ENERGY TRANSFER

Investigation of Pipeline Anomalies

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	**Procedure No.: HLD.36**	
	Effective Date: 04/01/18	**Page 1 of 18**

1.0 Procedure Description

This Standard Operating Procedure (SOP) provides protocols for investigating anomalies to obtain data regarding the status and root cause of the mechanism. Sections of this SOP are applicable to both anomalies discovered above grade, or following excavation of the pipeline.

2.0 Scope

This SOP describes the process to characterize various pipeline anomalies including external corrosion, internal corrosion, SCC, and geometric deformation.

3.0 Applicability

This SOP applies to investigations and evaluations of pipeline anomalies resulting from ILI tool assessments, hydrotest failures, leaks, or routine exposures or visual inspections that reveal metal loss or deformations.

4.0 Frequency

As required: Resulting from pipe inspections (as per *SOP HLD.35 Pipe Inspections and Evaluations*)

5.0 Governance

The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	**Responsibility**	**Accountability**	**Authority**
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	**Definitions**
Active Corrosion	The chemical or electrochemical reaction between a material, usually a metal, and its environment that produces a deterioration of the material and its properties
Excavation Reference Point	Measurements from a known control point
Control Point	An above grade location such as a valve, road centerline, or AGM from an ILI run

7.0 Investigation of Pipeline Anomalies

The following procedures are described in this SOP:

- Documentation of construction and operating parameters
- Site location verification
- Corrosion measurements
- Photographs
- Local topography
- Soils classification
- Pipeline Coating condition
- Fluid sampling and analysis
- Corrosion deposits
- Bacteria Testing
- Determination of active corrosion
- Characterization and mapping of corrosion defects
- Characterization and mapping of deformation measurements
- Characterization and mapping of SCC defects

Excluding *7.1 Documentation of Construction and Operating Parameters*, record all data from *Section 7.0* in the Pipeline Inspection Database (Gforms).

7.1 Documentation of Construction and Operating Parameters

Operations Personnel generate and review applicable reports from the Geospatial Information System (GIS) about the pipe segment to be inspected.

The data review includes, but is not limited to the following:

- Alignment Sheets
- AGM Report
- In-Line Inspection Report
- Pipe Segment with MOP Report
- Coating Report
- HCA Report
- O&M Review
- CP Test Point Data
- CP Rectifier Data
- Interference Bond Data
- Close Interval Survey Data

7.2 Site Location Verification

Operations Personnel follows the procedure below prior to excavation. Refer to Appendix B: Control and Reference Points.

Step	Activity
1	**SURVEY** the location of the pending excavation or the area where external corrosion was identified.
2	**REFERENCE** above grade locations to a known control point such as a valve, road centerline, or AGM from an ILI run.
3	**USE** the same control point as a reference to determine stationing of pipe features following excavation.
4	**ESTABLISH** an excavation reference point and **ESTABLISH** the Station Number of the reference point with respect to the same control point used prior to excavation.
5	**REFERENCE** all features within the excavation (girth welds, limits of excavation, features, etc.) to the Excavation Reference Point as shown in Appendix B.

NOTE: The Excavation Reference Point allows for rapid, accurate measurement of features.

6	**SELECT** the farthest upstream girthweld exposed in the excavation as the Excavation Reference Point. If no girthwelds are exposed, **REFERENCE** all features to a Control Point on the pipeline.
7	**CONVERT** footages to pipeline stationing.

7.3 Corrosion Measurements

Operations Personnel follows the procedure below for corrosion measurements.

Step	Activity
1	**MEASURE** and **RECORD** potentials and rectifier output at the nearest upstream and downstream test stations/rectifiers. Enter data into Gforms and Corrosion database.
2	**INVESTIGATE** readings to verify that potentials obtained at the excavation site are representative of normal operating conditions.

NOTE: Verification provides answers to a number of conditions caused by inoperable rectifiers, construction activity in the area, unusual weather events, shorted casings, shorted insulation, etc. Non-operational rectifiers are repaired and returned to service (if practical) before obtaining CP readings at the excavation site.

7.3.1 Close Interval Surveys

If requested by the Pipeline Integrity Specialist, Operations Personnel performs the procedure below for Close Interval Surveys (CIS).

Step	Activity
1	**PERFORM** a close interval and side drain survey where requested by the Pipeline Integrity Specialist.
2	**BEGIN** the survey a minimum of 100 feet upstream of the area of excavation and **END** the survey a minimum of 100 feet downstream of the area of excavation.
3	**CONDUCT** the survey in accordance with *SOP HLD.15 Close Interval Survey*.
4	**PERFORM** the survey with rectifiers on, unless equipment is available to perform an interrupted survey.
5	**REDUCE** electrode spacing (typically 3 – 5 feet) to one foot if piping in the area contains wrinkle bends or is coated with tape.

7.3.2 Soil Resistivity

If requested by the Pipeline Integrity Specialist, Operations Personnel performs the soil resistivity test procedure described below.

Step	Activity
1	**MEASURE** and Document in the Pipeline Inspection Database (Gforms), soil resistivity transverse to the pipeline at 2.5, 5, 10, and 20-foot increments, using the Wenner 4-Pin Method. Refer to *SOP HLD.06 Soil Resistivity Measurement* for detailed procedures on performing the Wenner 4-Pin test.
2	**TAKE** resistivity measurements in undisturbed soil, near the center of the excavation.
3	**REPEAT** resistivity test if excavation indicates significant changes in soil types (e.g., rock outcrop).

7.4 Photographs

Operations Personnel performs the procedure below for photographs. Not every pipe inspection calls for the details photographs provide. Obtain direction from the Corrosion Specialist as to when photography is useful.

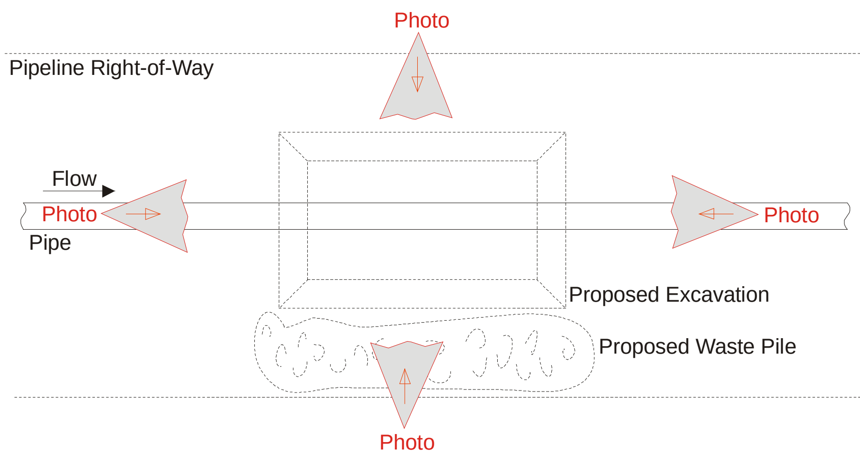

Figure 1: Schematic showing location of recommended photographs

Step	Activity
1	**OBTAIN** a photograph prior to excavation to document site conditions, as shown in Figure 1.

NOTE: Figure 1 illustrates the location and direction of the recommended photographs that should be obtained during the site verification phase.

Step	Activity
2	Clearly **DOCUMENT** the purpose of the photograph and where it was obtained on the pipeline system (discharge/valve section/station range).

NOTE: A small dry erase board is ideal for this application.

Step	Activity
3	Clearly **SHOW** the item or items that justified taking the photograph.
4	**INCLUDE** some frame of reference to provide a scale for the photograph. If the photograph is of the site, **INCLUDE** a person or a piece of equipment for scale. If the photograph is of a defect on the pipe, **INCLUDE** a ruler or other item for scale.

Step	Activity
5	**IDENTIFY** orientation of the defect (clock position), direction of product flow, wheel count of the defect (as applicable), and severity of the defect (length, depth, width).
6	**DOWNLOAD** digital pictures and **RENAME** each picture file using a short description of the contents of the photograph.
7	**PHOTOGRAPH** all corrosion, dents, SCC, or other defects for future reference.
8	Prior to taking a photograph, **RECORD** the following information: • Pipeline Name and Number • Location (Site ID, Joint ID, and Survey Station) • Defect ID • Flow Direction • Date
9	**ATTACH** photographs to Pipe Inspection Database (Gforms).

7.5 Local Topography

Operations Personnel characterizes the excavation site with respect to site topography, as indicated in Figure 2. The topography is particularly useful for SCC characterization and is obtained at the direction of the Corrosion Specialist

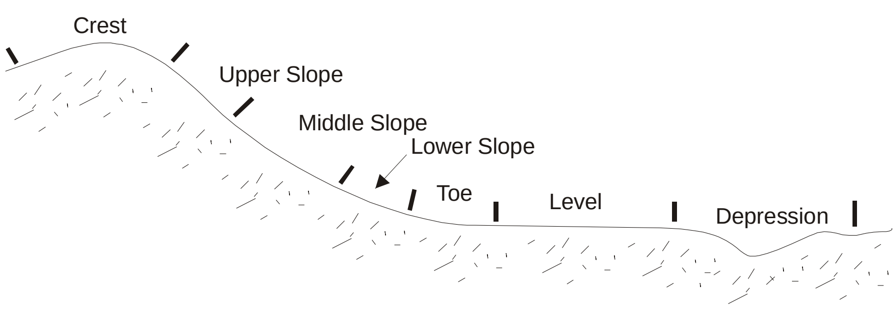

Figure 2 – Topography Criteria

NOTE:
- Crest: the uppermost portion or apex of a slope
- Upper slope: the uppermost portion of a slope immediately below the crest
- Middle slope: the area between the upper and lower slopes
- Lower slope: the lower portion of a slope immediately above the toe
- Toe: the lowermost portion of a slope
- Level: any level area
- Depression: any area that is concave in all directions

7.6 Soil Classification

Operations Personnel performs the procedure below for soil profiles. The classification of the soil is particularly useful for SCC characterization and is obtained at the direction of the Pipeline Integrity Specialist

Step	Activity
1	**INSPECT** the faces of the excavation for transitions in the soil profile.
2	**CLEAN** and **PHOTOGRAPH** the face of the transition with a shovel or trowel to provide a clear view of the soil profile.
3	**PERFORM** face preparation with a horizontal motion to avoid up/down smearing of soil horizons. **INCLUDE** a scale in all photographs of soil profile transitions.

7.6.1 Soil Types

Operations Personnel classifies the soil type(s) at each excavation based on the mode of deposition and the texture. Listed below are the various soil environment descriptions:
- **Fluvial**: sorted and stratified sandy and/or gravel textured material; includes alluvial sand and gravel derived from relict watercourses
- **Till**: variable soil texture with variable size range of unsorted stones; includes gravel, sand, clay, and silt that were glacial in origin
- **Organic over Clay**: non mineral organic soils over clay
- **Organic over Gravel**: non-mineral organic soils over gravel
- **Rock**: < 1 meter of soil cover over rock or bedrock
- **Lacustrine**: typically fine textured deposits, clay to silt, with well-defined stratification; deposits formed in standing bodies of water
- **Alluvial**: commonly rocky, gravel textured, recently deposited sediments that are stream derived

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7.6.2 Soil Type/Grain Size

Operations Personnel examines soils from each Profile Transition and characterizes soil types and grain sizes using descriptions contained in Table 1.

NOTE: Pipeline backfill with grain sizes smaller than 2 mm (clays, silts, and sands) have an increased capacity to trap/hold water, resulting in higher stress levels on pipeline coatings.

Table 1: Soil Types and Grain Sizes

Soil Type	Grain Size
Clay	<0.002mm
Silt	0.002 – 0.05mm
Sand	0.05 – 2.0mm
Gravel	2.0 - 80mm
Cobble	80 - 250mm

7.6.3 Soil Drainage Classification

Operations Personnel determines the soil drainage at pipe level based on soil characteristics such as depth of mottling and gleying or the absence of soil drainage impediments from the soil surface. Listed below are the definitions of drainage classifications:

- Well Drained (W): oxidizing environment throughout the year
- Imperfect Drained (I): alternating oxidizing and reducing environment, as a result of a fluctuating water table
- Poorly Drained (P): primarily reducing conditions; may be saturated throughout most of the season
- Very Poorly Drained (VP): reducing conditions throughout the entire year; the soil would be saturated year round
- Very Poorly – Very Poorly Drained (VP-VP): reducing conditions throughout the entire year; the soil would consist of organic material and would be saturated year round; standing bodies of water on surface

7.7 Pipeline Coating Condition

Operations Personnel inspect and document the condition of the pipeline coating for all portions of exposed piping, using photographs and classifications contained in Table 2.

Table 2: Pipeline Coating Condition

Coating Condition	Description of Disbonded Coating
Excellent	Very good adhesion; less than 1% disbondment; occasional holiday
Well	1 to 10% disbondment; scattered holidays; isolated soil stresses with no associated deposits; clear electrolyte; good adhesion
Fair	10-50% disbondment; intermittent soil stress indications; coating damage; scattered to numerous holidays; random areas of poor adhesion

Coating Condition	Description of Disbonded Coating
Poor	50-80% disbondment; numerous holidays; multiple to continuous areas of poor adhesion; interlinked soil stresses with associated deposits; coating damage
Very Poor	>80% coating failure; no adhesion; numerous holidays; interlinked soil stress associated with corrosion deposits

7.7.1 Coating Adhesion Testing

Operations Personnel assesses coating adhesion of bitumen and asphaltic coatings by striking coating firmly with a brass hammer.

NOTE:

- If impact results in a dimple and/or minor damage to the coating, coating adhesion is good.
- Hammer strikes to disbonded coatings will result in large areas of removed coating.
- Photo documentation should include overview photographs of the pipe and coating within the excavation; coating photographs on a joint by joint basis from each side of the pipe; and detailed photographs of coating conditions, such as tenting, holidays, wrinkles, disbanded areas, etc.

7.8 Fluid Sampling and Analysis

Operations Personnel follows the procedure below for fluid sampling and analysis.

Step	Activity
1	**COLLECT** samples of any fluids trapped beneath the coating and pipe wall.
2	**MEASURE** pH. **SUBMIT** balance of sample for laboratory analysis if directed by Pipeline Integrity Specialist.
3	**UTILIZE** sterile syringes for collecting fluid samples beneath coatings. At least 5 mL of fluid is required for laboratory analysis.

NOTE: Moisture trapped between the coating and pipe wall may not be of sufficient volume to collect a sample. The pH of this area may be determined by placing pH paper directly onto the moist pipe.

Step	Activity
4	**TRANSFER** liquid samples to sterile sample bottles (Vacutainers) supplied by the testing laboratory. **PRESERVE** liquid samples by placing on ice away from direct sunlight until delivery to lab.

