Remaining Strength of Corroded Pipe (RSTRENG)

Assessment Procedure
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Section 1   Focused on understanding and recognizing pipe defects to meet industry’s zero leak mandate

1.1. Why Pipelines Fail?

Leaks and ruptures are the primary modes of failure which result from flaw growth such as corrosion and stresses such as mechanical damage from 3rd part hits on a pipeline. This procedure will be primarily focusing on time dependent defects such as external and internal corrosion. However, it must be understand the interaction of other defects with corrosion cannot be ignored and must be considered when assessing the integrity of the pipe. Below are examples of flaw growth versus stresses.

<table>
<thead>
<tr>
<th>Flaw Growth</th>
<th>Stresses (Ductile, Brittle, Toughness Loading)</th>
</tr>
</thead>
<tbody>
<tr>
<td>External Corrosion</td>
<td>Mechanical Damage</td>
</tr>
<tr>
<td>Internal Corrosion</td>
<td>Pressure Increase and or changes</td>
</tr>
<tr>
<td>SCC</td>
<td>Pipe Movement</td>
</tr>
<tr>
<td>Erosion</td>
<td>Thermal</td>
</tr>
<tr>
<td>Fatigue</td>
<td></td>
</tr>
</tbody>
</table>

Note: The goal of this RSTRENG procedure is to manage pipeline facility assets effectively and to reduce risk to meet industry’s goal of zero leaks.

1.2. Locate & Define Coating Holidays and Pipe Defects

To assess the integrity of the line pipe in each covered segment is accomplished by applying one or more of the following methods depending on the threat(s) to which the covered segment is susceptible to risk exposure. It may be necessary to run one or all of the methods depending on the risks and pre-assessment analysis.

1.2.1 In Line Inspection (ILI)

• ILI tool(s) are capable of detecting corrosion as well as other threats to which the covered segment is susceptible in accordance with ASME/ANSI B31.8S, Section 6.2.

1.2.2 Pressure Test (Hydro)
1.2.3 Direct Assessment (DA)

- Direct Assessment is used to address threats of external corrosion, internal corrosion, and stress corrosion cracking in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §192.925, §192.927 or §192.929;

1.2.4 Other Technology

- The use technologies that have demonstrated an equivalent understanding of the condition of the line pipe. Guided Wave Testing (GWT) is one such technology which can be found in NACE SP Guided Wave Testing for Piping Applications.

1.3. Excavations/Direct Examinations

Direct examination steps are used to calibrate and validate the prioritization of survey indications and their severity. In addition, field verification of reported ILI, GWT, DA features must be done to help confirm:

1.3.1 Reported critical features
1.3.2 Tool performance

Reporting of critical repairs must meet today’s integrity/safety TVC requirements of being:

- Traceable
- Verifiable
- Complete

1.3.3 Direct Examination Step

Verification ILI runs, DA surveys or prioritization of excavations is biggest challenge for the operator. The following is a process for this step:

- Prioritization
- Scheduling the excavations
- Excavating
- Assessment of coating damage and corrosion defects
  - NACE SP0502
1.4. Site Analysis and Documentation

Industry standards, regulatory requirements and operator protocols must be followed to achieve consistency with data collection. Some of these standards include and not limited are as follows:

1. ASME B31.8, B31.3, etc.
2. API 579, 1169, 1163, etc.
3. NACE ILI, GWT, ECDA, ICDA, etc.

Field personnel assigned to dig verification need to be certified and have the OQ to use the equipment to measure the reported features. This is to reduce problems that have occurred where reported feature sizes are incorrectly measured in the field.

Pipeline documents and forms are required for the following steps:

1. Feature location identification
   a. ILI odometer readings from nearest weld
   b. Chainage from DA Surveys
   c. GPS
2. Use other sources of information such as:
   a. As-Built drawings
   b. Survey plots
   c. One calls data
3. Excavation starts/ends with reference girth weld identification
4. Description of terrain and other features
5. Description of coating type and condition
6. Characterization of corrosion and deposits
7. Pipe condition
   a. 2D Photos of pipe surface defects
   b. 3D Scans of individual defects and interaction
8. Pipe surface preparation type and condition
9. Assessments and measurement data

Pipeline regulations are very clear: the responsibility for the pipeline integrity rests with the pipeline operator. How does the operator meet requirements of TVC for an integrity management program?

- Traceable – Records are those which can be clearly linked to original information about a pipeline segment or facility.
- Verifiable – Records are those in which information is confirmed by other complementary, but separate, documentation.
- Complete – Records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking.

1.5. Corrosion Mapping Tools

There are many types of tools that are used in the pipeline industry to assess time dependent defects such as external or internal corrosion.

1.5.1 Non-destructive testing (NDT)

NDT is an analysis technique used to determine the state or function of a system by comparing a known input with a measured output, without the use of invasive approaches like disassembly or failure testing.

NDT also called ultrasonic testing (UT), an ultrasound transducer connected to a diagnostic machine is passed over the object being inspected. The transducer is typically separated from the test object by a couplant (such as oil) or by water, as in immersion testing.

There are two methods of receiving the ultrasound waveform, reflection and attenuation. In reflection (or pulse-echo) mode, the transducer performs both the sending and the receiving of the pulsed waves as the "sound" is reflected back to the device. Reflected ultrasound comes from an interface, such as the back wall of the object or from an imperfection within the object. The diagnostic machine displays these results in the form of a signal with an amplitude representing the intensity of the reflection and the distance, representing the arrival time of the reflection. In attenuation (or through-transmission) mode, a transmitter sends ultrasound through one surface, and a separate receiver detects the amount that has reached it on another surface after traveling through the medium.
1.5.2 Pit gauges (Manual)

Pit gauges are used to determine corrosion allowances for equipment wherever metal loss affects materials, such as pipeline, vessels, piping, storage tanks, oil country tubular goods, drill pipe, bottom hole assemblies, bridges and other structures. Various types are available for different applications, including the Flat Gage for basic evaluation and the Bridging Pit Gauge for evaluating large areas of weight loss corrosion.

**Bridging Pit Gauge** allows the Corrosion Inspector to Span over or Cantilever into Large Areas of Weight Loss Corrosion, to obtain accurate and consistent measurements, or cross sections, of Pit Depth.
Flat Pit Gage is the most universal tool to measure localized external pitting on pipe and vessel surfaces.

