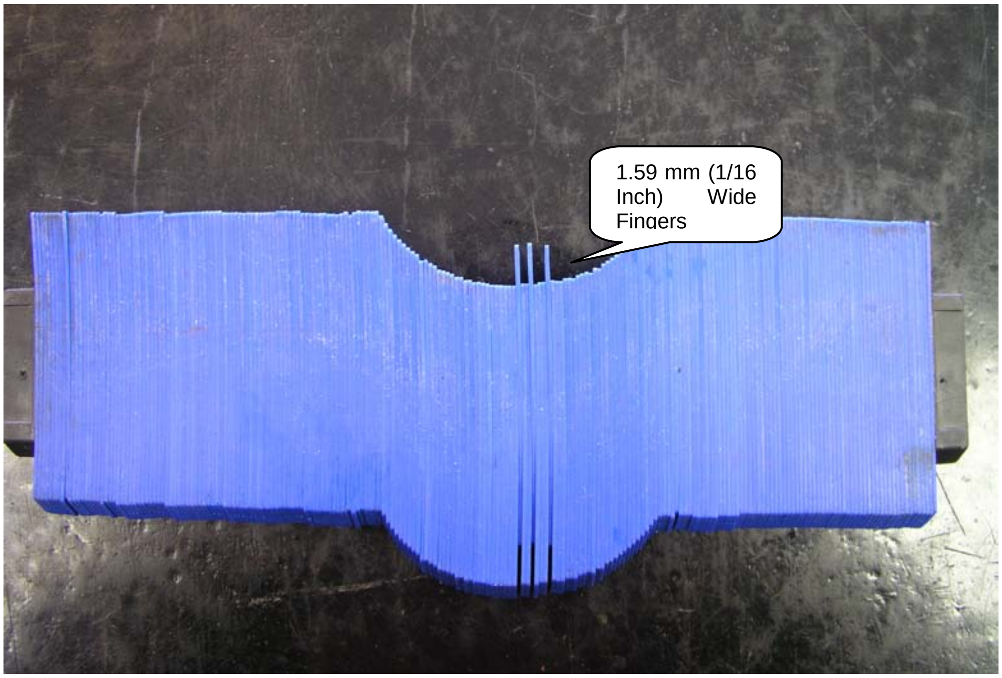


Figure 5: Dent Profile Gauge

Figure 6: Pipeline Dent

Figure 7: Pipeline Buckle

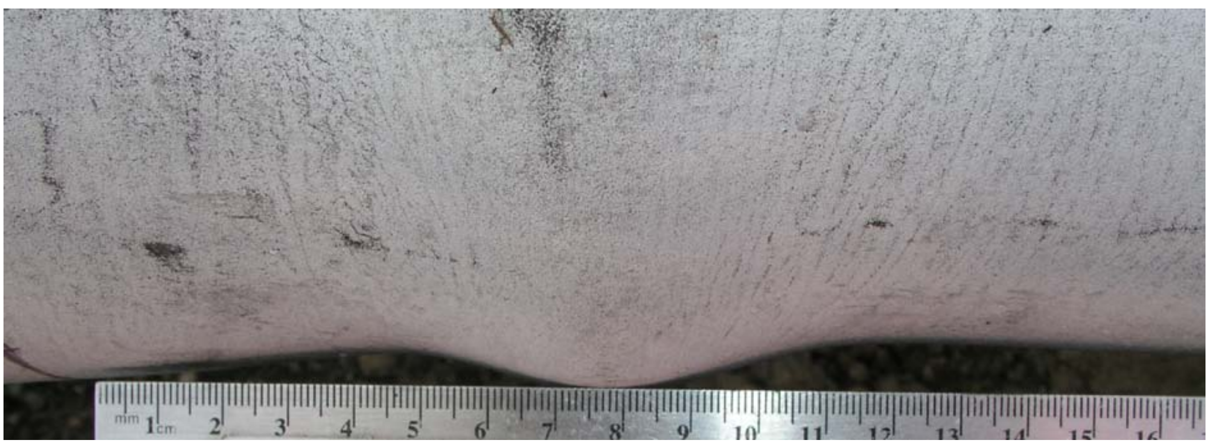


Figure 8: Pipeline Buckle

Figure 9: Pipeline Buckle with Crack

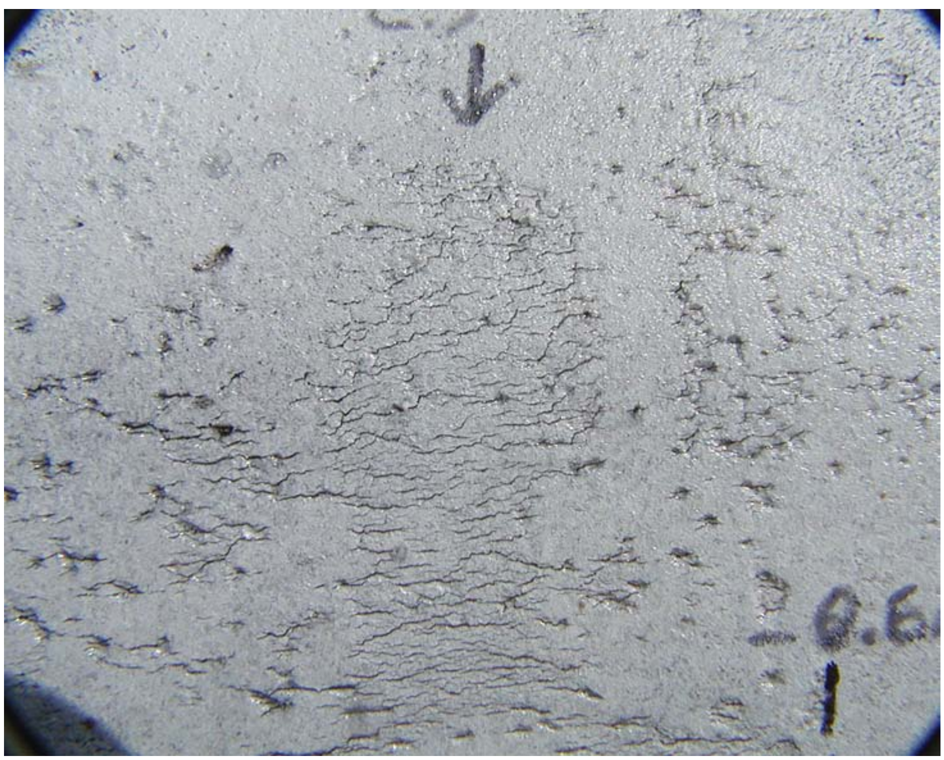


Figure 10: Stress Corrosion Cracking

Figure 11: Sliver

Appendix H
Test Stations, Bonds, and Cable to Pipe Connections

Test Stations, Bonds, and Cable to Pipe Connections

1.0 Test Stations

Test stations for electrical measurements shall be provided at intervals along the pipeline where a connection to the pipeline can not otherwise be made such as to an above ground pipeline appurtenance. A suggested spacing is 1.5 to 3.0 kilometers to the nearest road or access point. Two wires are to be installed to the Pembina pipeline at each location.

Test stations shall also be installed at bonds, road or railroad cased crossings, underground isolating fittings and pipeline crossings where practical. Two wires are to be installed to each foreign structure in addition to two wires to the Pembina pipeline. An exception can be made if there are multiple structures that are electrically continuous in which case only two wires to one point on the structure are required.

2.0 Bonds

Bonds may be installed to provide electrical continuity throughout the system or for stray current interference mitigation. In these cases the bond is considered as a critical bond which must be inspected bimonthly (every two months). Two wires to each side are required with one bond wire to each side for current and the other wire to each side to measure potentials.