Step	Activity
5	**CONSULT** with Pipeline Integrity Specialist for approved laboratories and analytical parameters.
6	**PERFORM** bacterial testing per guidance from *SOP HLD.39 Bacterial Corrosion Tests* whenever corrosion, corrosion deposits, or fluids are encountered. Document results in Pipe Inspection Database (Gforms).
7	Electrolytes associated with classical SCC have a pH range between 8.5 and 11.0 standard units (su). Electrolytes associated with non-classical SCC have a pH range between 6.0 and 8.5 su. **CONSULT** with Pipeline Integrity Specialist if pH of fluids trapped beneath disbonded coatings is within either range to determine whether magnetic particle inspection (MPI) is required.

Figure 3: Fluid Sampling Equipment and pH Paper

7.9 Corrosion Deposits

Operations Personnel follows the procedure below for corrosion deposits.

Step	Activity
1	**INSPECT** areas of the coating that appear to have disbondment or are damaged for corrosion deposits and electrolyte accumulation.
2	**VERIFY** materials and equipment used to obtain samples of corrosion products are immediately available upon discovery; however, excavation of the pipeline often provides adequate air to change the chemistry of corrosion deposits.
3	If corrosion deposits are encountered during the coating inspection, **PHOTOGRAH** a representative number of the corrosion deposits.

Step	Activity
4	**VERIFY** each photograph is clear, taken at a suitable distance, and includes: • Location (Site ID, Joint ID, and Survey Station) • Feature ID • Flow Direction • Date
5	**IDENTIFY** corrosion deposits and **CATEGORIZE** according to color, texture, and distribution using the following industry standards and characteristics: • Iron carbonate ($FeCO_3$) – typically white and pasty • Calcium carbonate ($CaCO_3$) – typically white and powdery • Iron hydroxides and oxides (FeO[OH], Fe_3O_4) – typically orange and powdery or scaly • Nacholite ($NaHCO_3$) – white crystals • Magnetite (Fe_3O_4) – black and powdery
6	**SAMPLE** the corrosion deposits with sterile equipment to verify the sample is not contaminated.

NOTE: Typically the sampling can be performed using equipment that has been washed with soap and water, rinsed with an alcohol such as rubbing alcohol, and then rinsed with deionized water.

Step	Activity
7	**SCRAPE** deposit from pipe into plastic vial.
8	**OBTAIN** a minimum of 2 g's of sample product (laboratory requirement).
9	**VERIFY** vial is sealed and labeled properly.
10	**STORE** in a dry Ziploc bag with other corrosion product samples.
11	**STORE** samples in cooler with ice in it. **KEEP** away from direct sunlight.
12	**PERFORM** bacterial testing per guidance from *SOP HLD.39 Bacterial Corrosion Tests* whenever corrosion, corrosion deposits, or fluids are encountered. Document results in Pipe Inspection Database (Gforms).

7.10 Determination of Active Corrosion

The Pipeline Integrity Engineer classifies corrosion as active if any two of the following conditions are met:

- Pre-excavation CIS and Side drain surveys confirm that current was leaving the pipeline at a corrosion defect
- Laboratory analysis of corrosion deposits confirms that corrosion was Active

- Visual inspection reveals a layer of white corrosion product with the consistency of paste that can be removed with finger pressure to reveal bright metal

NOTE: Visual identification of active corrosion is extremely difficult, if not impossible. “Rules of Thumb” such as the presence of white pasty corrosion deposits or clean metal beneath corrosion deposits may indicate active corrosion under certain conditions.

7.11 Characteriza - tion and Mapping of Corrosion Defects

Operations Personnel follows the procedure below for assessment and mapping.

Step	Activity
1	**COMPLETE** the Corrosion Assessment to determine the remaining wall thickness of the pipeline that can be used to determine the remaining strength of the pipe. *SOP HLD.47 Evaluation of Remaining Strength of Pipe with Metal Loss*.
2	**MAKE** remaining wall measurements indirectly by measuring the depth of the defect or directly by measuring the wall thickness using a non-destructive testing method such as ultrasonics.

7.11.1 Pit Gauges

Operations Personnel follows the procedure below for pit gauges.

Step	Activity
1	When using indirect methods to measure remaining wall thickness, **SUBTRACT** the measurement of the pit depth from the known uncorroded wall thickness.

NOTE: The equipment that may be used for indirect measurements include:
- Pit gauges
- Scales or profile gauges
- Micrometers
- Bridging bars
- Straight edges or rulers

Step	Activity

2	**USE** a bridging bar where a larger area is corroded to provide a suitable measurement surface.
3	**RAISE** the bridging to accommodate the weld cap, if necessary.
4	**ADJUST** the depth measurements for the raised amount to provide accurate measurements.

7.11.2 UT Measurements

Operations Personnel follows the procedure below for UT measurements.

Step	Activity
1	**USE** an ultrasonic thickness gauge for complex lakes of corrosion or where pit gauges are impractical.
2	To obtain accurate measurements using the ultrasonic equipment, **FIT** the tip of the ultrasonic probe within the corrosion feature.

NOTE: This may not be difficult in general corrosion but may prove more difficult in high relief channel and pitting corrosion.

Step	Activity
3	**DO NOT USE** a bridging bar during the ultrasonic thickness measurement as this device measures the remaining wall thickness.
4	When directed by the Pipeline Integrity Engineer, **CONSIDER** using an automated system that utilizes ultrasonics that allow for both pit depth and remaining wall measurements to be obtained.

NOTE: Automated inspection systems provide the ability to map corrosion features efficiently and accurately.

7.12 Characterization and Mapping of Deformation Measurements

Operations Personnel follows the procedure below for characterization of deformation anomalies.

Step	Activity
1	**USE** indirect methods to assess dents as they are not the result of wall thinning but rather the result of a deformation of the pipe curvature.
2	**USE** a pit gauge, ruler, bridging bar, or carpenter's profiler if the area is extensive to determine the depth of the dent.

3	**SET UP** a grid over the dented area and obtain a suitable number of measurements within the grid.

NOTE: If the dent is small, there may be no need to perform a grid inspection but rather a simple maximum dent depth and axial and circumferential extent measurements.

Step	Activity
4	**PERFORM** magnetic particle inspection on 100% of the dent area to verify cracking has not initiated due to stress risers or ingress of a potent environment. **REFER** to *SOP HLD.45 Wet Magnetic Particle Inspection*.

7.13 Characterization and Mapping of SCC Defects

Operations Personnel inspects where SCC is suspected or is present.

Step	Activity
1	**DO NOT SPECULATE** on the cause of crack like indication as not all linear indications are cracks and not all cracks are SCC. **CONFIRM** with Pipeline Integrity Engineer or Vice President of Pipeline Integrity on the type of feature that is present.
2	**USE** Magnetic Particle Inspection (MPI) to detect defects that are either surface breaking or sub-surface. **REFER** to *SOP HLD.45 Wet Magnetic Particle Inspection*.
3	Once the MPI is complete, **IDENTIFY**, **LABEL**, and **DOCUMENT** all defects that were identified, including corrosion and dents. **INCLUDE:** • Line Name and Number • The Joint ID • The type of defect • The defect ID • Date
4	**LOCATE** the defect position of the sample relative to the excavation reference point.
5	**OBTAIN** the position by (a) measuring the distance upstream or downstream from the reference point and (b) measuring the circumferential distance around the pipe either clockwise (CW) or counter clockwise (CCW) from the top of the pipe.
6	**RECORD** specifics regarding the SCC colony as shown in the diagrams and note below.

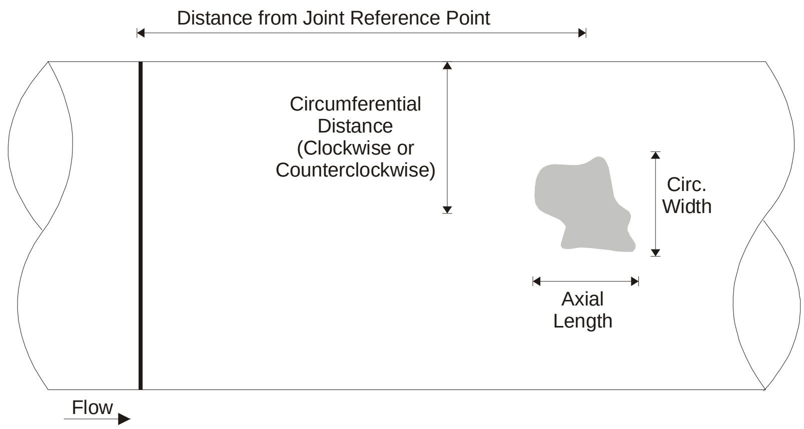

Figure 4: Defect Identification Diagram

NOTE:

- Colony dimensions – including the feature width. It is important that care is taken to delineate colonies using a rule that if cracks are separated by ½ inch (1cm) or more than it is a new colony.
- Average crack length - visually estimate average individual crack length (mm).
- Maximum crack length - measured maximum crack length (mm) within a colony.
- Horizontal distance between cracks - measured distance (mm) between individual cracks.
- Colony location relative to the position of girthwelds and longseams where SCC is located within 4 inches (10cm) of a weld is considered associated with that weld.
- Interlinking - individual cracks that are linked together or about to link together. If cracks are located within 1/25 of an inch (1mm) the cracks are considered interlinked.
- Maximum interlinked length - measured maximum interlinked crack length (mm).
- Crack depth – record the depth as measured only if using grinding to determine the depth of the crack that was removed

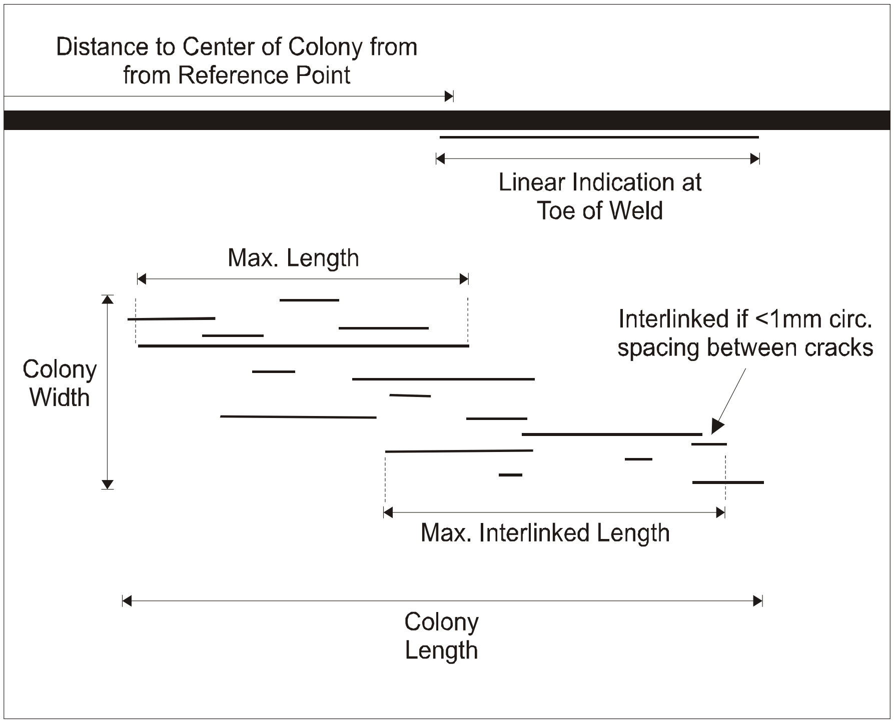

Figure 5: Colony Diagram

8.0 Documentation Requirements

Pipe Inspection database (Gforms) is used to document the information obtained during the investigation of anomalies

9.0 References

HLD.06 Soil Resistivity Measurement
HLD.15 Close Interval Survey
HLD.35 Pipe Inspections and Evaluations
HLD.39 Bacterial Corrosion Tests
HLD.45 Wet Magnetic Particle Inspection
HLD.47 Evaluation of remaining Strength of Pipe with Metal Loss
For Direct Examination refer to the Integrity Management Plan (IMP)

Appendix A: OQ Task Requirements

There are no Operator Qualification (OQ) tasks required for this SOP.

Appendix B: Control and Reference Points

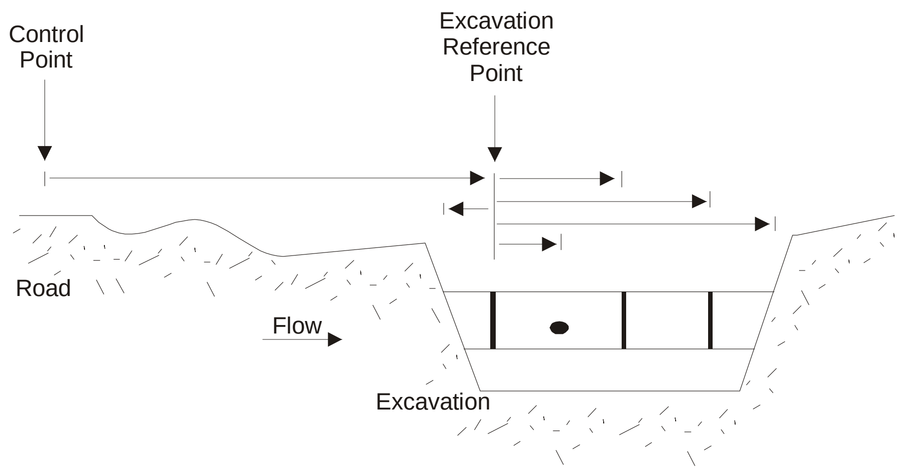

Figure 6: Control Point and Reference Points Diagram

Appendix C: Corrosion Diagram

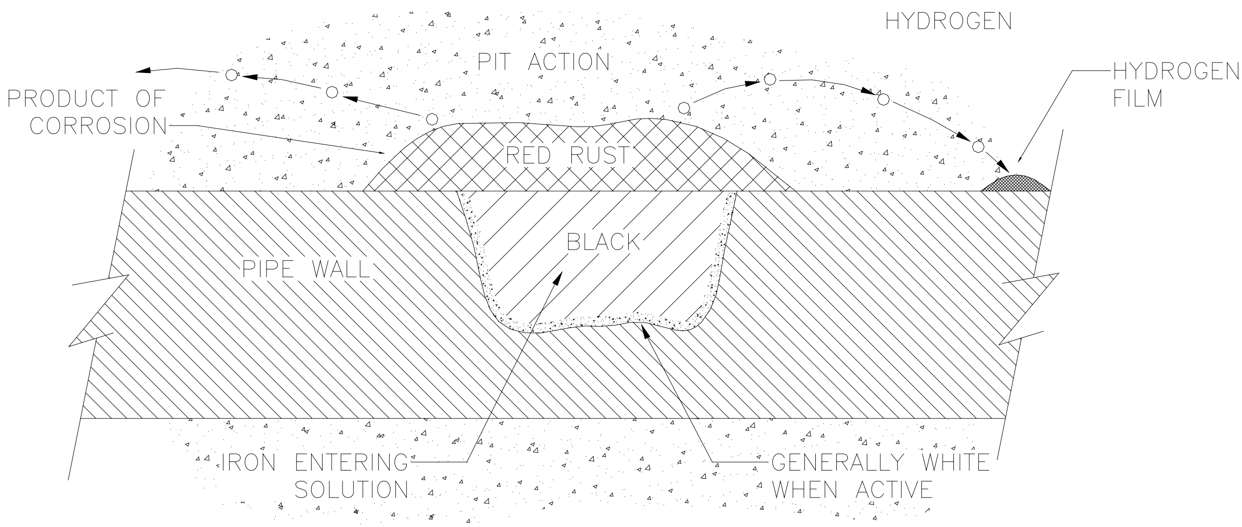

Figure 7: Corrosion Diagram

NOTE:

- $Fe = Fe^{++} + 2e^-$ (Oxidation at Anode)
- $Fe^+ + 2(OH)^- = Fe(OH)_2$ (ferrous hydroxide – white)
- $Fe(OH)_2 + O_2 = 2\ Fe_3O_4 + 6\ H_2O$ (magnetite - black)
- $Fe_3O_4 + O_2 = Fe_2O_3 + H_2O$ (iron oxide or hematite)

ENERGY TRANSFER

Analysis of Solid, and Liquid Samples

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	**Procedure No.: HLD.38**	
49 CFR 195.579	***Effective Date: 04/01/18***	**Page 1 of 4**

1.0 Purpose

This Standard Operating Procedure (SOP) describes the steps for obtaining and handling of liquid samples, solid samples of corrosion byproducts for further evaluation.