1.5.3 3D Structured Light Toolbox

The 3D Toolbox is a portable, field ruggedized system for measuring and analyzing metal loss and mechanical damage on tanks, vessels and pipes. The process is a simple, four (4) step approach to meet the stringent regulatory requirements of TVC (Traceable, Verifiable and Complete):

- Validate calibration
- Measure the 3D pipe features/defects using the 3D Camera
- Analyze the 3D features to identify features of interest
- Export data features for post processing and reporting
  - ASME B31.8 and ASME B31.8 Modified for dents analysis

System Components

- 3D Camera
- Power Supplies and Adopters
- Cables
- Panasonic Toughbook
- Monopod
- Accessories (Batteries, Backpacks, Tripods, Tractors, etc.)

3D Structured Light

- Measures surface defects (Length, Width and Depth – X, Y & Z)
• Uses the Pipeline (PL) Analysis Tool for most common subsurface or above surface defects including welds

• Calculates remaining strength of corroded pipe (Level 1 and 2)

• Calculates the % Depth and Stress Strain (Level 1 and 2)

• Produces Corrosion and Dent reports to meet regulatory requirements for TVC

1.5.4 Guided Wave Testing (GWT)

GWT is a NDT technique for assessing long runs of pipe for metal wall loss caused by either internal/external corrosion or erosion and cracking. This technique can be used on pipes in soil, underneath insulation, cased crossings, offshore risers, through wall areas, heat exchanger tubes, etc. A set of arrays which consist of transducer elements are used which behave like a conventional ultrasonic transducer operating in pulse-echo mode. The ring sends out a burst of ultrasonic guided waves and then listens to signals that are reflected back as with conventional NDT.

1.5.5 Magnetic Particle Inspection (MPI)

A nondestructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field. See also ASTM E 709.10
1.5.6 Dye penetrant inspection (DPI)

DPI is also called liquid penetrant inspection (LPI), is a widely applied and low-cost inspection method used to locate surface-breaking defects in all non-porous materials (metals, plastics, or ceramics). Penetrant may be applied to all non-ferrous materials, but for inspection of ferrous components magnetic-particle inspection is preferred for its subsurface detection capability. LPI is used to detect casting and forging defects, cracks, and leaks in new products, and fatigue cracks on in-service components.

1.6. Identify & Classify Indications

The first step is to locate, identify and classify indication from ILI, DA, GWT, etc. surveys as listed below in Table 1 Coating Holidays and Pipe Defects. The primary focus for procedure is corrosion; however, the user must be aware of cracks, mechanical damage and other threats that may impact the safe pressure calculations.
## Table 1 Coating Holidays and Pipe Defects

<table>
<thead>
<tr>
<th>Coating Failures</th>
<th>Corrosion</th>
<th>Cracks</th>
<th>Mechanical</th>
<th>Nature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Delamination</td>
<td>Pitting</td>
<td>SCC</td>
<td>Dents</td>
<td>Lightning</td>
</tr>
<tr>
<td>Disbondment</td>
<td>General</td>
<td>Hydrogen</td>
<td>Gouges</td>
<td>Subsidence/Earth Movement</td>
</tr>
<tr>
<td>Shielding</td>
<td>Selective Seam</td>
<td>Fatigue</td>
<td>Arc Burns</td>
<td>Flooding</td>
</tr>
<tr>
<td>Application</td>
<td>MIC</td>
<td>Weld Seam</td>
<td>Stresses</td>
<td>Earthquakes</td>
</tr>
</tbody>
</table>

### 1.6.1 Report Critical Features from ILI

Results of the in-line inspection primarily provides features (indications) of wall loss defects with some characterization (classification) of the defect. Screening of this information is required in order to determine the time frame for examination and evaluation.

Direct Examination consists of a variety of direct inspection techniques including visual inspection, inspections using NDE equipment and taking 3D Structured Light measurements in order to characterize the defect in verification bell holes where anomalies are detected. Once the defect is identified and classified, evaluation of the defect must be made in order to determine the appropriate mitigation actions.

### 1.6.2 ILI Tool Performance

The effectiveness of an in-line inspection depends on the accuracies of the inspection system and the philosophy used by the pipeline company in investigating reported defects. Most in-line inspection companies report minimum detection thresholds of 5 to 10 percent of the wall thickness; below this depth, defects are not reported. Above the detection threshold, detection reliability is assumed to be high, near or above 95 percent. Sizing accuracies are typically given as ±10 percent of the wall thickness with
80 percent confidence (i.e., four out of five defects are sized to within 10 percent of their actual depths). Somewhat lower sizing accuracies are often given for pit-like defects that are short or narrow. Investigation and repair strategies vary with each pipeline company. In most cases, a company will investigate (dig and examine) reported defects until the calculated failure pressure of the remaining defects is above an acceptable level, which is usually set as a percentage of the yield pressure or maximum allowable operating pressure (MAOP). For example, an operator may excavate and investigate reported defects until the calculated failure pressure of all remaining defects is at least 1.25 times the MAOP based on the reported defect geometries.

1.7. Prioritization of Indications

The strategy used by the pipeline company to investigate areas adjacent to reported defects also impacts the effectiveness of the in-line inspection. If the pipeline company automatically extends bell holes until there is no indication of damaged coating and/or no indications of corrosion, the effectiveness is increased. The effectiveness increases because the pipeline company discovers coating faults and metal-loss defects that may not have been located by the inspection run.

Consequently, the overall effectiveness of an in-line inspection depends on many factors, including the smart-pig accuracy, the pipeline company’s philosophy of investigating reported defects, and the pipeline company’s strategy for extending bell holes.

1.7.1 ILI Effectiveness

A representative effectiveness of an in-line inspection for comparison with other methods of assessing pipeline integrity can be calculated in a manner similar to that for a pressure test.

\[
\text{Remaining life} = \text{Growth fraction} \times \text{wall thickness} / \text{growth rate}
\]

Where, the growth fraction is determined for the reported defect with the smallest predicted failure pressure. Alternatively, statistical (probabilistic) analyses are possible using the reported defect distribution.