3.0 Cable to Pipe Connections

Attachments of wires or cables to the pipe shall be made in such a way that they remain mechanically secure and electrically conductive without causing harmful effects to the pipe.

The thermite welding process or mechanical means may be used to attach copper electrical conductors directly to pressurized or non-pressurized pipe having a wall thickness of 2.8 mm or greater; however, for wall thicknesses in the range of 2.8 to 3.8 mm consideration must be given avoiding burn-through and undesirable microstructures.

The thermite weld is a preferred connection over a mechanical connection especially for a current carrying conductor.

Other methods such as brazing that involve the application of heat directly onto the pipe shall not be used to attach electrical wires.

Before applying a thermite weld, the pipe shall be inspected by an ultrasonic test to confirm that the wall thickness is the original pipe wall thickness and as specified above and that it is free of imperfections that would adversely affect the weld. Where the original pipe wall thickness or the thickness specified above does not exist, an engineering evaluation must be completed before a thermite weld is applied to confirm that it is safe.

Thermite welding shall be carried out by qualified persons and consideration shall be given to the following:

- Equipment manufacturers and suppliers instructions, recommendations, and safety advice;

- Safe working pressures;

- Location of the thermite welds relative to girth welds, seam welds, and other thermite welds; and

- Wire placement practices to minimize wire stresses during backfilling.