2.0 Scope

Chemical analysis of samples is conducted in order to evaluate potential corrosion activity and determine the effectiveness of corrosion control measures. Corrosion monitoring programs incorporate ongoing sampling and analysis in order to recognize trends for detection, prevention, or verify the effectiveness corrosion control measures.

3.0 Applicability

This SOP applies to all company facilities where solid or liquids samples are collected for corrosion analysis.

4.0 Frequency

As required for analysis and monitoring of corrosion components.

5.0 Governance

The following table describes the responsibility, accountability, and authority for this SOP.

Function	**Responsibility**	**Accountability**	**Authority**
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms.*

Terms	**Definitions**
Chain of Custody	A document following the sample from the field to the lab. Not all samples require a chain of custody.

Terms	**Definitions**
Liquid Sample	A sample with characteristics of easy flowing, running, or pouring capabilities.
Sample	A representative portion of a larger environment.
Solid Sample	A sample of a more firm consistency as compared with a liquid. Some samples may contain both solid and liquid.

7.0
Analysis of Solid, and Liquid Samples

This SOP contains the following sections:

- Liquid sample analysis
- Solid sample analysis
- Handling and shipping

7.1
Liquid Sample Analysis

The following procedures should be used to collect liquid samples.

Step	**Activity**
1	**OBTAIN** liquid samples from a variety of locations, such as pig traps, water traps, valve bodies, sump, metering and pump stations, etc.
2	When conducting an investigation of external corrosion mechanisms, **OBTAIN** liquid samples adjacent to the pipe or trapped beneath coatings. Reference SOP HLD.36

WARNING: Samples are often collected from potentially hazardous locations. Reference applicable company safety procedures and PPE requirements prior to collecting samples.

Step	**Activity**
3	**PERFORM** a primary analysis of water, including the following items for: • pH • Iron (Fe) • Manganese (Mn) • Dissolved (CO2) and (H2S) • Chloride (Cl) • Sulfate (SO4) • Bacteria (SRB) and (APB)

NOTE: Refer to *SOP HLD.07 pH Measurement*, and *SOP HLD.39 Bacterial Corrosion Tests*

NOTE: When the nature of a water sample is characterized as corrosive, consider conducting a review of the internal corrosion monitoring schedule per *SOP HLD.30 Internal Corrosion Monitoring and Mitigation.*

7.2
Solid Sample Analysis

The following procedure is used when collecting solid samples.

Step	Activity
1	**COLLECT** solid samples when performing analysis to investigate corrosion tendencies, corrosion byproducts, scaling tendencies, or paraffin deposition.
2	**OBTAIN** solid samples from receivers following pig runs and water traps.

WARNING: Samples are often collected from potentially hazardous locations. Reference applicable company safety procedures and PPE requirements prior to collecting samples.

Step	Activity

3	**PERFORM** a primary analysis for solids, including the following for:
	• Iron
	    o Iron oxide (FeO) and (Fe2O3) – red corrosion byproduct (iron oxide shown on analysis report could have been (FeS) that has oxidized and changed to iron oxide)
	    o Iron Sulfide – black corrosion byproduct, results when (H2S) reacts with bare metal
	    o Iron Chloride – corrosion byproduct, free dissolved iron
	    o Iron Carbonate – corrosion byproduct
	    o

4	In addition **PERFORM** a primary analysis for wet solids, including the following for: • pH • Bacteria (SRB) and (APB)

7.3
Handling and Shipping

Use the following steps for handling and shipping samples.

Step	Activity
1	**PLACE** samples in appropriate containers for shipping and handling.
2	**LABEL** containers with the following information: • Sample locations • Date sample taken

Step	Activity
	• Type of analysis required • Name of sampler

NOTE: Samples maybe classified as hazardous materials. Consult Environmental Specialist for further instruction.

Step	Activity
3	**VERIFY** that appropriate legal and safety requirements are understood and followed prior to shipment. Consult Safety Representative
4	**VERIFY** samples are obtained promptly and handled in a manner to avoid contamination.
5	**PACKAGE** samples to avoid leakage and/or breakage during shipment. **INCLUDE** notes and remarks.
6	**FOLLOW** “Chain of Custody” requirements for shipping samples, when appropriate.
7	**CONSIDER** potential for increasing vapor pressure when packaging sample for shipment.
8	**SHIP** sample promptly for analysis.

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:

Retain “Chain of Custody” documentation and sample analysis results as necessary.

9.0 References

HLD.07 pH Measurement
HLD.30 Internal Corrosion Monitoring and Mitigation
HLD.31 Evaluation of Gas Quality Upsets in Normally Dry Pipelines
HLD.39 Bacterial Corrosion Tests

Appendix A: OQ Task Requirements

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Collect Sample for Internal Corrosion Monitoring	PLOQ718

ENERGY TRANSFER

Bacterial Corrosion Tests

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference:	**Procedure No.: HLD.39**	
49 CFR 195.579	***Effective Date: 04/01/18***	

1.0 Purpose

This Standard Operating Procedure (SOP) describes testing for the presence of Sulfate Reducing Bacteria (SRB) and/or Acid Producing Bacteria (APB).

2.0 Scope

APB or SRB bacteria may be found in either liquids inside the pipeline or in the environment outside the pipeline. These microbes are primarily responsible for Microbiologically Influenced Corrosion (MIC). Mitigation practices are employed as directed by the IC Specialist, Corrosion Specialist or Engineer.

3.0 Applicability

This SOP applies to company facilities where the presence of corrosion is found on buried structures and where free water is found in the pipeline.

4.0 Frequency

As required: When free water is found in the liquid product stream.

5.0 Governance

The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Nodules	Small mounds of deposits that sometimes form over growing corrosion pits.
Striations	Minute grooves or channels. Typically oriented in the longitudinal direction of the pipe

7.0 Bacterial Corrosion Tests

When the following conditions exist, Operations Personnel perform bacterial testing:

- When a pipeline is suspected of being contaminated with bacteria and water samples are available.
- When corrosion deposits are found on internal and external buried pipe inspections.

The following procedures are described in this section:

- Test Methods
- Visual Examination
- Acid/Smell Test
- Modified Standard API Test
- Serial Dilution (API)
- RapidChek II or Sani-Check Sulfate Reducing Bacteria Detection System
- Sani-Check Acid Producing Bacteria Detection System

7.1 Test Methods

The Operations Personnel use one of following methods to test for SRBs or APBs:

SRBs

- Serial Dilution (API)
- Acid/Smell Test
- RapidChek II® Detection System
- Sani-Check SRB Detection System

APBs

- Visual Examination
- Modified Standard API Test
- Serial Dilution (API)
- Sani-Check APB Detection System

RapidChek II and Sani-Check SRB are equivalent test kits.

7.2 Visual Examination

Operations Personnel follows the procedure below for visual examination.

Step	Activity
1	Visually **INVESTIGATE** a corrosion site for evidence to determine whether the corrosion was microbiologically influenced.
2	**CLEAN** and **STERILIZE** any tools to be used in handling the corrosion product prior to beginning.
3	To prevent sample contamination, **DECONTAMINATE** all equipment used for handling corrosion samples and for processing and testing. **USE** packaged sterile syringes, swabs, depressors, etc.
4	**DECONTAMINATE** auxiliary equipment and tools (such as knife blades and brushes) with 70% isopropyl alcohol, followed with acetone, and then a thorough rinse with distilled water.
5	**WEAR** rubber surgical gloves.
6	**REMOVE** the deposit from the suspected corrosion pits using a tongue depressor, swab, or clean spatula.
7	**PLACE** the corrosion product into a clean container. **USE** a glass slide, bottle, or small bowl.
8	**OBTAIN** PH of pipe surface with litmus paper at pipe surface in areas where fluid is present at pipe surface. If there is no moisture at pipe surface, place a few drops of distilled water on pipe surface and check PH with litmus paper.

CAUTION: Do not use a metal brush to clean, since it can damage the metallurgical pattern.

Step	Activity
9	After removing as much deposit as possible, **CONTINUE** cleaning with a stiff brush (such as a nylon toothbrush).
10	If the dry brush does not completely remove the material, **MOISTEN** and **BRUSH** the deposit again.
11	**DRY** the area by rubbing with an alcohol swab.
12	Carefully **EXAMINE** the suspected site: • First, visually • Secondly, with magnification and a light
13	**LOOK** for these characteristic features of corrosions pits: • Nodules are a possible sign of MIC. • MIC pits are typically composed of several smaller pits that are hemispherical (cup-like) in appearance. • Close examination of pits with MIC may reveal striations (minute grooves resembling parallel scratches) that are oriented in the rolling direction of the steel. • Tunnels can often be observed in the sides of pits with MIC.

Step	Activity
14	**CONSULT** reference material, such as GRI MIC Field Guides, to help in the determination of certain metallurgical properties associated with microbial influenced corrosion.

NOTE: The GRI Guides contain color photographs that depict nodules (including relative size), pit geometry, and tunneling effects that are typical of MIC.

Step	Activity
15	**DOCUMENT** the pit color of the pit contents (gray or black), the metal surface under the deposit as shiny or black, the presence of nodules their color, relative frequency and size the conditions in the Corrosion Database.

7.3 Acid/Smell Test

Operations Personnel follows the procedure below for the acid/smell test in conjunction with the visual examination.

CAUTION: Do not apply the hydrochloric acid directly to the pipeline, as doing so will damage the pipeline.

Step	Activity
1	To the corrosion product removed from the pipeline, **ADD** one normal (1N) hydrochloric acid.

WARNING: Take care not to strongly inhale the fumes generated by this test, as doing so could cause personal injury.

Step	Activity
2	Carefully **SMELL** the gas for the odor of hydrogen sulfide, which smells like rotten eggs.
3	As an alternate**, USE** a test paper saturated with lead acetate solution to determine the presence of hydrogen sulfide gas, H_2S (rotten egg odor). **PLACE** the paper in the top of a test tube containing the sample and acid, and **OBSERVE** the reaction as listed: • Negative: No change = no bacteria. • Positive: o Brown – slight o Black- medium o Silver- heavy bacteria

NOTE:	If the reaction emits gas that smells like hydrogen sulfide, the presence of SRB is indicated.

7.4 Modified Standard API Test

Operations Personnel follow the procedure below for the modified standard API test.

Step	Activity
1	**OBTAIN** two (2) bottles of API culture media appropriate for the type of bacteria to be tested (APB or SRB).
2	**REMOVE** metal seals for the two API vials.
3	**LABEL** Vial No. 1: “Blank” and **LABEL** Vial No. 2: “Sample”.
4	**REMOVE** rubber stopper from vials.

NOTE:	Be careful to keep debris from entering the vials.

Step	Activity
5	**WEAR** rubber surgical gloves when sampling.
6	**REPLACE** the stopper on Vial No.1 and **SHAKE** the vial several times.
7	Visually **INSPECT** to see if Vial No. 1 blackens or becomes cloudy. **DISCARD** both vials and **REPEAT** the sampling process with fresh bottles.
8	**ADD** five (5) grams (about 1/5 ounce) of representative soil sample to Vial No. 2. **RE-STOPPER** the vial and **SHAKE** several times. **USE** either soil sample or corrosion product, if appropriate.
9	If Vial No. 2 blackens (SRB vials) or becomes cloudy (APB vials) within two hours, then **DISCONTINUE** the test. If Vial No. 2 does not blacken (SRB vials) or become cloudy (APB vials) within two hours, then **CONTINUE** to the next step.

NOTE:

- Blackening (SRB vials) or cloudiness (APB vials) within two days indicates very active bacteria. The longer it takes for the vials to become blackened or cloudy, the less active the bacteria.
- If no blackening or cloudiness occurs in Vial No. 2 within 21 days, bacteria can be considered absent.
- Keep bacteria test vials out of sunlight during incubation, in a cooler or other enclosed area.

Step	Activity
10	**INCUBATE** the bottles between 15°C (60°F) and 32°C (90°F) for a maximum of 21 days.

NOTE: These temperature limitations may be difficult to sustain at some field locations. Attempt to maintain these temperatures as closely as practical.

Step	Activity
11	**EXAMINE** each vial daily or as practical.
12	**DOCUMENT** the results in the Corrosion database.

7.5 Serial Dilution (API)

Operations Personnel follows the procedure below for serial dilution.

Step	Activity
1	**CULTURE** the corrosion product samples for bacteria analysis on location.
2	**COMBINE** solid products of corrosion with distilled water.
3	**USE** uncontaminated tools to collect 1 ml of sample into a clean sample bottle. **DILUTE** the solid with 10 ml of clean distilled water (verify pH = 7.0), **STOPPER** the bottle with a butyl-type stopper, and **SHAKE**.
4	**OBTAIN** 10 ml nominal capacity (filled with 9 ml of the formulation for the test) serum bottles appropriate for the test to be conducted (SRB or APB). **SEAL** the bottles with butyl-type rubber stoppers. **USE** disposable metallic caps to protect and seal the rubber stopper in place.
5	**TAPE** five to seven (5-7) vials together in a row. **PLACE** numbers on the vials (i.e., 1-5 or 1-7), and **LABEL** with sampling point, location, and date.
6	**REMOVE** metal tab from top of vial without removing metal seal from the stopper.
7	**USE** a sterile disposable syringe to inoculate the first dilution bottle with 1 ml of the corrosion product sample.

NOTE: The syringe is then bent and discarded in a properly marked container.

Step	Activity
8	Vigorously **AGITATE** the inoculated bottle.
9	**USE** another sterile syringe to withdraw 1 ml of the inoculated broth.
10	**INJECT** this withdrawn broth into the second dilution bottle and **REPEAT** the procedure.
11	**CONTINUE** making subsequent serial dilutions of each bottle until the desired number of vials is inoculated.

12	**INCUBATE** the vials at 37°C ± 2°C (99°F ± 4°F), or within 5°C (7°F) of the pipe surface temperature at time of sampling. Keep bacteria test vials out of sunlight during incubation, in a cooler or other enclosed area.