1.8. Data Requirements and Report Results

Below are the data requirements that must be documented in order to meet the TVC requirements for a direct examination:

- General Information
  - Project
  - Line name or ID
- Site Location
- Date
- Inspector’s name
- Contractor name
- ILI information
- **Description of Anomaly/Feature**
  - Wheel Count (WC)
  - Anomaly/Feature type
  - O’clock position
  - Length, width, depth
  - Upstream (U/S) reference i.e. weld description and WC
- **Location Information**
  - Alignment sheet number
  - Upstream engineering station number and U/S weld reference
  - Anomaly distance from U/S reference
- **Pipe Information**
  - Outside Diameter (OD)
  - Nominal wall thickness (WT)
  - Measured WT adjacent to anomaly
  - Seam type
- **Coating information**
  - Coating type
  - Coating condition
  - Holiday size
  - Shielding – high dielectric materials
- **Girth Welds and Pipe Seams**
  - Girth weld reference number
  - Long seam o’clock position
  - Joint length
- **Mechanical Damage - Dents**
  - Type (Characterization)
  - Distance from U/S girth weld
  - Length, width, depth, o’clock position
  - Remaining WT
  - Verification (3D Tools, NDE, etc.)
- **Metal Loss – Corrosion**
  - Type (Characterization)
  - Distance from U/S girth weld
  - Length, width, depth, o’clock position
  - Remaining WT
• Verification (3D Tools, NDE, etc.)
  • Planar Flaws – Cracks
    o Type (Characterization)
    o Distance from U/S girth weld
    o Length, width, depth, o'clock position
    o Remaining WT
    o Verification (3D Tools, NDE, etc.)
• Repair Information
  o Reduce Pressure
  o Repair
    ▪ Type B pressurized sleeve
    ▪ Type A reinforcing sleeve
    ▪ Composite reinforcing sleeve
    ▪ Direct weld metal deposition
    ▪ Leak clamp
    ▪ Grind or buff out
  o Replace Cylinder of Pipe
  o Reccoat
• Dig Site Sketch
  o Locations of reference welds and other features
  o ILI sheets
• Photos
  o 360 Degree topography
    ▪ Before excavation
    ▪ Excavation site
    ▪ Clean up
  o Exposed pipe
  o Anomalies
    ▪ Before cleaning
    ▪ After cleaning
    ▪ Identification marks with flow direction
  o Completed repair(s) and mitigation
• Documentation (Complete)
  o Written summary of all assessments, work performed and results

1.9. Mitigation and Repair

Defects discovered during initial inspections shall be addressed by a pipeline operators repair plan. These plans include the methods and timing of all repairs.
Operators are required to make repairs in accordance to a prioritized repair schedule established by considering the results of a risk assessment and the severity of conditions discovered in the pipeline. The required repair schedule interval begins at the time the condition is discovered such as an ILI run.

Defect repairs can be divided into three groups and repair intervals. Performance based repairs are determined by engineering critical assessments (ECAs).

<table>
<thead>
<tr>
<th>Repairs</th>
<th>Repair Interval</th>
</tr>
</thead>
<tbody>
<tr>
<td>Defects</td>
<td>Prescriptive</td>
</tr>
<tr>
<td>Immediate</td>
<td>5 days</td>
</tr>
<tr>
<td>Scheduled</td>
<td>2 – 5 years</td>
</tr>
<tr>
<td>Monitored</td>
<td>10 years</td>
</tr>
</tbody>
</table>

All repairs are made with materials and processes that are suitable for the pipeline operating conditions. Defect Repairs include the following practices:

- Reduce Pressure
- Repair
  - Type B pressurized sleeve
  - Type A reinforcing sleeve
  - Composite reinforcing sleeve
  - Direct weld metal deposition
  - Leak clamp
  - Grind or buff out
- Replace Cylinder of Pipe
- Recoat

**Section 2   Definitions**

The following are definitions of some key terms used:

**Active:** A state in which a metal is corroding without significant influence or shielding by the reaction product.

**Aerobic:** Oxygen-containing.

**Anaerobic:** Free of air or uncombined oxygen.
Anomaly: Any deviation from nominal conditions in the external wall of a pipe, its coating, or the electromagnetic conditions around the pipe.

Anode: The electrode of an electrochemical cell at which oxidation occurs. Electrons flow away from the anode in the external circuit. Corrosion usually occurs and metal ions enter the solution at the anode.

Aspect Ratio: Ratio of crack length to crack depth.

Asphalt Coating: Asphalt based anti-corrosion coating.


Categorization: The process of estimating the need for repair of each indirect inspection indication based on current corrosion activity plus the extent and severity of prior corrosion.

Cathode: The electrode of an electrochemical cell at which reduction is the principal reaction. Electrons flow toward the cathode in the external circuit.

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.

Class Location: A geographical area classified according to its population density and other characteristics that are considered when a pipeline is designed and pressure tested.

Classical SCC: A form of SCC on underground pipelines that is intergranular and typically branched and is associated with an alkaline electrolyte (pH about 9.3). Also referred to as high-pH SCC.

Classification: The process of estimating the likelihood of corrosion activity at an indirect inspection indication under typical year-round conditions.

Close interval survey (CIS): A method of measuring the potential between the pipe and earth at regular intervals along the pipeline.

Cluster: A grouping of stress corrosion cracks (colony). Typically stress corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area.

Coal Tar Coating: Coal tar-based anti-corrosion coating.
Colony: A grouping of stress corrosion cracks (cluster). Typically stress corrosion cracks occur in groups consisting of hundreds or thousands of cracks within a relatively confined area. See Cluster.

Collinear: Lying along the same line (coaxial). A term used to describe spatial relationship of adjacent cracks.

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

Corrosion activity: A state in which corrosion is active and ongoing at a rate that is sufficient to reduce the pressure carrying capacity of a pipe.

Corrosion Assessment Techniques:

**Level 1** assessments shall be limited to components with one-sided widespread pitting damage designed to a recognized code or standard using an equation that specifically relates pressure to a required wall thickness. The only load considered is internal pressure.

**Level 2** assessments can be used to evaluate components that do not meet Level 1 assessment criteria. The Level 2 Assessment procedures are used to evaluate all four categories of pitting: widespread pitting, localized pitting, pitting within a locally thin area, and a locally thin area in a region of widespread pitting. The Level 2 Assessment rules provide a better estimate of the structural integrity of a component because a measure of the actual damage parameter, the pit-couple, is directly used in the assessment. The Level 2 assessment should be used when the pitting damage occurs on both sides of the component. Level 3 assessments can be used to evaluate components that are not covered by, or do not pass a Level 1 or Level 2 Assessment.