When attaching a cable or wire to the pipe, it should be wrapped around the pipe with a half-hitch or secured in such a manner as to take any stress off of the pipe connection.

The charge used in thermite welding shall be a specially designed, low-temperature aluminum and copper oxide powder mixture and shall not exceed 15 grams in mass.

Where a conductor larger than AWG No. 6 is required, a multi-strand conductor shall be used and the strands separated into groups no larger than the equivalent of an AWG No. 6 conductor. Each group shall then be separated (into a crow-foot) and thermite welded to the pipe with a separate 15 gram charge. Alternately the larger cable can be spliced to the center of a short section of AWG No. 6 cable and each end of the AWG No. 6 cable thermite welded to the pipe. The splice shall be made waterproof as described below.

Where the preferred thermite weld can not be safely applied, a mechanical cable to pipe connection can be considered. Where possible a mechanical connection is to be made above ground. There are two general types of connections including a flange lug type and a clamp-on type.

The flange lug type has a lug for the flange stud (bolt) that is welded to a conduit box with the cable lug attached inside the box. The cable is brought into the box through a conduit from a point 450 mm below ground. The flange face is cleaned to a bright finish and the lug is placed over the stud and securely attached with the nut.

The clamp-on type is designed to go around the pipe with provision for a cable connection to the clamp. The clamp is tightened to the pipeline with a bolt(s). Prior to installation, heavier coatings shall be removed around the pipe. The pipe to clamp contact point shall be cleaned to a bright finish. The secured cable is then attached to the lug provided in the clamp. Straps are to be avoided as they do not have a cable lug and they can stretch and loosen with time. Note that a rectifier negative cable carrying current with a loose cable to pipe connection and water underneath will cause corrosion on the pipe.

Where wires are connected to more than one pipeline or structure, the test lead wires shall be identified by a permanent label or color coded.

(a) Cable Burial

The direct burial cable is to be installed at a minimum depth of 600 mm and shall be laid free of insulation damage with slack to follow the contour of the ditch. The wire or cable is to be continuous and free of splices. Care is to be taken in backfilling cable to ensure that rocks do not damage the cable insulation. Polyethylene (yellow) warning tape shall be placed above direct buried cable runs that carry current, 300 mm below final grade. The cable is to enter into a test station or a junction box through a conduit.

(b) Cable to Structure Installation

The excavation of all buried structures shall be by hand or by a hydro-vac prior to any excavating machine being brought on location. Where such excavations exceed 1.2 meters in depth or where unstable soil conditions dictate, the sides shall be sloped or shored as per government regulations prior to entry. Ladders securely fastened and extending a meter above ground shall be used for access to the ditch.

Where a buried structure is to be crossed without exposure (after permission of the foreign owner), the cable ditch must be dug by hand for a distance of 10 meters on either side of the structure or at the distance required by the foreign owner.

All exposed metal surfaces shall be liberally coated with a suitable cold applied mastic and covered with either a tar felt paper, plastic cap or equivalent.

(c) Thermite Weld Procedure

Proper personnel protective clothing including hard hat, eye protection, gloves and fire retardant coveralls are to be worn. The fusion weld procedure to be followed is outlined below:

1. Test the weld area for explosive or combustible materials before welding.
2. Locate welds 50 mm minimum from pipe welds including the ERW seam.
3. Test the wall thickness with an ultrasonic test.
4. Remove coating and/or paint for an area that is slightly larger than the mold.
5. Wire brush and file exposed metal to a bright metal finish.
6. Wrap wire around pipe with a half-hitch or secure and remove insulation from end of the wire. If required attach a copper sleeve.
7. Test the mold with cable on pipe to ensure that it seats properly.

8. Insert the steel disk into the mold and empty the 15 gram cartridge into mold by quickly inverting it to ensure that the starting powder does not mix and remains on top. If moisture enters the powder, do not ignite as the steam that will be generated will blow the molten material out of the mold.

9. Seat the mold and ignite making sure that all persons are away from or protected from the flash.

10. If using a cartridge that comes complete and does not require the procedure in (8) & (9), place cartridge in mold in accordance to the manufacturer's instructions.

11. Ignite the cartridge.

12. Should the weld fail, a new location shall be found at least 50 mm from the previous attempt.

13. Clean the slag and allow it to cool.

14. Apply a mastic compound or cap and cover the area with a pipeline tape ensuring that no moisture can enter the weld area.

(d) <u>Cable Splice Connections</u>

Avoid underground cable connections and/or splices but if required the following practice is to be followed.