NOTE: These temperature limitations may be difficult to sustain at some field locations. Attempt to maintain these temperatures as closely as practical.

Step	Activity
13	**EXAMINE** each vial daily or as practical.
14	**RETAIN** dilution bottles a minimum of twenty (20) days.
15	**USE** the number of vials showing positive results to estimate the bacteria level in the original system. **USE** *Table 1: Bacteria Level* below for level determination.

NOTE: Bottles that blacken or cloud up are considered positive. Black is positive for SRB, yellow is positive for APB.

Table 1: Bacteria Level

Number of Positive Vials	Bacteria per ml
1	1-10
2	10-100
3	100-1,000
4	1,000-10,000
5	10,000-100,000
6	100,000-1,000,000
7	1,000,000-10,000,000

NOTE: When sampling a system with H_2S present, the sulfate reducer nutrient in Vial No. 1 will often turn positive (black) within 15-60 seconds of inoculation. This occurrence should be considered no growth, if only this vial has turned after 28 days. If Vial No. 2 turns black immediately, consider the sample contaminated and the test invalid.

7.6 RapidChek II or Sani-Check Sulfate Reducing Bacteria Detection Systems

The RapidChek II or Sani-Check SRB (sulfate reducing bacteria) detection systems employs purified antibodies to detect the enzyme adenosine-5'-phosphosulfate (APS) reeducates that is common to all strains of SRB.

Operations Personnel follows the procedure below for this test.

Step	Activity
1	**USE** this test kit for detecting SRB only.
2	**FOLLOW** the procedures provided by the manufacturer.
	NOTE: RapidChek II and Sani-Check SRB are equivalent test kits. Test kits can be used for external pipe surface, soil or corrosion by products along with any solids or liquids found on the interior of the pipe.

7.7
Sani-Check Acid Producing Bacteria Detection System Systems

Operations Personnel follows the procedure below for this test.

Step	Activity
1	**USE** this test kit for detecting APB only.
2	**FOLLOW** the procedures provided by the manufacturer.
	NOTE: Sani-Check test kits can be used for external pipe surface, soil or corrosion by products along with any solids or liquids/water found on the interior of the pipe.

7.8
Remedial Actions for MIC (Internal)

Operations Personnel follows the procedure below for remedial actions when MIC is confirmed as a contributing factor in internal corrosion.

Step	Activity
1	When results from bacterial testing and laboratory analysis indicate MIC as a contributing factor to internal corrosion caused **REFER** to *SOP HLD.30 Internal Corrosion Monitoring and Mitigation* for remedial action guidance.
2	With consultation with IC Specialist, Corrosion Specialist and Manager of Corrosion Services, **DEVELOP** a remedial action plan within 6 months of discovery, to limit the effect of bacteria on corrosion growth per *SOP HLD.30*
3	**DOCUMENT** remedial action plans on applicable form(s).
4	Within one year of implementing the remedial action plans, **CONFIRM** actions have been implemented and have mitigated the effect of MIC based on corrosion monitoring data.

7.9 Remedial Actions for MIC (External)

Operations Personnel follows the procedure below for remedial actions when MIC is confirmed as a contributing factor in external corrosion.

Step	Activity
1	When bacterial testing and corrosion morphology confirm MIC as a contributing factor to external corrosion, **CONDUCT** additional tests to determine extent of affected area along the pipeline.
2	With consultation with Corrosion Specialist and Manager of Corrosion Services, **DEVELOP** a remedial action plan within 6 months of discovery, to limit the effect of bacteria on corrosion growth. The plan may include additional excavations, recoats, increasing cathodic protection throughout the defined area, or other CP enhancements to increase polarization levels and pH at pipe/soil interface.
3	**DOCUMENT** remedial action plans on applicable form(s).
4	Within one year of implementing the remedial action plans, **CONFIRM** mitigative actions have been implemented.

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:
Corrosion Database
GForms Bacteria Test
GForms; Pipe Inspection
D.30.A Internal Corrosion Monitoring Schedule
D.30.B Internal Corrosion Treatment Schedule
D.30.C Annual Review – Internal Corrosion monitoring and Treatment Schedules
D.40.A Corrosion Control Remedial Action

9.0 References

GRI MIC Field Guide
SOP HLD.30 Internal Corrosion Monitoring and Mitigation

Appendix A: OQ Task Requirements

There are no Operator Qualification (OQ) tasks required for this SOP.

ENERGY TRANSFER

Corrosion Control Remedial Action

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	**Procedure No.: HLD.40**	
49 CFR 195.573, 195.583	***Effective Date: 04/01/18***	

1.0 Purpose

This Standard Operating Procedure (SOP) establishes the requirements to initiate and complete remedial action necessary to restore corrosion control to aboveground and below ground structures.

2.0 Scope

This SOP provides a way to track progress on a project from discovery to restoration of adequate corrosion protection.

3.0 Applicability

This SOP applies whenever monitoring reveals deficiencies in corrosion protection as specified by the following so that prompt remedial action is taken to determine the cause and remediate the deficiency:

- Company standards
- Cathodic protection criteria
- Atmospheric inspections

4.0 Frequency

All Facilities

- Restore adequate levels of cathodic protection within one calendar year following discovery, not to exceed 15 months from the date of the deficient reading(s) except in states where intrastate jurisdictional state regulatory requirements are more stringent. Example: Louisiana regulatory requirement is 90 days.
- Restore onshore atmospheric corrosion protection within three calendar years following discovery, not to exceed 39 months from the date deficiencies were discovered.
- Restore offshore atmospheric corrosion protection within one calendar year following discovery, not to exceed 15 months from the date deficiencies were discovered.

5.0 Governance

The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	**Definitions**
Remedial Action Plan	The plan to determine the cause and recommend remediation for detected deficiencies.

7.0 Corrosion Control Remedial Action

When testing identifies that a company facility needs remediation, Operations Personnel performs these procedures to take remedial action:

- Identification of Problem
- Initial Response
- Recommended Actions and Evaluation
- Summary of Results

7.1 Identification of Problem

Perform these steps after an inspection or procedure results in a discovery of a condition requiring action.

Step	**Activity**
1	**IDENTIFY** the condition that requires action to restore adequate corrosion protection.
2	**NOTIFY** Area Management of identified possible problems.
3	**SUMMARIZE** the situation that requires the remedial action.
4	**RELATE** the inspection or procedure that resulted in discovery of the condition requiring action.

7.2 Initial Response

For the initial response to the condition follow these steps.

Step	**Activity**
1	**RECORD** the initial action or proposed recommended action that corrects the problem within a 30-day period in the applicable form(s) for *Corrosion Control Remedial Action.*
2	If actions have been taken to remedy the condition, **RECORD** the actions and the results. **RECORD** whether additional data is required, and **LIST** the actions to obtain the required data.

7.3 Recommended Actions and Evaluation

Use the following steps to document the recommended actions for corrosion control remediation.

Step	Activity
1	**RECORD** the dates and recommended actions taken as remedial action.
2	**EVALUATE** the need for further testing and recommended actions.
3	**DESCRIBE** the tests that need performing and **SUMMARIZE** the expected results along with completion dates and names of persons performing or supervising such tests.
4	With assistance from the Corrosion Specialist/Supervisor, **IDENTIFY** and **RECORD** situations that require any of the following: • Special funding • Further testing
5	If additional funding is required to address the problem, use the following steps: • **OUTLINE** projects requiring funding to address the situation. • **INITIATE** appropriate process through Operations Manager to obtain funding from capital, expense, or other budget sources. • **PROVIDE** appropriate documentation indicating why the additional funding is needed to the Operations Manager including test results, technical justification, compliance requirements, and cost estimates for project completion. • **PROVIDE** estimated start and completion dates.
6	**PROVIDE** detailed comments and recommended action from Corrosion Specialist resulting from further evaluations.

7.4 Summary Results

Follow these steps to provide summary results of the implemented remedial actions.

Step	Activity
1	**SUMMARIZE** all action taken to provide remedial action that restored conditions to acceptable levels of corrosion control.
2	**PROVIDE** a completion statement with signatures of responsible persons involved in the Remedial Action Report for the Corrosion Specialist approval.
3	**COMPLETE** the applicable form(s) for *Corrosion Control Remedial Action.*
4	**SUBMIT** a completed copy of the applicable form(s) for *Corrosion Control Remedial Action* and supporting documentation.

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:

- D.40.A Corrosion Control Remedial Action
- For Cathodic Protection Low Potential Areas, document Low Potential areas in the LPA Editor.

9.0 References

HLD.15 Close Interval Survey

Appendix A: OQ Task Requirements

There are no Operator Qualification (OQ) tasks required for this SOP.

ENERGY TRANSFER

Protective Coating Systems

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	**Procedure No.: HLD.43**	
49 CFR: 195.557, 195.559, 195.561, 195.581	***Effective Date:*** ***04/01/18***	**Page 1 of 7**

1.0 Procedure Description

This Standard Operating Procedure (SOP) describes how to use coating manuals and standards in order to select protective coating systems.

2.0 Scope

This SOP provides guidance for the selection and application of protective coating systems.

3.0 Applicability

This SOP applies to above- and below-ground piping, equipment, and facilities.

4.0 Frequency

As required

5.0 Governance

The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director / Division Vice President

6.0 Terms and Definitions

For general terms, refer to *SOP* HL*A.01 Glossary and Acronyms*.

7.0 Protective Coating Systems

The following procedures are found in this section:

- Color Codes
- Approved Coating Systems
- Application and Inspection Guidelines
- Safety and Environmental Considerations
- Shipping, Handling, and Storage

7.1 Color Codes

Operations Personnel uses the following procedure to select colors.

NOTE: Color codes are not applicable for below-grade coating.

Step	Activity
1	**VERIFY** that the color code selected is in accordance with the company specifications. **REFER** to the “Coating Procedures Manual” and the Engineering Standards **REFER** to Company Engineering Standards for Color Codes.
2	• **INCLUDE** the Federal Standard color number http://www.federalstandardcolor.com/on requisitions, where a Federal Color number exists, to verify matching paint colors.

7.2 Approved Coating Systems

Operations Personnel follow the steps below to select approved coating systems.

Step	Activity
1	**VERIFY** coating systems selected are in accordance with the Company Engineering Standards.
2	**REFER** to Engineering Standards for approved coating systems.

7.3 Application and Inspection Guidelines

Operations Personnel follows the steps below for application and inspection guidelines.

Step	Activity
1	**REFER** to Company Engineering Standards for application and inspection guidelines.
2	**CONDUCT** routine daily inspections of painting projects to verify that proper application methods and results are being achieved.
3	**VERIFY** that environmental conditions are within manufacturer's recommendations.

NOTE: Environmental conditions include relative humidity, dew point, ambient temperature, surface temperature, and wind.

Step	Activity
4	**VERIFY** that surface preparation is in accordance with manufacturer's recommendations.

NOTE: Any defects discovered after coating is removed must be evaluated in accordance with *SOP HLI.06 Evaluating Pipeline Defects.*

Step	Activity
5	**VERIFY** that all coating application equipment meets manufacturer's recommendations and company environmental requirements.
6	**VERIFY** that wet and dry film coating thickness meets manufacturer's recommendations.
7	**VERIFY** that manufacturer's specifications are followed.

NOTE: Specifications include shelf life, pot life, mixing ratio, VOCs, cure time, temperature resistance, and anchor pattern.

Step	Activity
8	**COMPLETE** the applicable form(s) for *Paint Application Inspection.*

7.4
Safety and Environmental Considerations

Operations Personnel follows the steps below for safety and environmental considerations.

Step	Activity
1	**USE** company approved thinners, solvents, and cleaners in accordance with manufacturer's specifications.
2	**VERIFY** compliance with company environmental and safety SOPs.

NOTE: Vintage coatings may contain lead, chromium, or PCBs. Testing is performed prior to start of work to verify that special procedures and related costs are included in the work scope.

Step	Activity
3	**CONSULT** the Environmental Specialist to verify that disposal of blast media, removed paint, solvents, and unused paint is in accordance with company procedures.

7.5
Shipping, Handling, and Storage

Operations Personnel follows the steps below for shipping, handling, and storage considerations.

Step	Activity
1	**VERIFY** that all paint and related materials are on site and meet company requirements prior to beginning work.

NOTE: Products should be in the manufacturer's unopened, original containers bearing a legible product designation, batch number, and/or date of manufacture.

Step	Activity
2	**DO NOT EXPOSE** the content of damaged containers. Prior to use, **VERIFY** that the seal is not broken and the lid and container are not bent or cracked.
3	If mishandling is suspected, thoroughly **INSPECT** the entire shipment.
4	**STORE** and **HANDLE** the materials in accordance with the manufacturer's specifications.
5	**DO NOT OPEN** containers of paints or components except for immediate use.
6	**DO NOT EXCEED** the manufacturer's recommended shelf life.

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:

- Corrosion Database
- D.43.A Paint Application Inspection Report
- D.43.B Paint Application Inspection Log

9.0 References

Engineering Standards

HLI.06 Evaluating Pipeline Defects

Appendix A: OQ Task Requirements

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Visual inspection of buried pipe and components when exposed	PLOQ401
Inspection of the application of above or below ground coatings	PLOQ402
Repair Holidays on new or existing coating	PLOQ403
Visual inspection for atmospheric corrosion	PLOQ417

ENERGY TRANSFER

Atmospheric Corrosion Inspection

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	**Procedure No.: HLD.44**	
49 CFR: 195.583, 195.581, 195.583	***Effective Date:*** ***04/01/18***	**Page 1 of 10**

1.0 Procedure Description

This Standard Operating Procedure (SOP) establishes the requirements and frequency for conducting atmospheric inspections on company assets to detect coating deterioration and corrosion damage.

2.0 Scope

Inspection of metallic assets exposed to the atmosphere is required to control atmospheric corrosion and maintain a protective coating system. With company assets being installed in a wide variety of service environments, local conditions must be considered when evaluating atmospheric corrosion threats.

3.0 Applicability

This SOP applies to all facilities operated and maintained by the company.

4.0 Frequency

Onshore Pipelines - At least once every three calendar years, not to exceed 39 months: Inspect all onshore hazardous liquid piping exposed to the atmosphere, includes At-Grade breakout storage tanks.

Offshore Pipeline - At least once each calendar year, but not to exceed 15 months: Inspect all offshore hazardous liquid piping exposed to the atmosphere.

Offshore Structural Components – At least once each calendar year, as defined by the Bureau of of Safety and Environmental Enforcement (BSEE),

As required: At the discretion of Operations Personnel, in order to maintain safety and integrity of other company metallic assets.