**Level 3** Assessment procedures are intended to evaluate more complex regions of pitting, loading conditions, and/or components with details where only limited design rules are provided in the original construction.

Covered Segment: A segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in § 192.3.

Crack Coalescence: Joining of cracks that are in close proximity to form one larger crack.

Critical Flaw Size: The dimensions (length and depth) of a flaw that would fail at a given level of pressure or stress.

Defect: An anomaly in the pipe wall that reduces the pressure carrying capacity of the pipe.
Direct-current voltage gradient (DCVG): A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.

Direct examination: Inspections and measurements made on the pipe surface at excavations as part of ECDA.

Disbonded coating: Any loss of adhesion between the protective coating and a pipe surface as a result of adhesive failure, chemical attack, mechanical damage, hydrogen concentrations, etc. Disbonded coating may or may not be associated with a coating holiday. See also cathodic disbondment.

ECDA Region: A section or sections of a pipeline that has similar physical characteristics and operating history and in which the same indirect inspection tools are used.

Electrolyte: A chemical substance containing ions that migrate an electric field. For the purposes of this recommended practice, electrolyte refers to the soil or liquid adjacent to and in contact with a buried or submerged metallic piping system, including the moisture and other chemicals contained therein.

Electromagnetic inspection technique: An above ground survey technique used to locate coating defects on buried pipelines by measuring changes in the magnetic field that are caused by the defects.

External Corrosion Direct Assessment (ECDA): A four-step process that combines pre-assessment, indirect inspections, direct examinations, and post-assessment to evaluate the impact of external corrosion on the integrity of a pipeline.

Fatigue: The phenomenon leading to fracture of a material under repeated or fluctuating stresses having a maximum value less than the tensile strength of the material.

Ferrous material: A metal that consists mainly of iron. In this Recommended Practice, ferrous materials include steel, cast iron, or wrought iron.

Fracture Toughness: A measure of a material’s resistance to static or dynamic crack extension. A material’s property used in the calculation of critical flaw size for crack-like defects.

Girth Weld: The circumferential weld that joins two sections of pipe.

Gouge: A surface imperfection caused by mechanical damage that reduces the wall thickness of a pipe or component.

GTI: Gas Technology Institute
**High-pH SCC:** A form of SCC on underground pipelines that is intergranular and typically branched and is associated with an alkaline electrolyte (pH about 9.3). Also referred to as classical SCC.

**Holiday:** A discontinuity in a protective coating that exposes unprotected surface to the environment. This includes disbonded areas and laminations.

**Hoop Stress:** Circumferential stress in a pipe or pressure vessel that results from the internal pressure.

**Hydrostatic Testing:** Pressure testing of sections of a pipeline by filling it with water and pressurizing it until the nominal hoop stresses in the pipe reach a specified value.

**Immediate indication:** An indication that requires remediation or repair in a relatively short time span.

**Instruction:** A detailed sequence of steps to be followed to apply an NDE method of inspection.

**Interaction Rules:** According ASME B31.4¹ there are two type of Interaction Rules. *Type I Interaction*- If the circumferential separation distance, \( C \), is greater than or equal to 6 times the wall thickness required for design, the areas \( A_1 \) and \( A_2 \) should be evaluated as separate anomalies. If the circumferential separation distance is less than six times the wall thickness, the composite area \((A_1 + A_2 - A_3)\) and the overall length, \( L \), should be used. See figure 1 below.

![Figure 1](image)

(2) *Type II Interaction* If the axial separation distance, \( L_3 \), is greater than or equal to 1 in. (25.4 mm), the areas \( A_1 \) and \( A_2 \) should be evaluated as separate anomalies. If the axial separation distance is less than 1 in. (25.4 mm), area \( A_1 \) plus \( A_2 \) should be used and the length, \( L \), should be taken as \( L_1 + L_2 + L_3 \). See figure 2 below.

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¹ ASME - Two Park Avenue New York, NY 10016-5990
Indication: Any deviation from the norm as measured by an indirect inspection tool.

Indirect inspection: Equipment and practices used to take measurements at ground surface above or near a pipeline to locate or characterize corrosion activity, coating holidays, or other anomalies.

In-Line Inspection (ILI): The inspection of a pipeline from the interior of the pipe using an ILI tool. These tools are known as pigs or smart pigs also called intelligent or smart pigging.

ILI Tool: An instrumented device or vehicle that uses a nondestructive testing technique to inspect the pipeline from the inside or that uses sensors and other equipment to measure one or more characteristics of the pipeline. Also known as intelligent or smart pig.

Intergranular Cracking: Cracking in which the crack path is between the grains in a metal (typically associated with high-pH SCC).

Instant “OFF” potential: A measurement of a pipe to electrolyte potential made without perceptible delay following the interruption of cathodic protection.

Investigative Dig: An inspection of a pipeline at a discrete location exposed for examination.

Leak: Product loss through a small hole or crack in the pipeline.

Low-pH SCC: A form of SCC on underground pipelines that is transgranular and is associated with a near neutral-pH electrolyte. Typically this form of cracking has limited branching and is associated with some corrosion of the pipe surface. Also referred to as near-neutral-pH or non-classical SCC.

Magnetic Particle Inspection (MPI): A nondestructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field. See also ASTM E 709.10.

Maximum Allowable Operating Pressure (MAOP): the maximum internal pressure permitted during the operation of a pipeline.
Mechanical Damage is a type of anomaly in a pipe caused by the application of an external force. Mechanical damage can include denting, coating removal, metal removal, metal movement, cold working of the underlying metal, and residual stresses, any one of which can be detrimental.

**Metallography:** The study of the structure and constitution of a metal as revealed by a microscope.

**Microbiologically induced or influenced corrosion (MIC):** A form of accelerated corrosion that results from certain microbes and nutrients in the soil.

**Monitored indication:** An indication that is less significant than scheduled and which does not need to be addressed or require remediation or repair before the next scheduled re-assessment of a pipeline segment.