A minimum amount of insulation is to be removed without damage to the cable conductor ensuring sufficient space for the cables and connector only. The cables are to be connected using either a split bolt or crimped connector, sized for the cables being spliced and installed in the manner recommended by the manufacturer.

1. Apply successive layers of 19 mm width half lapped rubber tape splicing compound, to a minimum thickness equal to that of the original insulation.

2. Apply three layers of 19 mm width half lapped Scotch#33 electrical tape or equal to extend 25 mm beyond the rubber compound.

3. In rocky soil conditions, apply two layers of 19 mm width half lapped friction tape to cover the electrical tape.

Appendix I
Composite Repair Information

Figure 1: Example of a Magnet for Marking Composite Repairs
Source: http://www.kjmagnetics.com/

Appendix J
Forms

Index:

1. Ditch Profile Report
2. General Excavation Report
3. Coating Data Sheet
4. Corrosion Deposit Information Sheet
5. Metal Loss Correlation Report
6. Corrosion Depth Data Sheet
7. Deformation Report
8. Gouge and Arc Burn Report
9. MPI Report
10. Recoat and Repair Report

The forms are intended to be filled out electronically as many calculations and graphing are automated.

Form 1 - Ditch Profile Report

The Ditch Profile Report details the following:

a) General excavation information:
   i. Excavation ID#
   ii. Date
   iii. Inspector
b) Soil Profile (alongside diagram)
   i. Depth and type of each soil (i.e., 3 cm topsoil, 2 m lacustrine soil),
   ii. Depth of the water table
   iii. Depth of mottling or gleying
c) Profile diagram detailing the pipe inspected (shaded) with the flow direction shown,
   i. Place location of girth weld (if exposed) on diagram (detail reference weld)
   ii. Place previous repairs (i.e., weld sleeve, clockspring) on diagram
d) Overall Ditch Profile,
   i. Depth of cover (distance from topside of pipe to surface)
   ii. Ditch dimensions (length, width, and depth)
   iii. Exposed pipe length – length of entire exposed pipe and length from U/S weld (reference weld) to U/S end of ditch and D/S (downstream) end of ditch
e) Inspected Section of Pipe, and
   i. Length of entire inspected section of pipe, length of recoat, and distance from reference weld to the D/S and U/S end of recoat
   ii. Total length of recoated pipe
   iii. Centre location (distance from reference weld)
   iv. Type of repair and total length of repair
f) Additional Comments

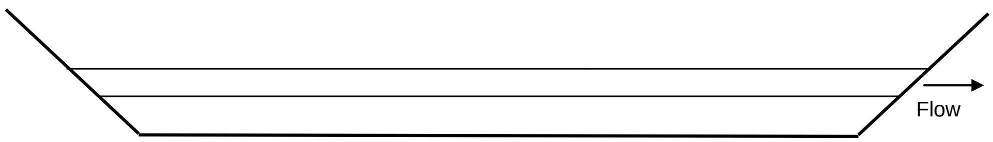
Sketches or details (if required) to clarify any details above

Ditch Profile Report

Excavation ID ____________
Date ____________
Inspector ____________

Identify locations of welds, bends, fixtures, and repairs on sketch

Soil layer type & depth



The ?/S Weld was used as the reference weld

Overall Ditch Profile	**Meters (m)**
Depth of cover	
Length of ditch	
Width of ditch	
Depth of ditch	
Depth of water table	
Depth of mottling	
Depth of gleying	
Length of exposed pipe	0.00
Distance from the reference weld to the U/S end of pipe	
Distance from the reference weld to the D/S end of pipe	

Section #1	
Length of investigated pipe	0.00
Length of recoat	0.00
Distance from the reference weld to U/S end of recoat	
Distance from the reference weld to D/S end of recoat	
Center line of repair from weld	0.00
Length of repair	
Type of repair	

Section #2	
Length of investigated pipe	0.00
Length of recoat	0.00
Distance from the reference weld to U/S end of recoat	
Distance from the reference weld to D/S end of recoat	
Center line of repair from weld	0.00
Length of repair	
Type of repair	

Comments:

Figure J.1 Ditch Profile Report

Ditch Profile Report

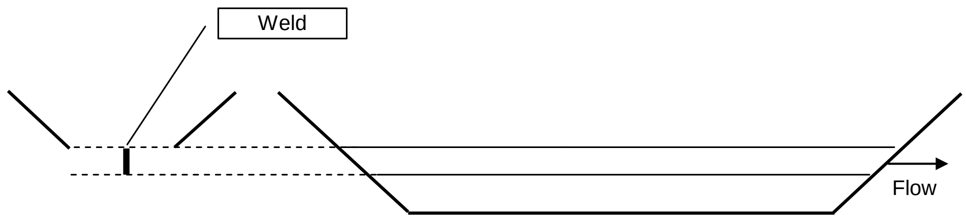
Excavation ID ______

Date ______

Inspector ______

Identify locations of welds, bends, fixtures, and repairs on sketch

Soil layer type & depth



The U/S Weld was used as the reference weld

Overall Ditch Profile	**Meters (m)**
Depth of cover	
Length of ditch	
Width of ditch	
Depth of ditch	
Depth of water table	
Depth of mottling	
Depth of gleying	
Length of exposed pipe	0.00
Distance from the reference weld to the U/S end of pipe	
Distance from the reference weld to the D/S end of pipe	

Section #1	
Length of investigated pipe	0.00
Length of recoat	0.00
Distance from the reference weld to U/S end of recoat	
Distance from the reference weld to D/S end of recoat	
Center line of repair from weld	0.00
Length of repair	
Type of repair	

Section #2	
Length of investigated pipe	0.00
Length of recoat	0.00
Distance from the reference weld to U/S end of recoat	
Distance from the reference weld to D/S end of recoat	
Center line of repair from weld	0.00
Length of repair	
Type of repair	

Comments:

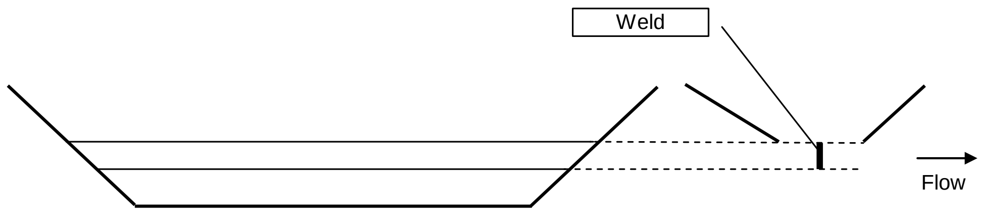
Figure J.2 Ditch Profile Report

Ditch Profile Report

Excavation ID ____
Date ____
Inspector ____

Identify locations of welds, bends, fixtures, and repairs on sketch

Soil layer type & depth



The D/S Weld was used as the reference weld

Overall Ditch Profile	**Meters (m)**
Depth of cover	
Length of ditch	
Width of ditch	
Depth of ditch	
Depth of water table	
Depth of mottling	
Depth of gleying	
Length of exposed pipe	0.00
Distance from the reference weld to the U/S end of pipe	
Distance from the reference weld to the D/S end of pipe	

Section #1	
Length of investigated pipe	0.00
Length of recoat	0.00
Distance from the reference weld to U/S end of recoat	
Distance from the reference weld to D/S end of recoat	
Center line of repair from weld	0.00
Length of repair	
Type of repair	

Section #2	
Length of investigated pipe	0.00
Length of recoat	0.00
Distance from the reference weld to U/S end of recoat	
Distance from the reference weld to D/S end of recoat	
Center line of repair from weld	0.00
Length of repair	
Type of repair	

Comments:

Figure J.3 Ditch Profile Report

Form 2 - General Excavation Report

The General Excavation Report details the following:

a) General excavation information required:

   i. Excavation ID

   ii. Date

   iii. Inspector

   iv. Weld number

   v. Pipeline information

   vi. Company location information/land use

   vii. ILI inspection and location information

b) Topographical information of the excavation site includes:

   i. Topographical position (i.e., inclined, level, side slope)

   ii. Slope position (i.e., upper, lower, mid, crest)

   iii. Drainage (i.e., well, poor, very poor)

   iv. Vegetation located directly over the pipe and adjacent to the right-of-way (i.e., trees, grasses)

   v. Soil type or soil profile of the ditch

c) Current weather conditions

d) Coating conditions (as applicable)

   i. Type of coating (i.e., asphalt coal tar)

   ii. Bonding (well, poor) and location (i.e., 7:00 – 9:00)

   iii. Holidays and location (i.e. at feature location)

   iv. Embedded rocks and location

v. Soil Deposits (i.e., calcareous)

e) Electrolyte pH

i. Measurement(s) taken using litmus paper

ii. Location of the measurement (i.e., o'clock position and distance from upstream weld)

iii. Corrosion product at the location of the measurement (if applicable)

f) Joint information

i. Length of entire joint

ii. Nominal and as found pipe wall thickness

iii. O'clock position of the long seam weld(s)