5.0 Governance

The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician and Pipeliners	Operations Manager	Area Director / Division Vice President

6.0 Terms and Definitions

For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

7.0 Atmospheric Corrosion Inspection

This section describes the following procedures:

- Coating inspection criteria
- Evaluation of metal loss defects
- Evaluation of Inspection Results
- Reporting

7.1 Coating Inspection

- Operations Personnel follows the procedures below to visually inspect metallic assets exposed to the atmosphere for atmospheric corrosion and coating deterioration. which include but is **NOT LIMITED** to the following sites/locations:
  - Wellhead SitesPump Stations
  - Tank Farms
  - Measuring Station
  - Mainline Valve Sites
  - Pipeline Spans
  - Insulated Covered Pipe
  - Emergency Stock Pipe

Step	Activity
1	**INSPECT** and **EXAMINE** concealed areas for moisture traps which may hold water against the pipe. **GIVE** special attention to flanges, pipe resting on support piers, pipe underneath tie-down straps, pipe under insulation, piping at through-wall or deck areas, piping at the air to soil interface, or where damaged coating is visible.
2	At wellhead sites, **INSPECT** all portions of wellhead equipment on storage or producing wells, to include each soil/air interface.
3	At pump stations, **INSPECT** all liquid pressure piping inside and outside of the buildings to include through wall piping, fuel supply lines, blow downs, operator valves, and volume bottles. **EXAMINE** concealed areas under straps or supports, pipe in valve canopies/vaults, pipe under insulation, and each soil/air interface.

WARNING: Ensure that removal of pipe supports/straps/tie downs, will not affect equipment alignment and create vibration issues prior to inspection.

Step	Activity
4	At stations and meter houses, **INSPECT** all piping inside and out of the buildings to include through wall piping, drip lines, tap valves, blow downs, volume bottles, and operator valves,. **EXAMINE** concealed areas under straps or supports, pipe in valve canopies/vaults, pipe under insulation, and each soil/air interface.
5	At tank farms **INSPECT** tanks and manifold piping
6	At main line valves, **INSPECT** all valves and pipe risers including pipes within valve canopies and vaults. **EXAMINE** concealed areas under straps or supports, and each soil/air interface.
7	For pipeline spans, **INSPECT** all portions of pipeline spans and supporting structures. **EXAMINE** concealed areas under straps or supports and each soil/air interface.
8	For insulated covered pipe, **REMOVE** selected areas of insulation to inspect the pipe surface. **BASE** location and size of each inspection on: • Component function

Step	Activity
	• Size • Surface conditions that indicate insulation deterioration • Leaks or corrosion damage found • Inspection results

NOTE: Consider permanent inspection ports on piping covered with insulation to facilitate future inspections without insulation removal.

Step	Activity
9	For emergency pipe, **CHECK** stored piping exposed to direct sunlight for deterioration of the pipe coating system.

CAUTION

CAUTION: Emergency pipe exposed to direct sunlight should be top coated with a UV resistant coating system. Thinned latex paint is an acceptable topcoat for white washing non UV resistant coatings.

7.2
Pipe Inspection

Operations Personnel uses the following steps to evaluate metal loss found during an atmospheric inspection.

Step	Activity
1	**EVALUATE** any defects at the time of discovery.

NOTE: Specialized equipment and/or scaffolding may be required to safely access and evaluate a defect. In such cases, **CONSULT** the pipeline integrity engineer to determine if a pressure reduction is required until the defect can be evaluated.

Step	Activity
2	**EVALUATE** the remaining strength of the metal loss defect in accordance with *SOP HLD.47 Evaluation of Remaining Strength of Pipeline Metal*.
3	**EVALUATE** pipe deformations, manufacturing/construction defects, and/or stress concentrators in accordance with *SOP HLI.06 Evaluating Pipeline Defects*.
4	**REPAIR** defects in accordance with *SOP HLI.05 Pipeline Repair*, as applicable.

CAUTION: To mitigate corrosion growth, defects **MUST** be recoated following evaluation. Minimal surface preparation and a temporary coating system **IS** an acceptable practice to recoat defects following evaluation until a permanent coating system can be installed.

7.3 Evaluation of Inspection Results

Operations Personnel uses the following steps to evaluate inspection results.

Step	Activity
1	**RANK** coating conditions per *Appendix B Classification of Coating Inspections* and **INCLUDE** a detailed descriptions of any area requiring remedial action..

NOTE: Coating conditions are rarely uniform for an entire site/location. The use of multiple coating conditions cases (*Appendix B)* is encouraged to provide a more complete description of a site/location coating conditions. Comments, supplemented with photographs explaining the multiple rankings are required.

Step	Activity
2	**QUANTIFY** the coating failure by percent of bare pipe. **RECORD** percent coating failure in corrosion database.

NOTE: Quantifying is done to assist operations in determining the amount of coating repair needing to be completed.

Step	Activity
3	**DETERMINE** if the service life of the existing coating system can be extended through spot repair or maintenance painting.
4	**EVALUTE** whether the existing coating system will provide adequate protection to limit corrosion activity to a uniform light surface oxide and not affect the safety or integrity of the metallic asset before the next inspection.
5	**DEVELOP** a list of assets requiring remedial action. **INCLUDE** pictures and a brief scope of required action.

WARNING: Coating conditions with a Case 5, 6, or 7 classification require coating remediation/rehabilitation action.

Step	Activity
6	**DEVELOP** a list of assets not requiring remedial action but the life of the existing coating system could be extended through maintenance coating.
7	**DEVELOP** a list of assets along with a scope of work and time frame to evaluate areas requiring specialized equipment to perform a defect evaluation. A pressure reduction may be required until the defect can be evaluated.
8	**REVIEW** inspection results, requests for specialized equipment, and recommendations with the Operations Manager, and Corrosion Specialist.
9	**DEVELOP** a remedial action plan in accordance with *SOP D.40 Corrosion Control Remedial Action* for all projects requiring coating remediation.

7.4 Reporting

Operations Personnel uses the following steps to document inspection results.

Step	Activity
1	**DOCUMENT** coating evaluations including classifications determined using *Appendix B Classification of Coating Inspections* and recommended actions in the applicable electronic database.

NOTE: Documentation for Class 4 classification shall include the following:

- Corrosion Technician, Corrosion Specialist and OM agreement of remaining coating/light surface oxide, providing adequate corrosion protection to not affect the safety or integrity of the metallic asset until the next evaluation period.
- Summary of cumulative experience utilized to make determination.
- Inspection frequency required to verify corrosion control effectiveness of remaining coating / light surface oxides.

Step	Activity
1	**DOCUMENT** defect evaluations in the applicable electronic database.
2	**DOCUMENT** coating repairs in the applicable electronic database.
3	**DOCUMENT** remedial action plan using the applicable form(s) in accordance with *SOP HLD.40 Corrosion Control Remedial Action.*

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:

- Corrosion Database

- Pipe Inspection Database (GForms)
- D.40.A Remedial Action Report

9.0 References

HLA.01 Glossary and Acronyms
HLD.40 Corrosion Control Remedial Action
HLD.47 Evaluation of Remaining Strength of Pipe with Metal Loss
HLI.05 Pipeline Repair
HLI.06 Evaluating Pipeline Defects

Appendix A: OQ Task Requirements

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Inspection of the Application of Above or Below Ground Coatings	PLOQ402
Demonstrate how to Repair Small Holidays on New or Existing Coatings (above or below grade)	PLOQ403
Visual Inspection for Atmospheric Corrosion	PLOQ417

Appendix B: Classification of Coating Inspection

CASE	DESCRIPTION	ACTION
Case 1	Coating system intact. No indications of corrosion. Experience in Area indicates coating will perform adequately until next inspection period.	No action required.
Case 2	Coating system is greater than 95% intact except for the following:	No remedial action required; however, maintenance of the

CASE	DESCRIPTION	ACTION
	• Sharp edges inadequately striped; • Wrench marks; • Bolt heads • Minor coating imperfections Minor rust bleed may be present but no indications of detrimental corrosion. Experience in Area indicates coating will provide adequate corrosion protection and not affect the safety or integrity of the metallic asset before the next inspection.	coating system to include spot repairs of sharp edges or filling flanges will extend the service life the coating system and maintain aesthetics. ***Verify whether coating applicator warranty period is in effect, as such defects are common on new paint projects and are often covered under warranty.***
Case 3	Degradation of topcoat but primer and/or intermediate coat intact. Minor rust bleed may be present at isolated areas but no indications of detrimental corrosion. Experience in Area indicates coating will provide adequate corrosion protection and not affect the safety or integrity of the metallic asset before the next inspection.	No remedial action required; however, maintenance of the coating system to include spot repairs and/or application of a UV resistant topcoat will extend the service life of the coating system and maintain aesthetics.
Case 4	Degradation of topcoat, intermediate coat, and/or primer. Coating has degraded to allow widespread light surface oxides, pin-pointing and/or rust bleed. Corrosion is limited to a light surface oxide with no indications of pitting. Experience in the Area indicates the remaining coating/light surface oxide will provide adequate corrosion protection and not affect the safety or integrity of the metallic asset before the next inspection.	No remedial action required; however, maintenance of the coating system to include spot repairs and/or application of a UV resistant topcoat will extend the service life of the coating system and maintain aesthetics. ***Corrosion Technician, Corrosion Specialist, and Operations Manager must document agreement with all Case 4 classifications and determine if a more frequent monitoring interval is required.***
Case 5	Damaged coating on piping in an offshore splash zone, onshore water-to-air interface, or soil-to-air interface. Damaged coating includes any condition, to include natural degradation which can compromise the ability of the coating system to electrically isolate pipeline steel from an electrolyte.	Requires coating remediation/rehabilitation regardless of corrosion activity. Repair or replace existing coating system per Company Standards.

CASE	DESCRIPTION	ACTION
Case 6	Any corrosion other than light surface oxide found on piping due to missing, degraded, or failed atmospheric coating systems not classified as Case 1-5. NOTE: This also applies to any tank/piping system containing regulated materials such as brine, hydrocarbons, or glycol.	Requires coating remediation/rehabilitation. Repair or replace existing coating system per Company Standards.
Case 7	Any corrosion not classified as Case 1 – 6 due to missing, degraded, or failed atmospheric coating systems.	Requires coating remediation/rehabilitation. Repair or replace existing coating system per Company Standards. ***Corrosion Technician, Corrosion Specialist, and Operations Manager must document a course of action with all Case 7 classifications.***

ENERGY TRANSFER

Wet Magnetic Particle Inspection

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	Procedure No.: HLD.45	
49 CFR 195.587	***Effective Date: 04/01/18***	**Page 1 of 5**

1.0 Purpose

This Standard Operating Procedure (SOP) describes the method of Wet Magnetic Particle Inspection (MPI) for locating surface breaking indications on line pipe and other ferrous components.

2.0 Scope

This SOP outlines the purpose for performing a MPI in-house by company employees is to inspect for the presence of surface breaking indications on the pipe. After these indications have been identified they must be evaluated to determine their actual characteristics. Not all indications will be cracks or other injurious imperfections.

3.0 Applicability

This SOP applies to the detection of surface breaking indications on the surface of line pipe or other ferrous components using wet magnetic particle inspection.

4.0 Frequency

As required: when inspecting for surface breaking indications.

5.0 Governance

The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician	Operations Manager	Area Director/Division Vice President

6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP* HL*A.01 Glossary and Acronyms*.

Terms	Definitions
Stress Corrosion Cracks	SCC is caused by a number of environmental factors. SCC is the generic term that describes cracking where the surrounding environment, the pipe material, and stress act together to form a crack. SCC is typically seen as a cluster of small cracks on the pipe's exterior surface. Over time these small cracks can coalesce (grow together) into larger cracks and result in eventual failure.

Terms	**Definitions**
Surface Breaking Indications	Not all features that exhibit crack like features are cracks. Proper analysis is needed to categorize these features as cracks.
Mechanical Damage Cracks	When a pipeline is struck by a back-hoe or other means, there are three types of damage that can occur to the pipe: • Dents - where the pipe is deformed dimensionally without metal loss • Gouges - where the pipe wall is removed or damaged, resulting in metal loss • Cracks formed due to the high-localized stress areas. While dents and gouges are readily apparent based on visual inspection, cracks may or may not be visible without the MPI technique

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7.0
Wet Magnetic Particle Inspection

This SOP contains the following sections:

- Materials/Tools
- Cleaning
- White Contrast Paint
- Magnetization
- Evaluation of Indications
- Repair

7.1
Materials/Tools

Operations Personnel uses the following materials and tools for magnetic particle inspection:

- A magnetizing yoke (powered by 115 VAC)
- White Contrast Paint – This is a paint specially formulated for MPI. White Contrast Paint is applied to the component surface prior to magnetic particle inspection in order to provide a contrast between the white painted surface and the black ferro-magnetic particles
- Liquid Bath – Magnetic Particle Inspection materials consist of finely divided ferro-magnetic particles suspended in a carrier fluid
- AC power source to energize the magnetizing yoke
- Abrasive blaster
- Blast Media – A mixture of Walnut shells and abrasive grit are the preferred abrasive blast media. Other abrasive materials approved by the Director of Pipeline Integrity may be used
- If blasting is not available, use greaseless (non-petroleum based) solvent to clean the pipe. Typical solvents include acetone, alcohol, etc.

7.2 Cleaning

Operations Personnel follows the procedure below for cleaning.

Step	Activity
1	**CLEAN** any coating, dirt, oil, or grease from the inspection area by abrasive blasting to a NACE #3 commercial metal blast standard or solvent clean and hand wire brush when inspecting in-service pipe or pipe components that are coated.
2	**CLEAN** any dirt, oil, or grease from the inspection area by using a greaseless solvent when inspecting pipe or components that have not been coated.

NOTE: Power brushing is not allowed. This process tends to mark or distort the pipe surface and reduce the ability to detect a crack.

7.3 White Contrast Paint

Operations Personnel follows the procedure below for white contrast paint application.

Step	Activity
1	**SPRAY** a single coat of paint in a uniform manner over the entire inspection area.
2	**TAKE CARE** to apply a light coat, as excessive paint could fill the cracks and make their detection more difficult.

7.4 Magnetization

Operations Personnel follows the procedure below for magnetization.

NOTE: When the yoke is placed on the pipe and turned on, lines of magnetic flux flow from the South to North Pole of the magnetic yoke.

Step	Activity
1	**APPLY** a liberal amount of the solution to an area slightly larger than a circle that would contain the two poles of the magnet.

NOTE: Indications that are perpendicular to the lines of flux (perpendicular to the yoke's handle) and up to 45° should be revealed.

Step	Activity
2	After the first inspection is made, **TURN OFF** the yoke and **ROTATE** 90°. **REPEAT** the process for the same inspection area.

NOTE:	This step is necessary because indications that are parallel to the lines of magnetic flux in the first inspection will not be seen until the second inspection is conducted.

Step	Activity
3	**REPEAT** this process as required to address the entire inspection area.

7.5 Evaluation of Indications

Operations Personnel follows the steps below for evaluation of indications.

Step	Activity
1	**CHARACTERIZE** a fracture type discontinuity with sharp tips.

NOTE:

- Where indications are present, the defects will appear as an accumulation of magnetic powder.
- Not all indications are cracks.

Step	Activity
2	**USE** judgment to determine whether an indication is a crack or some other imperfection.
3	**CONTACT** Pipeline Integrity Engineer for guidance on evaluation of indications.
4	**CONSULT** a company or experienced third-party metallurgist for guidance in this determination.