**Near-Neutral-pH SCC:** A form of SCC on underground pipelines that is transgranular and is associated with a near-neutral-pH electrolyte. Typically this form of cracking has limited branching and is associated with some corrosion of the crack walls and sometimes of the pipe surface. Also referred to as low-pH or nonclassical SCC.

**Operator Qualification (OQ)** is a regulated covered task on a pipeline facility identified by a pipeline operator that is performed on that facility, is an operation or maintenance task, is a regulatory requirement and affects the operation or integrity of the pipeline.

**Pipe to electrolyte potential:** The potential difference between the pipe metallic surface and the electrolyte that is measured with reference to an electrode in contact with the electrolyte. This measurement is commonly termed pipe-to-soil.

**Polarization:** The change from the open-circuit potential as a result of current across the electrode/electrolyte interface.

**Potential Impact Circle:** A circle of radius equal to the potential impact radius (PIR).

**Potential Impact Radius (PIR):** The radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula \( r = 0.69 \times (\text{square root of } (p \times d^2)) \), where \( r \) is the radius of a circular area in feet surrounding the point of failure, \( p \) is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and \( d \) is the nominal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use Section 3.2 of ASME/ANSI B31.8S to calculate the impact radius formula.
**Remediation:** Repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

**Residual Stress:** The locked-in stress present in an object that results from the manufacturing process, heat treatment, or mechanical working of the material.

**RSTRENG:** An industry approved program designed to calculate the safe pressure carrying capacity of corroded pipe (see references PHMSA, PRCI, ASME).

**Rupture:** A failure of a pipeline that results from fracture propagation and causes an uncontrolled release of the contained product.

**Scheduled indication:** An indication that is less significant than immediate but which is to be addressed before the next scheduled reassessment of a pipeline segment.

**Segment:** A portion of a pipeline that is (to be) assessed.

**Shielding:** Preventing or diverting the cathodic protection current from its intended path to the structure to be protected.

**SCC:** An SCC cluster is assessed was defined to be “significant” by the Canadian Energy Pipeline Association (CEPA) (3) in 1997 provided that the deepest crack, in a series of interacting cracks, is greater than 10% of the wall thickness and the total interacting length of the cracks is equal to or greater than 75% of the critical length of a 50% through-wall flaw that would fail at a stress level of 110% of SMYS. CEPA also defines the interaction criteria. The presence of extensive and “significant” SCC typically triggers an SCC mitigation program (See discussion under Post-Assessment Step), but a crack that is labeled “significant” is not necessarily an immediate threat to the integrity of the pipeline.

**Sound engineering practice:** Reasoning exhibited or based on thorough knowledge and experience, logically valid and having technically correct premises that demonstrate good judgment or sense in the application of science.

**Specified Minimum Yield Strength (SMYS):** The minimum yield strength of a material prescribed by the specification or standard to which the material is manufactured.

**Stray current:** Current through paths other than the intended circuit.

**Stress Corrosion Cracking (SCC):** Cracking of a material produced by the combined action of corrosion and tensile stress (residual or applied).

**Stress Corrosion Cracking Direct Assessment SCCDA:** The stress corrosion cracking direct assessment process.
Subcritical Crack: A crack that is not large enough to cause spontaneous failure at a specific pressure or stress.

Structure-to-Electrolyte Potential: The potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

Subcritical Crack: A crack that is not large enough to cause spontaneous failure at a specific pressure or stress.

Tensile Stress: Stress that tends to elongate the material.

Tenting: A tent-shaped void formed along the seam weld of a pipeline where the external tape coating bridges from the top of the weld to the pipe.

Terrain Conditions: Collective term used to describe soil type, drainage, and topography. Often used as input in the generation of SCC predictive models.

Transgranular Cracking: Cracking in which the crack path is through the grains of a metal (typically associated with near-neutral-pH SCC).

Voltage: An electromotive force or a difference in electrode potentials, commonly expressed in volts.

Yield Strength: The stress at which a material exhibits a specified deviation from the proportionality of stress to strain. The deviation is expressed in terms of strain by either the offset method (usually at a strain of 0.2%) or the total-extension-under-load-method (usually at a strain of 0.5%).

Section 3 Technologies Used for Assessing Pipeline Defect

3.1. Types of Corrosion Measurements

Factors for selecting a Level for analysis of a corroded area include quantity and quality of data available with which to perform an evaluation. The least understood issue in making corrosion assessments include:

- Type of tools to accurately measure corrosion pitting
  - Common Field Type Gauges
    - Flat pit gauge
    - Spanning or bridging pit gauge
  - 3D Technologies
    - Structured Light
- Laser
  - Pipe preparation
    - Remove Coating
    - Abrasive blast clean pipe to remove all scale and deposit
    - Establish Grids and Points of Reference
    - Visually Inspect for Other Defects
  - Training and certification of individuals making these assessments
    - NACE
    - ASNT
    - OQ
  - Documentation

3.1.1 Common Field Type Mechanical Pit Gauges

The two (2) common type of mechanical pit gauges for measuring corrosion pitting on pipes are the flat and the bridging or spanning types. The flat pit gauge has been around at least 70 years doing Level 1 type pitting investigations for maximum depth and length on a single pit. However, for Level 2 evaluations which requires more detailed pit depths and accuracies, new technologies such as the 3D tools are now needed.

- Time to Assess
  - Slow and Methodical Process
- Error
  - Common Field Measurements can Vary from +-10%
  - Dependent on Technicians Abilities
  - Error prone in every step
- Impact on corrosion analysis
  - Safety
  - Unnecessary cut outs
  - Economic
3.1.2 3D Tools to Assess Defects

There are two (2) basic type of 3D tools to measure corrosion pitting and other defects. 3D structured light and laser are the most common methods used.