PEMBINA

Excavation ID ____________
Joint Number ____________
Date ____________
Inspector ____________
Pipeline System ____________
Pipeline Region ____________

General Excavation Report

Legal Land Description	**MOP (kPa)**		**Coordinates for the U/S Girth Weld**		**ILI Vendor/Year:**
	Pipe Diameter (mm)		**GPS Coordinates**		
Physiographic Region	**Nom. Wall Thickness (mm)**		**Northing (m) or Latitude**		**Type of Inspection:**
	Grade (Mpa)		**Easting (m) or Longitude**		
Land Use	**Manufacturer**		**Height (m)**		
	Longseam Type		**Chainage**		**RGW Odometer**
	Year of Installation		**Class Location**		

Topographical	**Undulated**		**Ridged**		**Inclined**		**Depressed**		**Level**		**Side Slope**	
Slope Position	**Crest**		**Upper**		**Mid**		**Lower**		**Toe**		**Level**	
Drainage	**Well**		**Imperfectly**		**Poorly**		**Very poorly**		**VP / VP**			

Weather Condition	
Above Grd Vegetation	
Soil layer type and depth	
Contributing Factors i.e. visible salts, water table depth	
Comments	
Coating Type	
Coating Condition	

Soil Resistivity	Feet	Ohms	Ohms-cm	Feet	Ohms	Ohms-cm	Feet	Ohms	Ohms-cm	Feet	Ohms	Ohms-cm

Pipe-to-Soil in Ditch (-mV$_{CSE}$)	**Location U/S or D/S**	Dist. From Weld (m)	O'Clock	"OFF"	"ON"	O'Clock	"OFF"	"ON"	O'Clock	"OFF"	"ON"	O'Clock	"OFF"	"ON"
			12:00			3:00			6:00			9:00		

Pipe-to-Soil Potential at test stations (-mV$_{CSE}$)	**U/S Test Lead**	**"OFF"**	**"ON"**	**D/S Test Lead**	**"OFF"**	**"ON"**

Reading #	1	2	3	4	5	6	7	8	9	10	11	12	13
pH of Electrolyte													
Distance from Weld (m)													
Ref. Weld Used (U/S or D/S)													
Clock Position													
Sample (yes/no)													
Sample Description													

Year of ILI Inspection	
Year of Predicted Failure	
Reason for Excavation	
Backfill and Cleanup Witnessed?	

Joint #		**Joint Length (m)**			**Nominal W.T. (mm)**		**W.T. as Found (mm)**		**Longseam**	
Joint #		**Joint Length (m)**			**Nominal W.T. (mm)**		**W.T. as Found (mm)**		**Longseam**	

Figure J.4 Excavation Report

Form 3 - Coating Data Sheet

The coating data sheet details the following:

a) General excavation information:

   i. Excavation ID/Weld number (Refer to the ID or weld number provided by the in-line inspection vendor where applicable)

   ii. Date

   iii. Inspector

b) Distance from the U/S reference weld is noted along the first row of the grid. The layout of the grid will be dependant on the size of the exposed pipe,

c) The disbonded and/or holiday areas are in shaded format within the grid, including the pH measurement obtained at the areas (if applicable), and

d) Location of the long seam weld and/or girth weld are presented on the grid at the appropriate o’clock position and chainage location (as applicable).

PEMBINA

Coating Data Sheet

Excavation ID	0	Inspector	0
Date	0-Jan-1900	Disbondment	pH
Rock Damage		Coating holiday	pH
Coating Type		Patch Coating	
Patch Type			

Clock \ Distance	
12:00	
11:45	
11:30	
11:15	
11:00	
10:45	
10:30	
10:15	
10:00	
9:45	
9:30	
9:15	
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2:45	
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2:15	
2:00	
1:45	
1:30	
1:15	
1:00	
0:45	
0:30	
0:15	

Figure J.5 Coating Data Sheet

Form 4 - Corrosion Deposits Information Sheet

The coating data sheet details the following:

a) General excavation information:

   i. Excavation ID/Weld number (Refer to the ID or weld number provided by the in-line inspection vendor where applicable)

   ii. Date

   iii. Inspector

b) Distance from the U/S reference weld and o'clock position of the corrosion deposits, and

c) The colour, texture, and distribution of the corrosion deposits.