NOTE:	MPI for girth welds, longitudinal line pipe welds, and fillet welds will be performed by an OQ qualified third party inspector.

Crack Type	Location	Length	Shape/Appearance
Stress Corrosion Crack	Parallel to Pipe Axis; may or may not be primarily adjacent to seam weld	< 1" <	Branched or jagged; singly or colonies; linked with adjacent cracks
Hydrogen/Material Defects	Anywhere on pipe	Typically ¼" – 4"	Single cracks; may have steps or be jagged
Hook Cracks	< ½ " from ERW seam	Any length	Continuous or intermittent, approximately constant distance from seam weld
Laps, slivers and scabs	Anywhere on pipe	Any length or size	Any orientation; can be curved; may have upturned edge. Generally very shallow.
Roll Marks	1" – 6" from ERW seam	Any length	Continuous or intermittent. May extend full length of pipe joint.

7.6 Repair

When evaluations confirm the presence of cracks, make repairs in accordance with *SOP HLI.05 Pipeline Repair* and *SOP HLI.06 Evaluating Pipeline Defects.*

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:

Document inspection results in the Pipe Inspection Database in accordance with *SOP HLD.35 Buried Pipe Inspections*.

9.0 References

HLI.05 Pipeline Repair
HLI.06 Evaluating Pipeline Defects
HLD.35 Buried Pipe Inspections

Appendix A: OQ Task Requirements

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Utilize Wet Magnetic Particle Inspection to identify surface breaking indications on line pipe and other ferrous components (PEOQ, CORR1).	PLOQ205
Measure and evaluate pipeline defects	PLOQ418A

ENERGY TRANSFER

Evaluation of Remaining Strength of Pipeline Metal Loss

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Code Reference :	**Procedure No.: HLD.47**	
49 CFR: 195.585, 195.587	***Effective Date: 04/01/18***	

1.0 Procedure Description

This Standard Operating Procedure (SOP) describes details of evaluation methods used to determine the remaining strength of ductile carbon steel pipe with metal loss.

2.0 Scope

RSTRENG is a computer program used to determine the remaining strength of corroded pipe. This SOP describes how to obtain the information RSTRENG needs to function correctly. See the RSTRENG manual for information on running the program.

3.0 Applicability

This SOP applies to those company facilities described below:

- Are limited to metal loss on pipeline steels categorized as ductile carbon steels or high-strength, low-alloy steels.
- Apply only to metal loss defects in line pipe with relatively smooth contours, which cause low stress concentration (e.g., electrolytic or galvanic corrosion, loss of wall thickness due to erosion, smooth grinding repair).
- Are not to be used to evaluate selective (i.e., grooving) corrosion in the bond line of an Electric Resistance Welded (ERW) or flash-welded line pipe material.
- Contain criteria based only upon the ability of the pipe to maintain structural integrity under internal pressure. These guidelines should not be used when pipe is subject to significant secondary stresses (e.g., axial bending or thermal stress combined with internal pressure).

4.0 Frequency

As required: Perform an analysis of pipelines containing metal loss.

5.0 Governance

The following table describes the responsibility, accountability, and authority of the operations described in this SOP.

Function	Responsibility	Accountability	Authority
All Tasks	Corrosion Technician/Pipeline Integrity Engineer	Operations Manager	Area Director / Division Vice President

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6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP HLA.01 Glossary and Acronyms*.

Terms	Definitions
Modified B31G 0.85dL Area Method	Method used to determine acceptability of metal loss defect based on maximum depth and total length. Allowable length tables are generated using this method. This method is the basis for the Case 2 RSTRENG calculation.
Modified B31G “Effective Area” Method	Method used to determine acceptability of metal loss defect based on multiple depth measurements at increments along the length of the defect. This method is the basis for the Case 1 RSTRENG calculation.

7.0 Evaluation of Remaining Strength of Pipeline Metal Loss

One of two methods determines pipe metal loss and remaining strength: the modified B31G 0.85dL Area Method or the Modified B31G “Effective” Area Method (RSTRENG). The following sub-procedures describe these methods and how to evaluate strength of pipeline metal loss:

- Application of Methods
- The Modified B31G 0.85dL Area Method
- The Modified B31G Effective Area Method (RSTRENG)
- Evaluation of Metal Loss in Welds

For instructions on using the RSTRENG computer program, refer to the AGA-PRC Project PR-805 *A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe* report and the Software User’s Manual.

CAUTION

> If any pit depth in an area of metal loss is equal to or exceeds 80% of the actual wall thickness, repair or replace the section. However, evaluate metal loss in order to establish the safe operating pressure.

7.1 Application of Methods

The modified B31 G0.85dl area method provides the initial test that determines which method to apply. If the pipeline does not pass the criteria for that method, then the modified B31G Effective Area method is applied.

> **NOTE:** Apply B31G Effective Area (RSTRENG) evaluation when collectin ILI anomaly response or as directed by integrity engineer.

These metal loss evaluation methods use the semi-empirical fracture mechanics equation that follows. The result of the calculation below, or the appropriate metal loss evaluation guideline tables that the B31G 0.85dL area method generate, is then used to determine metal loss.

$$SF = \check{S} * [(1-A/A0) / (1-(A/A0)\ (MT-1))]$$

WHERE:

MT=	Folias factor, a function of L, D, and t
SF =	Hoop stress level at failure, psi
Š =	Flow stress, a property of the material related to its yield strength, psi
A =	Profile area of crack or defect in the longitudinal plane through the wall thickness (e.g., 2/3 (d*L) for B31G or 0.85 (d*L) for Modified Battelle), in^2
A0=	L * t, in^2
L =	Axial extent of the defect, inches
T =	Wall thickness of the pipe, inches
D =	Diameter of the pipe, inches

The result of the calculation above or the appropriate metal loss evaluation guideline tables, the B31G 0.85dL area method, is then used to determine metal loss.

For pipes suspected to behave in a brittle manner, evaluate metal loss with the B31G method with the approval and supervision of the Pipeline Integrity Group. This SOP does not describe this method.

7.2 Modified B31G 0.85dL Area Method

Operations Personnel evaluates the extent of a metal loss defect by preparing the section of pipeline, measuring the depth of metal loss, then utilizing table(s) of allowable lengths following the steps described in this section.

Step	Activity
1	**DETERMINE** other considerations before disturbing the area of interest, including the need to: • **EVALUATE** any corrosion byproducts. • **ASCERTAIN** the activity of corrosion or the possible influence of bacteria on the corrosion.
2	**EXPOSE** the metal surface of the pipeline. Remove any coating or dirt if necessary.

CAUTION:	Selection of cleaning methods for very deep corrosion pits is based upon safety considerations. A reduction in operating pressure may be necessary.

Step	Activity
3	**VERIFY** that the affected area is wire brushed, power brushed, or abrasive blasted as necessary (or practical) to enable proper measurement of the metal loss dimensions.
4	**MARK OFF** the corroded area with a paint pencil or magic marker in 1" increments through the corroded area to be evaluated. **REPORT** the depth in mils (XXX mils, 1 mil = .001 inches).
5	**READ** and **RECORD** the deepest pit in the 1" section under investigation. When taking the pit depths, **KEEP** the measurements within a 7" to 9" corridor (about the distance from the tip of the thumb to the tip of the little finger with the hand spread).
6	If the defect has 80% or greater penetration, **MAKE** either a temporary or permanent repair per pipeline *SOP HLI.05 Pipeline Repair*. If the defect has less than 80% penetration, **CONTINUE** to step 7.
7	**MEASURE** the length of metal loss as projected along the longitudinal axis of the pipe. **REFER** to Figure 1. If adjacent metal loss defects are separated by less than 1 inch of sound metal axially and 6 x w.t. of sound metal circumferentially, **CONSIDER** the adjacent defects as one defect.

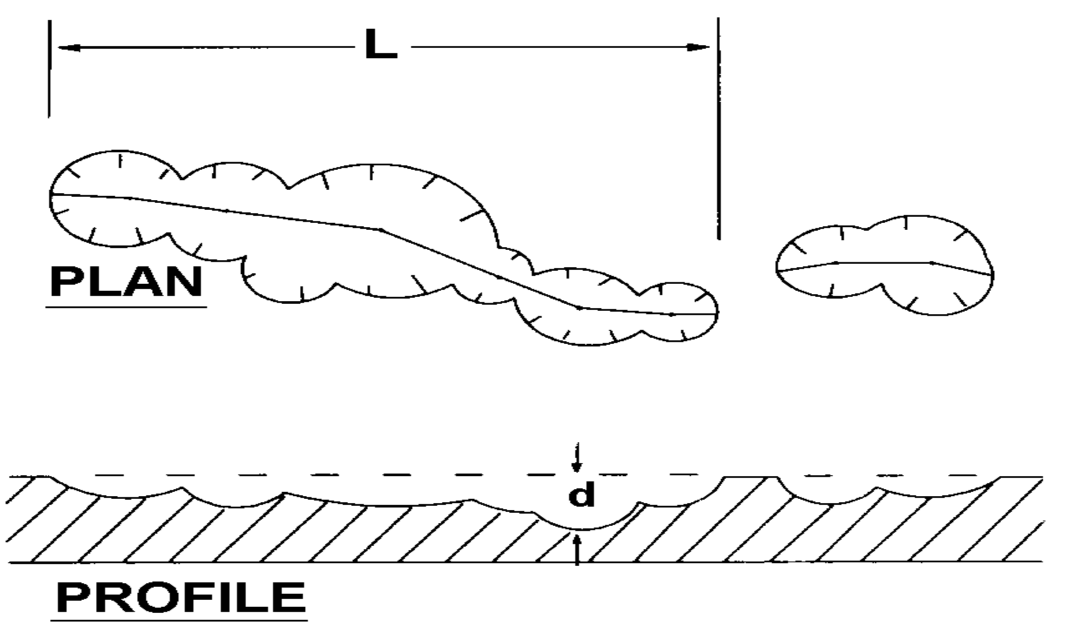

Figure 1

Step	Activity
8	**EVALUATE** corrosion defect using allowable length tables.

NOTE:
- Allowable length tables can be obtained for common pipe grades, diameters, and wall thicknesses on the Corrosion Services website. Hard copies are also available from your Corrosion Specialist.
- Contact Corrosion Specialist if required grade diameter wall thickness is not listed on the website.
- Hard copies of common pipe grades, diameters, and wall thicknesses are also available.

Step	Activity
9	If the measured length of the defect is shorter than the allowable length, **RECOAT** and **BACKFILL** the carrier pipe unless other reasons are found for making a repair.
10	If the length of the defect is greater than the allowable length, **USE** the Modified B31G "Effective Area" method described in Section 7.3.

7.3 Modified B31G "Effective Area" Method

The Modified B31G "Effective Area" method uses detailed measurements of the metal loss in successive calculations to predict a minimum failure pressure for an area of metal loss based upon its "effective" area (the result of an iterative calculation procedure along the metal loss profile). This method typically reduces the over conservatism of the Modified B31G 0.85dL Area method, which results from assuming that the defect has 85% area loss.

NOTE: For Pit Depths ≥ 80% of the wall thickness, this criterion considers the possible rupture of a section of corroded pipe and does not account for the possibility that a defect may leak.

7.3.1 Minimum Metal Loss Depths

For pipelines operating at a stress level equal to or less than 72% of SMYS, a defect with up to 20% penetration will not fail the RSTRENG equation at any length, based upon nominal wall thickness.

7.3.2 Measurement of External Metal Loss

Use the following criteria for the measurement of external metal loss when using the modified B31G "Effective Area" method.

Step	Activity
1	**MEASURE** the axial length of a metal loss defect (L) as the total length of contiguous metal loss as projected along the longitudinal axis of the pipe, measured in increments from upstream to downstream. (**SEE** Figure 2 and Figure 3.)
2	**CONSIDER** adjacent metal loss defects as one defect if they are separated by less than 1 inch of sound metal axially and 6 x w.t. of sound metal circumferentially.
3	**REPORT** defect length in inches and decimals (X.XXX inches).

NOTE: The dashed line in Figure 5 illustrates the manner by which RSTRENG divides the defect into incremental values of "A" for calculating metal loss for the modified B31G "Effective Area" method. This results in an assumed metal loss which is most representative of the actual metal loss.

Step	Activity
4	**EVALUATE** corrosion defects to a maximum length of one pipe diameter either direction from center of deepest pit. **PERFORM** additional evaluations as required for any metal loss located outside this area.

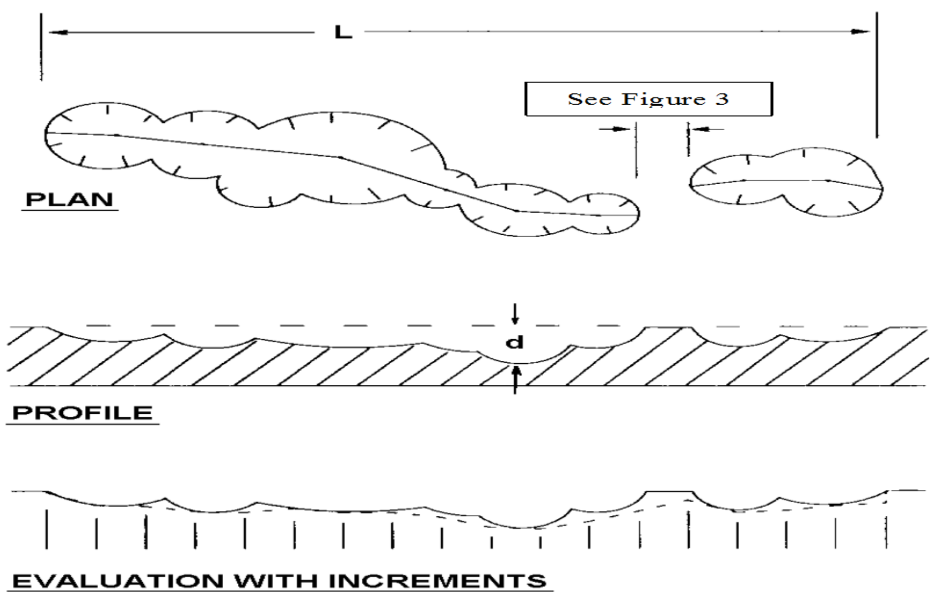

Figure 2

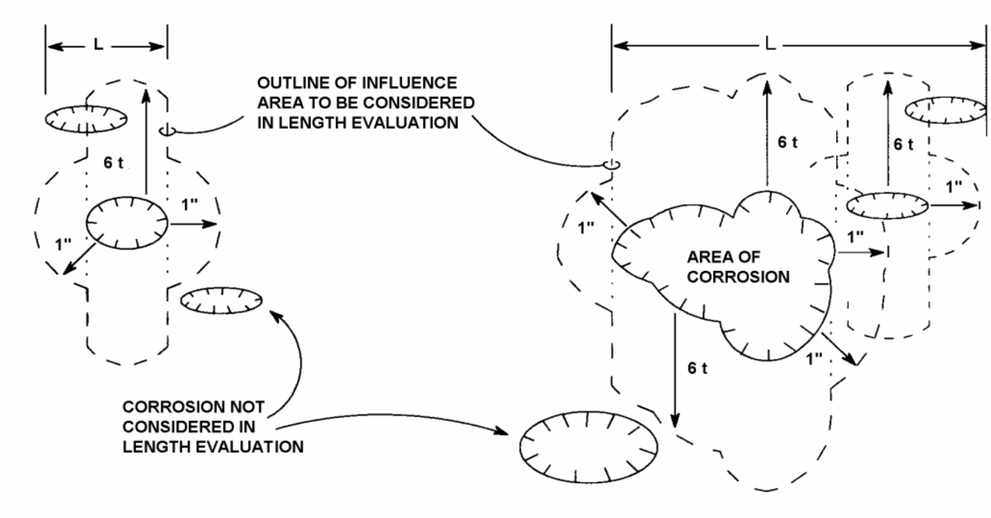

Figure 3

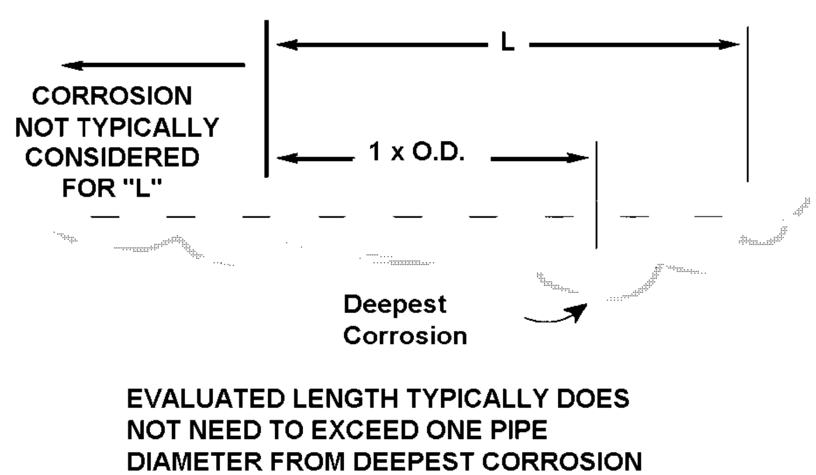

Figure 4

7.3.3
Input Data into RSTRENG

Operations Personnel follows the procedure below to input data into RSTRENG.