With the advances 3D structured light also known as Phase Measurement Profilometry (PMP), this has changed the dynamics of the industry. Combining this technology with advanced software using statistical analysis has produced better pipeline integrity predictions to meet the demands of safely transporting today's energy products. Because of the limitations of the other pitting tools and methods, the 3D structured light approach offers the following benefits:

- Meets IP67 requirements (Can be dropped on concrete and or submerged/used underwater)
- Repeatability (Measure of performance each time)
- Speed - Takes photos similar to a 2D camera in less than 80 milliseconds (mS)
- Visual and digital records are produced immediately for assessment to meet regulatory requirements
- Immediate data is made available for assessments using ASME B31G, Modified ASME B31G, RSTRENG©, API 579/ASME FFS-1, statistical calculations and stress strain calculations for dents
- Internal error checking - on every pixel
- Accuracy – Less than 50.8 microns (2 mils)

3.2. ASME/API 579 FFS-1 (Level 1, 2 and 3)
Fitness for service has been used in the oil and gas industry since the early 1980’s. On the petroleum industry side, it was always known as FFS, while on the gas pipeline side, it was known as ASME B31.G. In 2007 the American Petroleum Institute (API) and American Society of Mechanical Engineers (ASME) published a joint document as API RP 579-1/ASME FFS-1. This recommended practice (RP) consists of the following three levels for assessing corrosion:

- **Level 1** – Quick evaluation with the minimum number of measurements (maximum depth and length) with a built in large safety factor (ASME B31.G and Modified B31.G).
- **Level 2** – Additional measurements and more in-depth analysis to establish a remaining strength of corroded pipe (RSTRENG).
- **Level 3** – Intensive measurements using tools such as the 3D Toolbox - Phase Measurement Profilometry (PMP), loading, stresses, stress strain and material understanding to conduct a finite element analysis (FEA).

Because of the errors in the past using mechanical instrumentation (pit gauges) used in the past, rarely was a Level 3 analysis conducted. The field data was too inconsistent or too difficult to measure due to the complexity of the defects and features. Factors for selecting a Level for analysis of a corroded area include:

- Quantity of data available with which to perform an evaluation
- Quality of the data
- Degree of significance of the analysis to the pipeline operations
- Degree of significance of a specific corroded area in the remedial plan for all anomalies in a line section being investigated

### 3.3. Pit Gage Measurements

#### 3.3.1 Pitting and Corrosion (Traceable)

**Inspection problem:** Pitting on a regulated pipeline must be assessed by a trained, certified and operator qualified person. If the pitting is assessed to be severe, the pipe may need to be repaired or replaced as a cylinder. Identifying these areas of concern to the operator’s records where they do not meet industry standards requires training not only field pitting measurements, but also in understanding of ASME B31.G, Modified B31.G and RSTRENG assessments.

#### 3.3.2 Requirements (Verifiable)

**Measurements** - The depth(s) of pitting must be measured and verified by a qualified person who has training and certification for this task on a regulated pipeline operation.
If these field measurements cannot be verified, then the operator has no way to measure their performance at the beginning of their integrity program and periodically evaluate the results of these measures to monitor and evaluate the effectiveness of the program.

New technologies such as 3D Structured Light can improve an operator's ability to prevent certain types of failures, detect threats more effectively or improve the mitigation of these threats. Pipeline operators should avail themselves of these technologies as they become proven and practical in the field.

### 3.3.3 Assessments (Complete)

RSTRENG, B31G and Modified B31.G are industry approved programs designed to calculate the safe operating pressures of corroded pipe for complete documentation. Training with certification are required to understand when and how to use these programs. The operator must understand these limitations, interaction of pitting, other defects, materials, as well as stresses that could negate the results of these programs.

### 3.4. Industry Desires

New technologies should be evaluated and implemented as appropriate when older technologies are no longer meeting the safety and regulatory needs.

In order to meet the requirements of TVC, traceable, verifiable and complete in determining the effectiveness of an operator's integrity management program, new technologies should be evaluated in order to continuously improve the integrity management program.

#### 3.4.1 Significant opportunities for improvement using 3D Structured Light

- Reduce or eliminate human factors from measurement process
  - Simple to use
- Increase speed
- Reduce cost
- Shorten time from examination to decision
- Enhanced analysis solutions
  - Exportable/useable data
- Permanent Reporting & Documentation
Data collection to FFS answer in very short time

3.5. 3D Analysis Approach

The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered. A performance based program through appropriate evaluation and analysis is used to determine courses of action and time frames for the application of the inspection tools. It is the responsibility of the operator to document the analyses justifying the alternate courses of action or time frames.

Data and information from an inspection run for a specific threat is valuable when considering the presence of other threats. Example: a dent may be identified when ILI is run while assessing for corrosion. These threats should be integrated with other threats. Below is a listing of various threats that are found on pipelines.

- Arc Strike
- Artificial Defect
- Buckle
- Corrosion
- Corrosion Cluster
- Cracks -Visible
- Dent
- Dent With Metal Loss
- Gouging
- Grinding
- Girth Weld Crack
- Girth Weld Anomaly
- Hydrogen Induced Cracking
- Longitudinal Weld Crack
- Longitudinal Weld Pipe Mill Anomaly
- Pipe Mill Anomaly Cluster
- Stress Corrosion Cracking (SCC)
- Spiral Weld Crack
- Spiral Weld Anomaly
• Wrinkles

After the initial assessments have been performed, the operator needs to update information about the condition of the pipeline system or segment. This information is part of the TVC process and needs to be part of the database of information used to support integrity evaluations.

3.6. Examples of 3D Structure Light Measurements

3.6.1 3D Toolbox

The 3D Toolbox is a portable, field ruggedized system for measuring and analyzing metal loss and mechanical damage on tanks, vessels and pipes. The process is a simple, four (4) step approach to meet the stringent regulatory requirements of TVC (Traceable, Verifiable and Complete):

• Validate calibration
• Measure the 3D pipe features/defects using the 3D Camera
• Analyze the 3D features to identify features of interest
• Export data features for post processing and reporting
  o ASME B31.8 and ASME B31.8 Modified for dents analysis

3.6.2 System Components

• 3D Camera
• Power Supplies and Adopters
• Cables
• Panasonic Toughbook
• Monopod
• Accessories (Batteries, Backpacks, Tripods, Tractors, etc.)

3.6.3 3D Structured Light Toolbox

• Measures surface defects (Length, Width and Depth – X, Y & Z)
• Uses the Pipeline (PL) Analysis Tool for most common subsurface or above surface defects including welds
• Calculates remaining strength of corroded pipe (Level 1 and 2)
• Calculates the % Depth and Stress Strain (Level 1 and 2)
• Produces Corrosion and Dent reports to meet regulatory requirements for TVC

Below is a technician taking 3D scans of external corrosion in the Algerian Desert. 3D Structured Light can be used in variety of ambient light conditions from ambient light to inside tanks or vessels.