PEMBINA

Excavation ID ____________
Date ____________
Inspector ____________

Corrosion Deposit Information Sheet							
Corresponding Feature ID	Dist. From Weld (m)	Ref. Weld (U/S or D/S)	Clock Position	Colour	Texture	Distribution	Comments

Figure J.6 Corrosion Deposits Information Sheet

Form 5 - Metal Loss Correlation Report

The Field Measured/ILI Data Report details the following:

a) General excavation information:

   i. Excavation ID

   ii. Date

   iii. Inspector

   iv. Weld number

   v. Pipeline name

   vi. Pipe diameter

   vii. Nominal wall thickness

b) In-line inspection reported defects and the corresponding (if applicable) actual field corrosion measurements,

c) Notes and other Field Observations,

d) Nominal wall thickness, Diameter, Grade, MOP, and Class Location (required for the burst pressure calculations), and

e) Association of the metal loss to other features (i.e. deformation or crack related).

PEMBINA

Excavation ID: ______________
Date: ______________
Compliance Reviewed by: ______________
Field Inspector: ______________

MFL Vendor: Name																			**Field Measurements:** NDT Company Name														**Comparison of Field/Tool Data**	
ILI Identification	Compliance Criteria #	Joint Number	Chainage (m)	Distance from U/S Weld (m)	SMYS	MOP (kPa)	Wall Thickness (mm)	External/ Internal	Clock Position	Depth (% WT)	Length (mm)	Width (mm)	Anomaly Description	Associated with Deformation or Cracking?	RStreng 0.85dL Predicted Burst Pressure (kPa)	RStreng 0.85dL RPR (100% MOP or SMYS)	RStreng Effective Area Predicted Burst Pressure (kPa)	RStreng Effective Area RPR (100% MOP or SMYS)	Reference Weld	Distance from U/S Weld (m)	Wall Thickness (mm)	Clock Position	Depth as Found (% WT)	Depth as Found (mm)	Length as Found (mm)	Width as Found (mm)	Defect Description as Found	Associated Deformation or Cracking Type	Repair Type	RStreng 0.85dL Predicted Burst Pressure (kPa)	RStreng 0.85dL RPR (100% MOP or SMYS)	RStreng Effective Area Predicted Burst Pressure (kPa)	RStreng Effective Area RPR (100% MOP or SMYS)	Depth Difference Field - Tool (% WT)	Burst Pressure Difference Field - Tool (%)

Figure J.7 Metal Loss Correlation Data Sheet

Form 6 - Corrosion Depth Data Sheet

This form is to be completed if a feature fails the 0.85dL criteria or if further correlation is required to assess a feature(s).

a) General excavation and grid information:

   i. Excavation ID/Weld number

   ii. Date

   iii. Inspector

   iv. Nominal and measured pipe wall thickness

   v. Distance from U/S weld and o'clock position at the starting point (A1)

   vi. Corresponding field feature number

   vii. Size of grid (i.e. 12.5 mm)

   viii. Grid page number (i.e. 1 of 2, 2 of 2, etc. as applicable)

b) A grid corresponding to the one marked out on the pipe surface at the location of the feature.

PEMBINA

Corrosion Depth Data Sheet

Excavation ID ____________
Date ____________
Feature # ____________
Dist from Weld (m) ____________
Clock Position ____________

W.T. Nominal (mm) ____________
W.T. Measured (mm) ____________
Grid # ____ of ____
Grid Size (mm) ____________

Note: the numbers in red are the numbers that were used for the Effective Area Calculations.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z
1																										
2																										
3																										
4																										
5																										
6																										
7																										
8																										
9																										
10																										
11																										
12																										
13																										
14																										
15																										
16																										
17																										
18																										
19																										
20																										
21																										

All Measurements in (mm)

Factor of Safety: ____________
Predicted Burst Pressure (kPa): ____________
Maximum Pit Depth (mm): ____________

Comments:

Inspector: ____________________

Figure J.8 Corrosion Depth Data Sheet

Form 7 - Deformation Report

The Deformation Report details the following:

a) General excavation information:

   i. Excavation ID/Weld number

   ii. Date

   iii. Inspector

b) Deformation

   i. Distance from the reference weld

   ii. Dimensions (depth, length, and width)

   iii. O’clock position

c) Dent

   i. Dent size as a percentage of the outside diameter

   ii. Associated welds and features

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Excavation ID: ____________
Date: ____________
Compliance Reviewed by: ____________
Field Inspector: ____________