Step	Activity
1	**USE** the following increments for metal loss of length “L,” unless otherwise approved by the Corrosion Specialist.

Length of Metal Loss	*Increment*
L ≤ 3”	1/4”
3” < L ≤ 6”	1/2”
L > 6”	1”

Step	Activity
2	**ENTER** pipe diameter, wall thickness, and SMYS into the appropriate fields of the program. For the wall thickness value, **USE** the lowest value of actual wall thickness measured from ultrasonic thickness readings taken in all directions around the defect as the basis of any calculations.
3	**SELECT** the uniform spacing option and **RECORD** the depth of the metal loss defect (d) that is the maximum measurable depth of metal loss at any point within each increment (see Figure 5).

NOTE:

- Measurement technique within the computer program refers to either taking metal loss depth measurements or remaining wall thickness measurements. When remaining wall thickness measurements are entered, these measurements are subtracted from the wall thickness value and immediately converted by the computer program to metal loss depths.
- The axial distance between the successive depth measurements may vary even though the increments are uniform. When making the measurements, it is not necessary to measure the depth at an exact distance from the previous measurement. Metal loss depth is normally reported in mils (XXX mils).

Step	Activity
4	For extreme circumstances due to the complexities involved in selection of appropriate increments, **CHOOSE** the irregular spacing option. **CONSULT** the Corrosion Specialist prior to applying the irregular increment spacing option.

NOTE: In some cases (grandfathered pipe), MAOP will exceed design pressure calculations. The RSTRENG program will generate a warning that must be acknowledged to use the more conservative MAOP value. When this error appears contact the Pipeline Integrity Engineer to determine further actions.

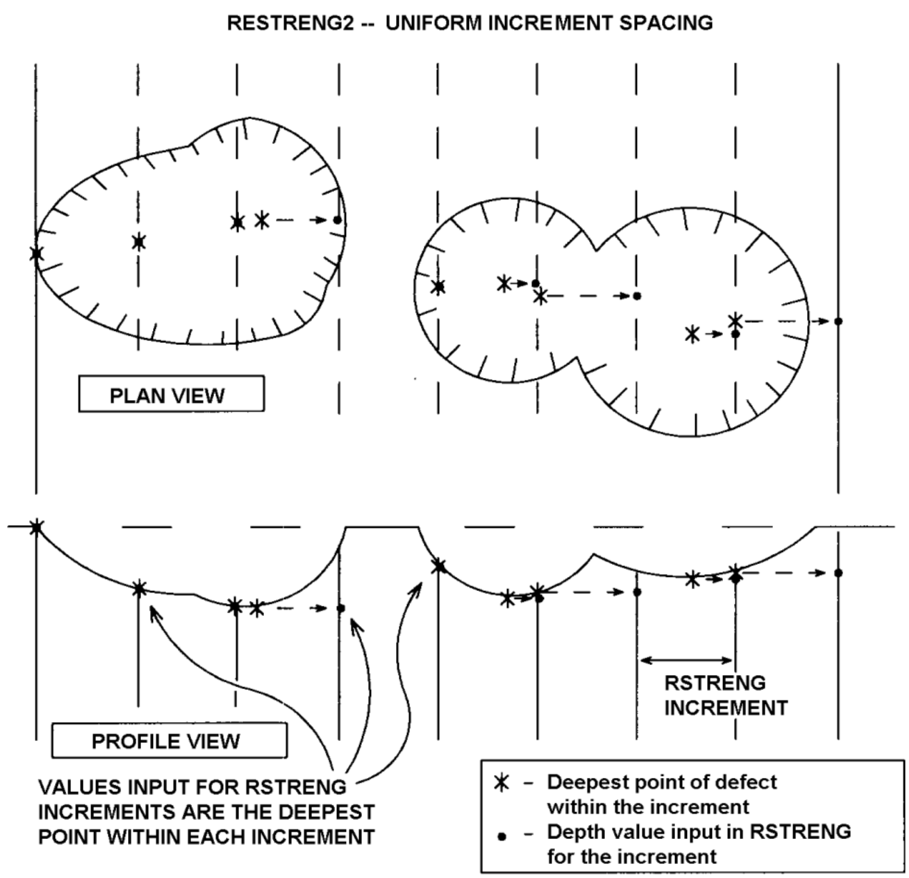

Figure 5

7.3.4 Determine Results

Operations Personnel is responsible for determining the results.

Step	Activity
1	**COMPARE** the output ("Calculated Pressures/Print") of "Case 1" safe maximum pressure to the MOP.
2	**REPAIR** per the requirements of *SOP HLI.05 Pipeline Repair* if Case 1 pressure is less than the MOP.
3	**COAT** and **BACKFILL** if Case 1 pressure is greater than MOP, unless other reasons are found for making a repair.

NOTE: Contact Pipeline Integrity Engineer if Case 1 pressure is equal to MOP. Pipeline Integrity Engineer determines if a repair is required

7.4 Evaluation of Metal Loss in Welds

Operations Personnel uses the following procedures to evaluate metal loss in welds.

7.4.1 Evaluation of Metal Loss in Longitudinal Welds

Operations Personnel uses the following procedure to evaluate metal loss in longitudinal welds.

Step	Activity
1	**EVALUATE** metal loss in DSAW longitudinal seams using the effective area method. **SUBTRACT** the height of the weld cap from the measured metal loss depth to **DETERMINE** the metal loss depth.

NOTE: Example: If the metal loss depth is measured to be 100 mils, relative to the top of the weld cap, and the weld cap is 40 mils above the pipe outer diameter, then a value of 100 - 40 = 60 mils should be used as the metal loss depth in the evaluation criteria.

Step	Activity
2	**REPAIR** or **REPLACE** metal loss in the longitudinal seams for all pipe types that are not DSAW, regardless of the severity of the metal loss.
3	**REPAIR** or **REMOVE** metal loss characterized as “grooving” along the longitudinal seam.

7.4.2 Evaluation of Metal Loss in Girth Welds

Operations Personnel uses the following procedure to evaluate metal loss in girth welds.

Step	Activity
1	**EVALUATE** metal loss in all girth welds except acetylene using the effective area method. **SUBTRACT** the height of the weld cap from the measured metal loss depth to **DETERMINE** the metal loss depth.

NOTE:	Girth welds that are expected to behave in a brittle manner should be evaluated with the B31G method (not described in this SOP) as directed by the Director of Technical Services.

Step	Activity
2	**REPAIR** or **REPLACE** metal loss in the girth weld for all acetylene welded pipe, regardless of the severity of the metal loss.

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:

Record evaluation results for above and below ground piping in the Pipe Inspection database.

9.0 References

AGA-PRC Project PR-805: A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe
HLI.05 Pipeline Repair
RSTRENG© Software User's Manual

Appendix A: OQ Task Requirements

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Demonstrate proper use of pipe thickness gauge (Ultrasonic)	PLOQ008
Visual Inspection of Buried Pipe and Components When Exposed	PLOQ401
Visual Inspection for Internal Corrosion	PLOQ414
Visual Inspection for Atmospheric Corrosion	PLOQ417
Measure and evaluate pipeline defects	PLOQ418A

ENERGY TRANSFER

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

PHMSA Mainline Valve Inspection, Maintenance and Operation

Code Reference:	**Procedure No.: HLM.01**	
49 CFR: 195.258, 195.420, 195.260, 195.116	**Effective Date:** ***04/01/18***	**Page 1 of 11**

1.0 Procedure Description

This Standard Operating Procedure (SOP) describes the activities associated with Mainline valve inspection, maintenance and operation.

2.0 Scope

This SOP establishes the requirements for PHMSA valve, valve operator and Remote Control Valve (if applicable) inspection, maintenance, and operation in accordance with company and federal regulations.

3.0 Applicability

This SOP applies to operating personnel that are required to inspect, maintain and operate valves in accordance with company and federal regulations.

4.0 Frequency

Twice each calendar year, not to exceed 7 ½ months – Inspect, maintain and operate the valves and valve operators. See Sections 7.1 thru 7.3

Annually, Once each calendar year, not to exceed 15 months. – Calibrate, inspect, maintain and operate valve operators and RCV valves – calibrate pressure and temperature transmitters. See Sections 7.1 and 7.4

Annually, Once each calendar year, not to exceed 15 months. – Check, inspect, maintain and operate valve operators and RCV valves – check pressure and temperature transmitters for reading accuracy. See Sections 7.1 and 7.5

> **NOTE:** The two annual valve operator and RCV tasks (Calibrate and Check) are scheduled six months apart (can be with the valve inspection) to conduct two RCV tests per year.

5.0 Governance

The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Functions	Operations Personnel	Operation Manager	Director of Operations

6.0 Terms and Definitions

Terms associated with this SOP and the definitions for each valve that is necessary for the safe operation of its pipeline follow in the table below. For general terms, refer to *SOP* HL*A.01 Glossary and Acronyms*.

Terms	Definitions
Mainline Valves	• <u>Pipeline</u>: Block (Main), Cross-over and Lateral Tap valves. • <u>Pump station</u>: Suction, Discharge, Isolation, Launcher, Receiver and By-Pass valves. • <u>Meter station</u>: Inlet, Outlet, MOP Protection (other than reliefs - Refer to *SOP HLM.05Relief Valve Testing Inspection and Maintenance)* and Bypass valves.
Remote Control Valve (RCV)	Remote Controlled Valves (RCV) are remotely operated valves initiated by a person in the Liquids Control Center (open or closed as required) and inspected, maintained and operated as required by this SOP.

7.0 Mainline Valve Inspection, Maintenance and Operating Procedures

A verified OQ qualified member(s) of operations personnel or OQ verified third party contractor(s) performs all inspections, maintenance and operations as described in this SOP.

Mainline Valve and valve operator Inspection, Maintenance, and Operation – perform the following common steps for procedures described in each section 7.1 thru 7.3.

WARNING:

- Manual operation may yield a safety hazard due to the engagement of the hand whe shaft during power operation. Remove and store hand wheels where possible.
- Refer to SOP HLB.06 Hazardous Energy Control (Lockout / Tagout) and Safe Procedure S-230 Hazardous Energy Control (Lockout / Tagout)) prior to starting t procedure.

CAUTION: Refer to Safety Procedure S-060 Confined Space Entry regarding work permits to determine if the valve is in a confined space when valves are in boxes, sumps, pits, or similar locations.

CAUTION: Refer to Safety Procedure S-005 General Safety and Incident Prevention prior to starting this procedure. The use of Personal Electronic Devices (PEDs) by pipeline employees is discouraged while working in or around a hazardous atmosphere. Most PEDs are not intrinsically safe and could potentially be an ignition source.

Step	Activity
1	**NOTIFY** Liquid Control Center and upstream and downstream operations prior to inspecting, maintaining and operating any valve that may significantly affect system flow. **NOTIFY** those responsible for measurement or plant facilities if the inspection of a valve might affect the normal operation of those facilities.
2	If it becomes necessary to manually operate any operator equipped with a hand wheel or hand pump, **SHUT OFF** the power or **CLOSE** the power gas supply lines connecting to the operator and **BLEED OFF** the pressure on the supply lines prior to installing the hand wheel/pump handle. **REMOVE** the hand wheel/pump handle from the operator prior to reopening the power gas supply lines.

Step	Activity
3	**VERIFY** hand wheels used in conjunction with permanently mounted automatic and manually activated operators do not have any protrusions from the outer rim including those designed to aid manual operations.
4	Immediately **REPORT (**within 24 hours**)** issues with the inspection, maintenance and operation (that has not been corrected) for any emergency valve to the Operations Manager/Supervisor. Contingency plans may need to be made for addressing the valve issue until repairs can be made.
5	**NOTIFY** Liquid Control Center and Upstream / Downstream operations when the valve, operator and RCV inspection, maintenance and operation is completed. Verify final position and pressures with Liquid Control Center (if applicable).

7.1 Mainline Valve Inspection

Follow the steps below for mainline valve and valve operator inspections.

Step	Activity
1	**VERIFY** that the valve number is secure and legible and matches the applicable emergency drawings and the records numbers.
2	Visually **INSPECT** the valve, valve operator and related equipment. **EVALUATE** the overall condition of the equipment and the maintenance that may be required.
3	**INSPECT** the valve and valve operator for evidence of leaks.
4	**INSPECT** valve boxes, where applicable, and **NOTE** the condition.
5	**VERIFY** the condition and operation of the lock on the valve. Each valve must have a locking device to protect against unauthorized operations and vandalism unless enclosed by locked security fencing.

7.2 Mainline Valve Maintenance

Follow the steps below for mainline valve and valve operator maintenance.

Step	Activity
1	**REFER** to the applicable manufacturer's manuals and the company guidelines for valve and valve operator maintenance and troubleshooting.
2	**PERFORM** normal valve maintenance as directed by the valve manufacturer.
3	**PERFORM** normal valve operator maintenance as directed by the valve operator manufacturer.
4	**WINTERIZE** valves, valve operators and related equipment that may be subjected to freezing temperatures, where applicable. **INCLUDE** draining of the valve bodies, gear-boxes, and any other places where water may accumulate as part of winterizing.