Section 4 Evaluation the Remaining Strength of Corroded Pipe


The initial procedure for evaluating remaining strength was developed after pressuring actual corroded pipe to failure. Several hundred, full-size, full-scale tests using actual field pipe specimens of all types of defects were completed. Basic metallurgical principles presumed at the start of the tests were that resistance to fracture is related to the size of the defect and metal property toughness. The larger the corroded area the lower the failure pressure. The tougher the steel the larger the defect that can be tolerated.

4.1.1 Barlow’s Formula

For U.S. gas and hazardous liquid pipelines the formula for predicting the pressure that may cause an area of the pipe wall to yield is known as Barlow’s formula:

\[ P = \frac{2t(\text{SMYS})}{D} \]
4.1.2 MAOP (Maximum Allowable Operating Pressure)

For safety reasons a maximum allowable operating pressure (MAOP) is set lower than the calculated yield pressure by a percent referred to as the Design Factor (F) known as:
- 0.72% (Basis for Corrosion Calculations with Hazardous Liquid Lines)

As allowable operating pressures are based on nominal wall thicknesses for full lengths of a pipeline segment a prime question asked is: What pressure can be calculated and recognized as safe for random areas of pipe wall found with reduced thickness caused by corrosion?
- A viable calculation providing the lowest estimated pressure that will cause the area to fail/burst
- A decision of what maximum pressure lower than the fail pressure would be safe for operations


Application of B31.G limited to:
- Corrosion on weldable pipeline steels
- Corrosion with smooth contours (Blunt Defects)
- Corrosion in isolated areas

Excluded are:
- Corrosion in welds or grooves
- Mechanical damage (Stresses)

Objective to evaluate structural integrity:
- Internal Pressure (Barlow’s Formula)
- Not secondary stresses

4.1.4 Basic Equation for Hoop Failure Stress

\[ S_f = S \left(1 - \frac{A}{A_0}\right) \left(1 - (\frac{A}{A_0})^M\right) \]

- \( S \) = Flow stress; the level of stress beyond yield before the pipe metal will fail
- \( A \) = Area of metal loss in a projected longitudinal profile of the defect
- \( A_0 \) = Total affected area of the pipe wall in the profiled longitudinal plane
- \( M \) is the Folias Factor, a factor which accounts for stress amplification at the ends of a flaw resulting from radial deflections along the flaw
4.2. References in DOT 192.485c, 195.585 & 195.587

4.2.1 192.933 What actions must be taken to address integrity issues?

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

4.2.2 192.485 Remedial measures: Transmission Lines

Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness may be determined by the procedure in ASME/ANSI B31G or the procedure in AGA Pipeline Research Committee Project PR 3–805 (with RSTRENG disk). Both procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations prescribed in the procedures.

4.2.3 192.485 Remedial measures: Transmission Lines

(1) Temporary pressure reduction. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, see §192.7) or AGA Pipeline Research Committee Project PR–3–805 (“RSTRENG,” incorporated by reference, see §192.7) or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered.

4.2.4 195.587 – What methods are available to determine the strength of corroded pipe?

Under §195.585, you may use the procedure in ASME B31G, “Manual for Determining the Remaining Strength of Corroded Pipelines,” or the procedure developed by AGA/Battelle, “A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe (with RSTRENG disk),” to determine the strength of corroded pipe based on actual remaining wall thickness. These procedures apply to corroded regions that do not penetrate the pipe wall, subject to the limitations set out in the respective procedures.

4.3. Finding and Measuring the Corrosion

The technician must identify the reference typically the U/S girth weld and verify boxed or clustered features as outlined by ILI vendor. See figure below.
4.3.1 ILI Boxing or Clustering
U/S Girth Weld

4.3.2 Manual Gridding and Clustering

Manual pit gauge measurements require that corrosion pitting be clustered based on operators interaction rules and laid out in a grid pattern (typically 1 inch) as shown in the figure on the next page. In addition, once the depth readings are measured and recorded in each grid, then the technician must determine the river bottom of the deepest corrosion features. This task is tedious, methodically and is error prone in every step based on the number of readings. Depending on the size of pipe, length, width and depths of corrosion, it can take over a full 10 hour day.
4.3.3 River Bottom Profile

Below is an example or a river bottom profile of how corrosion might occur and how the parameters of metal loss are configured and measured for analysis: L is the measured axial length of corrosion along the longitudinal axis of the pipe.

4.4. Assessing Corrosion

4.4.1 Level 1

- **Original B31G**, uses a two term Folias factor, Flow Stress = 1.1 SMYS plus the parabolic metal loss representation of \((2/3)\text{Ld}\). – **Most Conservative**

- **Modified B31G**, uses the three term Folias factor, Flow Stress = SMYS + 10,000, and the metal loss as a rectangular area = to .85Ld. - **Less Conservative**

4.4.2 Level 2 – Effective Area Method

- **RSTRENG**, uses the three term Folias factor, Flow Stress = SMYS + 10,000 and multiple measurements of the corrosion for identifying the Effective Area of metal loss. – **Most Accurate**
4.5. Interaction Rules

Corrosion occurs where multiple metal loss areas are closely spaced axially and circumferentially. Where they are spaced closely to impact the strength of corroded pipe, the metal loss will interact resulting in lowering the pressure.

4.5.1 ASME B31.8

According to B31.8, flaws that interact spaced longitudinal and circumferentially within a distance of 3 times the wall thickness must be evaluated as a single flaw. If they outside this minimum dimension they can be evaluated as separate flaws.

On the next page is how separate flaws are measure to determine if they are spaced within the minimum distances of 3 times the wall thickness
4.6. Limitations

“These procedures should not be used to evaluate the remaining strength of corroded girth or longitudinal welds or related heat affected zones, defects caused by mechanical damage, such as gouges and grooves, and defects introduced during pipe or plate manufacture, such as seams, laps, rolled ends, scabs, or slivers.” Other limitations include pipe vibration, fittings, wrinkle/ripple bends, etc.

- Crack-like defects.
- Combined corrosion and crack-like defects.
- Combined corrosion and mechanical damage.
- Metal loss defects due to mechanical damage (e.g. gouges).
- Metal loss in indentations and buckles, or metal loss that is coincident with other damage.
- Metal loss in fittings.
- Pipelines that operate at temperatures outside their original design envelope or operating at temperatures in the creep range.