ILI Vendor: Name																			**Field Measurements:** NDT Company Name																		Comparison of Field/Tool Data
ILI Identification	Compliance Criteria #	Joint Number	Chainage (m)	Anomaly Description	Distance from U/S Weld (m)	Wall Thickness (mm)	Clock Position	Associated with weld?	Associated with Metal Loss or Cracking?	Depth (% OD)	Depth (mm)	Diameter Restriction (%)	Length (mm)	Width (mm)	Wrinkle Height (mm)	Nominal Diameter (mm)	Minimum Diameter (mm)	Maximum Diameter (mm)	Field Identification	Defect Description as Found	Associated Metal Loss or Cracking Type	Distance from U/S Weld (m)	Wall Thickness (mm)	Clock Position	Associated with weld?	Depth as Found (% OD)	Diameter Restriction (%)	Depth as Found (mm)	Length as Found (mm)	Width as Found (mm)	Nominal Diameter (mm)	Minimum Diameter (mm)	Maximum Diameter (mm)	Metal Loss or Crack Length (mm)	Metal Loss or Crack Depth (%)	Repair Type	Depth Difference Field - Tool (% or mm Depth)

Figure J.9 Deformation Report

Form 8 - Gouge and Arc Burn Report

The Gouge and Arc Burn Report details the following:

a) General excavation information:

   i. Excavation ID/Weld number

   ii. Date

   iii. Inspector

b) Distance from the reference weld,

c) Type of defect,

d) Dimensions (depth, length, and width),

e) O'clock position,

f) Associated metal loss/deformation features, and

g) If the feature was ground, the dimensions of the grind.

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Gouge and Arc Burn Report

Excavation ID ____________
Date ____________
Inspector ____________

Gouge and Arc Burn Report									
Distance from Reference Weld (m)	**Ref. Weld (U/S or D/S)**	**Clock Position**	**Type of Defect**	**Length (mm)**	**Width (mm)**	**Depth (mm)**	**Depth (% of pipe wall thickness)**	**Located in Feature #**	**Was Defect Removed?**

Comments:

Include any ground areas on the metal loss spreadsheet

Figure J.10 Gouge and Arc Burn Report

Form 9 - MPI Report

The Crack-Like Features Report details the following:

a) General excavation information:

   i. Excavation ID/Weld number

   ii. Date

   iii. Inspector

b) Type of indication and corresponding field ID (i.e. linear indication #1),

c) Distance from the reference weld,

d) Dimensions of the indication and presence of interlinking,

e) Associated metal loss/deformation features, and

f) If the feature was ground, the dimensions of the grind.

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MPI Method: ________

MPI Areas:	Girth Welds	Longseams	Disbonded Areas	Deformations	Mechanical Damage	Full Circumference

Excavation ID: ________________

Date: ________________

Compliance Reviewed by: ________________

Field Inspector: ________________

ILI Vendor: Name																	
ILI Identification	Compliance Criteria #	Joint Number	Chainage (m)	Distance from U/S Weld (m)	SMYS	MOP (kPa)	Wall Thickness (mm)	External/ Internal	Clock Position	Depth (%WT or mm)	Length (mm)	Interlink Length (mm)	Width (mm)	Weld or Base Material ?	Anomaly Description	Predicted Burst Pressure (kPa)	RPR (100% MOP or SMYS)

Field Measurements: NDT Company Name																					
Field Identification	Associated Feature Present (Type)	Distance from U/S Weld (m)	Wall Thickness (mm)	Clock Position	Depth of Corrosion (% WT or mm)	Depth of Indication after Corrosion (% WT or mm)	Total Depth (% WT or mm)	Depth Measurement Method	Overall Length (mm)	Average Crack Length (mm)	Maximum Crack Length (mm)	Interlink Length (mm)	Continuous Length (mm)	Width as Found (mm)	Defect Description as Found	Repair Type	Continuous Length after 1 mm Grind Depth (mm)	Was Indication Removed?	Remaining Wall Thickness after Grind (mm)	Predicted Burst Pressure (kPa)	RPR (100% MOP or SMYS)

Comparison of Field/Tool Data	
Depth Difference Field - Tool (% WT)	Burst Pressure Difference Field - Tool (%)

Figure J.11 MPI Report

Form 10 - Recoat and Repair Report

The Recoat and Repair Report details the following:

a) General excavation information:

    iv. Excavation ID/Weld number

    v. Date

    vi. Inspector

b) Start and end distances of recoat and repairs,

c) Blast medium and surface profile/finish, and

d) Replacement pipe wall thickness and grade for cutouts.

Excavation ID ____________
Date ____________
Inspector ____________

Recoat/Repair Report							
Start (m from RGW)	**End (m from RGW)**	**Length (m)**	**Blast Medium**	**Surface Profile (mils/μm)**	**Surface Finish**	**Recoat or Repair Type**	**Replacement Pipe Wall Thickness/Grade (for cutout)**

Figure J.12 Recoat and Repair Report