7.3 Operate Mainline Valves

Follow the steps below for operating valves and valve operators.

Step	Activity
1	**OPERATE** the valve and valve operator as per the instructions provided by the manufacturer. If possible, **TEST** end of travel limits (stops) for proper valve travel. If applicable, **CHECK** all tubing, fittings and appurtenances for leakage or damage. **CHECK** end devices and electrical connections for corrosion and loose connections.
2	**OPERATE** the valve partially to validate the operation when it is not possible to stroke the valve 100% due to product flow conditions. **RETURN** valve to the proper position.

CAUTION: MONITOR and **PROTECT** the applicable MOP(s) when operating valves that could impact the MOP of connecting pipelines / facilities.

Step	Activity
3	Immediately **INVESTIGATE** and **CORRECT** binding, dragging, or excessive force required to operate the valve within 30 days. Report any unresolved issues to Operations Manager / Supervisor for resolution and direction.
4	When the valve operation is complete, **RETURN** the valve to the As Found operating position.
5	**RESTORE** valve security after inspection.
6	**RECORD** valve operation (As Found position - As Left position and Full or Partial valve operation) using the proper documentation method (Refer to Section 8.0)

7.4 PHMSA RCV Valve Calibration, Inspection, Maintenance and Operation

Some mainline valves may be equipped with Remote Controlled Valve (RCV controls) for remote operation by a person in the Liquid Control Center. These RCV valve controls require additional calibration, inspection, maintenance and operation.

RCV Valve and valve operator Calibration, Inspection, Maintenance, and Operation – perform the common steps found in Section 7.1 and the following steps described in this section.

CAUTION: MONITOR and **PROTECT** the applicable MOP(s) when operating valves that could impact the MOP of connecting pipelines / facilities.

NOTE: If a service disruption occurs, test the controls and operator systems separate to the degree where a service disruption will not occur.

Step	Activity
1	Visually **INSPECT** the valve, valve operator and RCV related equipment. **EVALUATE** the overall condition of the equipment and the maintenance that may be required.
2	**INSTRUCT** the Liquids Control Center to command the RCV valve to close. If flow conditions do not allow closure of the valve make sure the Liquids Control Center interrupt command stops the valve travel after 5-10 degrees of valve operation – verify the Liquids Control Center loss of the open limit switch signal. **BE PREPARED** to manually stop valve travel. Have Liquids Control Center to command the valve to open. Observe the proper response of the RCV remote commands and valve position indication.
3	**CONFIRM** the proper operation of the signal from the Liquids Control Center to the Remote Terminal Unit (RTU), the signal from RTU to valve operator, and feedback information to the Liquids Control Center.
4	For each pressure transmitter perform the following with approved test instrumentation: a. **CHECK** process instrumentation tubing, manifolds and fittings for leaks. b. **INSPECT** and **CHECK** end devices and electrical connections for corrosion and loose connections. c. **CHECK** transmitter and system power supplies to see if they are within the manufacturers published tolerance. d. **CALIBRATE** each transmitter at zero, mid span and full span. e. **CALIBRATE** and **RECORD** the “As Found” and “As Left” values for each transmitter at the current pipeline pressure or the transmitter’s mid-range pressure. f. **REPAIR or REPLACE** faulty components as required. Verify proper operation of each component and the RCV system after correction. Report any unresolved issues to Operations Manager / Supervisor for resolution direction.

Step	Activity
	g. **VERIFY** that the Liquids Control Center is reading the correct pressures and the Liquids Control Center readings are changing as expected.

7.5 PHMSA RCV Valve Check, Inspection, maintenance and Operation

Some mainline valves may be equipped with Remote Controlled Valve (RCV controls) for remote operation by a person in the Liquid Control Center. These RCV valve controls require additional inspection, maintenance and operation.

RCV Valve and valve operator Check Inspection, Maintenance, and Operation – perform the steps found in Section 7.1 and the following procedures described in this section.

CAUTION: MONITOR and **PROTECT** the applicable MOP(s) when operating valves that could impact the MOP of connecting pipelines / facilities.

NOTE: If a service disruption occurs test the controls and operator systems separate to the degree where a service disruption will not occur.

Step	Activity
1	Visually **INSPECT** the valve, valve operator and RCV related equipment. **EVALUATE** the overall condition of the equipment and the maintenance that may be required.
2	**INSTRUCT** the Liquids Control Center to command the RCV valve to close. If flow conditions do not allow closure of the valve make sure the Liquids Control Center interrupt command stops the valve travel after 5-10 degrees of valve operation – verify the Liquids Control Center loss of the open limit switch signal. **BE PREPARED** to manually stop valve travel. Have Liquids Control

Step	Activity
	Center to command the valve to open. Observe the proper response of the RCV remote commands and valve position indication.
3	**TEST** signal from the Liquids Control Center to the Remote Terminal Unit (RTU), the signal from RTU to valve operator, and feedback information to the Liquids Control Center.
4	For each pressure transmitter perform the following with approved test instrumentation: a. **CHECK** process instrumentation tubing, manifolds and fittings for leaks. b. **INSPECT** and **CHECK** end devices and electrical connections for corrosion and loose connections. c. **CHECK** transmitter and system power supplies to see if they are within the manufacturers published tolerance. d. **CHECK** each transmitter for accurate readings using approved instrumentation**.** e. IF the transmitter accuracy check in “d” above indicates a full transmitter calibration is required **- CALIBRATE** and **RECORD** the “As Found” and “As Left” values for the applicable transmitter at the current pipeline pressure or the transmitter’s mid-range pressure. f. **REPAIR or REPLACE** faulty components as required. Verify proper operation of each component and the RCV system after correction. Report any unresolved issues to Operations Manager / Supervisor for resolution direction. g. **VERIFY** that the Liquids Control Center is reading the correct pressures and the Liquids Control Center readings are changing as expected.

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:

- M.01.A Valve Inspection Report

Activity	**Reporting**
Acknowledge the requirements as outlined in this SOP have been completed. Record exceptions in the Remarks section of the form M.01.A. File Form M.01.A	Electronic Maintenance System M.01.A Valve Inspection
Acknowledge the requirements as outlined in the SOP have been completed. • Record valve position "As Found" • Record valve position "As Left" • Record valve operation as "Full" or "Partial"	Electronic Maintenance System M.01.A Valve Inspection
Record reason if valve position "As Left" is different than "As Found" File Form M.01.A	Electronic Maintenance System (Description Tab) M.01.A Valve Inspection

9.0 References

HLB.06 Hazardous Energy Control (Lockout / Tagout)

S-005 General Safety and Incident Prevention

S-230 Hazardous Energy Control (Lockout / Tagout)

S-060 Confined Space Entry

HLM.05 Relief Valves Testing Inspection and Maintenance

Appendix A: OQ Task Requirements

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task
Operating Pipeline Valves	PLOQ007
MOP - Monitoring and Protecting	PLOQ813
Inspect and Maintain Valves	PLOQ806
Commission and Maintain Plug Valve	PLOQ716A
Commission and Maintain Ball Valve	PLOQ716B
Commission and Maintain Gate Valve	PLOQ716C
Commission and Maintain Globe Valve	PLOQ716D
Repair Valves	PLOQ807
Commission and Maintain Pneumatic Actuator	PLOQ351
Commission and Maintain Electric Actuator	PLOQ0361
Commission and Maintain Hydraulic Actuator	PLOQ0371
Commission and Maintain Transducers and Transmitters Including RTU and PLC Functionality in Conjunction With Transducers and Transmitters	PLOQ715B

ENERGY TRANSFER

Standard Operating Procedures

Applicable to Hazardous Liquids Pipelines and Related Facilities

Automatic Control Valves

Code Reference :	Procedure No.: HLM.02	
49 CFR 195.428	***Effective Date:*** ***04/01/18***	**Page 1 of 7**

1.0 Procedure Descrption

This Standard Operating Procedure (SOP) describes the company requirements for the test, inspection, and maintenance of automatic control valves, level controls, over pressure protection set-points along with their associated controllers and positioners.

2.0 Scope

This SOP covers requirements for testing, inspecting, and maintenance of automatic control valves. Level controls, over pressure protection set points and their associated controllers and positioners.

3.0 Applicability

This SOP applies to all automatic control valves that maintain pressure, level or flow control, pump or station shut down and isolation independent of human intervention.

4.0 Frequency

Crude or Product: once per calendar year, not exceeding fifteen (15) months

HVL: twice per calendar year, not exceeding seven and a half (7 ½) months

5.0 Governance

The following table describes the responsibility, accountability, and authority for this SOP.

Function	Responsibility	Accountability	Authority
All Operations	Operations Personnel	Operations Manager	Director of Operations

Code Reference :	Procedure No.: HLM.02	
49 CFR: 195.428	*Effective Date: 04/01/18*	Page 2 of 7

6.0 Terms and Definitions

Terms associated with this SOP and their definitions follow in the table below. For general terms, refer to *SOP* HL*A.01 Glossary and Acronyms*.

Terms	Definitions
Automatic Isolation Valve (AIV)	Isolates pipeline or equipment downstream of the valve in order to protect the entity from overpressure
Automatic Throttling Valve (ATV)	Controls downstream pressure utilizing a controller and/or positioner
Automatic Valve	An automated operator equipped pipeline valve designed to maintain and control pressure (could be used for flow control, but limited to pressure)
Automatic Control Valve	An automated pipeline or station control valve that operates: • Independent of human intervention • Set-point(s) (variable and/or fixed) to protect pressures, flow volumes, deliveries/throughput, and/or liquid levels
Control Valve	A unitized device (valve body and controller combined) with built-in controller or positioner designed to automatically maintain and or control a specific variable (pressure, flow, differential). Control valves may or may not be designed for positive shut off
Controller	A device that operates automatically to regulate a controlled variable
Flow Control	Controls flow downstream of the valve
Flow Over-ride Control	The primary or secondary function or added control feature to limit the maximum flow rate allowed downstream of the

Terms	**Definitions**
	automatic control valve
Liquid Level Control	Controls liquid levels
Pressure Control	Controls pressure downstream of the valve
Pressure Isolation Control	An added control feature that closes the automatic control valve at a predetermined setpoint, and must be manually reopened
Pressure Over-ride Control	The primary or secondary function or added control feature to limit the maximum pressure allowed downstream of the automatic control valve
Pressure Under-ride Control	An added control feature to control a falling pressure set point downstream of the control valve
Run Switching Control	Controlled by differential pressure, volume flow rate or mass flow rate, allowing additional measurement run(s) to come in and out of service at delivery/measurement station
Station Switching Control	Controls falling pressure, allowing a valve to open to change an alternate line of service to supply a delivery/measurement stations

CAUTION: Observe upstream and downstream pressures when operator is actuated to verify that the MOP is not exceeded, and maintain current control parameters.

7.0 Automatic Control Valves

Operations Personnel performs the following procedures described in this section:

- Test and Inspection
- Maintenance

7.1 Test and

For any activity that could affect throughput, perform the following procedure.

Inspection

Step	Activity
1	If the Automatic Control Valve is used to protect the pressure design limit of a pipeline facility, **DETERMINE** the Set Point Pressure using *HLM.04 Pressure Protection and Relief Valve Capacity Verification.*
2	**ADVISE** Liquid Control and other appropriate parties before actuating automatic control valves.
3	**VERIFY** that automatic control valve(s) are disarmed or by-passed before testing the controls by **SWITCHING** the electronic control function to manual maintenance mode where applicable.
4	**VERIFY** the automatic control valve(s) will not accidentally open or close by **BLOCKING** the control signal to the valve actuator or manually **LOCKING** the valve in position, if required. **UTILIZE** bypass or standby control valves where available to maintain current control parameters.

NOTE: This need not be done if the automatic control valve(s) can be actuated fully without disruption of service.

CAUTION: Verify all valves are locked out and tagged out as specified in *SOP HLB.06 Hazardous Energy Control (Lockout/Tagout*).

Step	Activity
5	**TEST** and **CALIBRATE** transducers/and transmitters as. Verify readings with Liquids Control
6	**TEST** and **INSPECT** automatic control valves, level controls and shut downs according to manufacturer's instructions in conjunction with remaining steps

Step	Activity
	7-16.
7	**INSPECT** equipment for leakage, proper installation, good mechanical condition, and protection from dirt, liquid, and physical damage.
8	**INSPECT** and **CLEAN** all system components.
9	**REPAIR** or **REPLACE** worn or damaged parts per manufacturer's instructions.
10	**CHECK** instrument supply gas system, filters, and the supply lines. **REPLACE** filter elements, and **CLEAN** or **REPLACE** control components, if applicable.
11	**TEST** and **CALIBRATE** all pneumatic and electronic OPP controllers and operators for proper operation at set point(s) for all functions of the automatic control valve, locally and/or remotely, via Liquid Control.
12	**TUNE** PID controller for proper operation, if applicable.
13	**VERIFY** readings with Liquid Control
14	**RECORD** maintenance and/or repair beyond set point adjustments in the applicable Electronic Maintenance System Work Order Description Tab.
15	**CHECK** and **VERIFY** the proper operation of all alarms, both generated and received.
16	After all testing and inspection is complete, **VERIFY** that all isolation valves are in proper (open) position, the bypass is closed, if applicable, and **RETURN** automatic control valve(s) to automatic mode.
17	**ADVISE** Liquid Control and other appropriate parties that the facility is back in its normal mode of operation.

7.2 Maintenance

Perform the following steps to complete maintenance.

Code Reference :	**Procedure No.: HLM.02**	
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Step	Activity
1	**CHECK** and **REFILL** oil levels in the reservoirs of the operators and other lubrication reservoirs, as applicable, per the manufacturer's instructions.
2	Manually **OPERATE** to open and close the valve a few degrees to check the manual operation of the valve. **TAKE** prompt action to report and repair any valve found inoperable.
3	**CLEAN** the filter/strainer(s) for all gas supplies, as applicable.
4	**REFER** to manufacturers' service manuals for other scheduled maintenance items.

8.0 Documentation Requirements

Record data in electronic database or utilize the following form(s) as applicable:

- M.02.A Automatic Control Valve (DOT)
- Liquid Semi- Annual or Annual Safety Check form
- Electronic Maintenance Database

9.0 References

HLM.01 Valve Inspection and Maintenance

HLM.04 Pressure Protection and Relief Valve Capacity Calculation

HLB.06 Hazardous Energy Control (Lockout/Tagout)

Appendix A: OQ Task Requirements

The table below identifies the Operator Qualification (OQ) task requirements for this SOP.

Task Description	OQ Task

Commission and Maintain Control Switches	PLOQ715A
Commission and Maintain PID Loop Controllers	PLOQ711
Commission and Maintain Pneumatic Actuator	PLOQ351
Commission and Maintain Electric Actuator	PLOQ0361
Commission and Maintain Hydraulic Actuator	PLOQ0371