4.7. Calculations with RSTRENG Program

4.7.1 Updating Existing Project Files

After user enters the Location of Pitting, the pipe OD, Wall Thickness and SMYS and begins entering a Design Factor, a supporting screen appears with MAOP values for noted Design Factors. See screen shot on next page of a Site Input Screen.
4.7.2 Opening New Project Files

The corrosion data can now be entered either by pasting the data from an Excel spreadsheet, manually inputting the data or from the 3D Pipeline Analysis software. Below are RSTRENG Calculations for a 20" O.D. x 0.250" WT x 52,000 SYMS x Class 1 location.
Below is an RSTRENG PDF Report that was generated using the new RSTRENG 6 Software.

<table>
<thead>
<tr>
<th>Site: TTI</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Station: 520</td>
<td>Date: 12/18/2014</td>
</tr>
</tbody>
</table>

\[ P = 2SL/FT/D \ [\text{psi}] - \text{Calculated Pressure} \]

\[ \text{Established MAOP} \ [\text{psi}] \]

\[
\begin{array}{|l|l|}
\hline
\text{Pipe Outside Diameter} \ [\text{inches}] & 30 \\
\text{Pipe Wall Thickness} \ [\text{inches}] & 0.312 \\
\text{SMYS} \ [\text{psi}] & 52000 \\
\text{Design Factor} & 0.72 \\
\text{Total Length} \ [\text{inches}] & 123.655 \\
\text{Effective Length: Start} \ [\text{inches}] & 165.974 \\
\hline
\end{array}
\]

\[
\begin{array}{|l|l|l|l|}
\hline
\text{Method} & \text{Max. Safe Pressure} \ [\text{psi}] & \text{Burst Pressure} \ [\text{psi}] & \text{Safety Factor} \\
\hline
\text{RSTRENG - Effective Area} & 638.383 & 886.643 & 1.13964 \\
\text{RSTRENG - 0.85 dL} & 445.427 & 618.649 & 0.795178 \\
\text{ASME B31G} & 296.525 & 411.84 & 0.529357 \\
\hline
\end{array}
\]

**RESULTS OF ANALYSIS:**

**CORROSION PROFILE:**

[Graph showing corrosion profile]

Prepared By: John Smith

Approved by:
4.8. Using 3D Structured Light with RSTRENG

Using 3D structured light digital data acquisition and analysis allows the operator to assess, make feature comparisons and correlations automatically. Analysis can be used quickly for Level 1 and 2 assessments using RSTRENG, ASME B31.G and Modified B31.G for corrosion and ASME B31.8 for dents.

4.8.1 Accurate 3D measurements

In order to achieve accurate 3D measurements of the extent and impact of damage on a pipeline, the parent metal or surface of the pipe needs to serve as a baseline for the 3D analysis. Using 3D measurements representing the current condition of the pipe, the data is automatically separated into both damaged and undamaged regions of the pipe. Once the undamaged points have been identified, these points can be used to form surfaces, which then become the reference against which damaged areas are measured to determine the extent of metal loss or metal deformation. The overall data acquisition process consists of the following as shown in figure on the next page.

Portfolio of 2D scan in sandbox and 3D scan in workspace.

4.8.2 Pipeline Analysis in figure

- Corrosion using selectable interaction rules and grid patterns
- Dents using ASME B31.8 and Modified ASME B31.8
Above surface features such as welds
Combinations of all defects

Pipeline Analysis of Each Corrosion Defect showing maximum depth, area, width and length with color coding for each defect.

Once the scan data has been analyzed using the appropriate grid size, interaction rules, and then the remaining strength of corroded pipe (RSTRENG) can begin as shown in figure on the next page.

- Maximum Safe Pressure
- Burst Pressure
- Safety Factor
- Graph and Report
RSTRENG (Effective Area), Modified B31.G and B31.G Calculations

All tools have errors. The table below is a summary of the major sources of 3D tool error associated with the use of 3D data to determine metal loss and metal deformations.

4.9. Mitigation/Repair

Defects discovered during initial inspections are found in the operators Operations and Maintenance (O&M) plan. The plan includes the methods and timing of all repairs. The required repair schedule interval begins at the time once the condition is discovered.

4.9.1 Repairs

Defect repairs can be divided into three groups and repair intervals. Performance based repairs are determined by engineering critical assessments (ECAs).

• Immediate
• Scheduled
• Monitored

4.9.2 Mitigation
Anomalies requiring immediate repair are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. Example, this may include any external corrosion with depths exceeding 80% of the pipe wall thickness or corroded areas that have a failure pressure level less than 1.1 times the MAOP as determined by an engineering critical assessment procedure such as B31G or RSTRENG.

• Reduce Pressure
• Repair
  o Type B pressurized sleeve
  o Type A reinforcing sleeve
  o Composite reinforcing sleeve
  o Direct weld metal deposition
  o Leak clamp
  o Grind or buff out
• Replace Cylinder of Pipe
• Recoat

4.10. Documentation (Complete)
Integrity Management quality assurance outlines the necessary documentation for the integrity management program. A “Complete” program should include the processes, the inspections, mitigation activities, and prevention activities. Below are some of the processes required for a “Complete” program.

• Provide the sequence of inspection(s) and field interaction of these processes
• Ensure that the criteria and verification for these processes are effective
• Measure, analyze and record these processes
• Implement mitigation actions to achieve results for continued improvement of these processes

4.11. Additional Training
An operator’s integrity management program should include applicable activities to prevent, and minimize the consequences of unintended releases from time dependent features such as corrosion. Technical Toolboxes offers training to help better understand these issues which include:

• RSTRENG
• Integrity Verification & Engineering Critical Assessment
• Defect Assessment
• Cathodic Protection

Section 5 REFERENCES

1. NACE Standard RPO102 (latest revision), “In-Line Inspection of Pipelines” Houston, TX
2. NACE Standard RP0313 (latest revision), “Guided Wave Applications for Pipelines”, Houston, TX
3. NACE Standard RP0502 (latest revision), “Pipeline External Corrosion Direct Assessment Methodology”, Houston, TX
4. ASME B31.8 (latest revision), Gas Transmission and Distribution Piping, New York, New York

Should there be any questions, please feel free to contact:

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