Version 6.2

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1. PURPOSE

To describe the process of performing External Corrosion Direct Assessment (ECDA) surveys on identified pipeline segments in accordance with ANSI/NACE SP0502, *Pipeline External Corrosion Direct Assessment Methodology*. This standard provides instructions, guidance, and identifies the requirements that are necessary to document and ensure the ECDA methodology is performed in compliance with the NACE Standard Practice.

2. INTRODUCTION

2.1. References

2.1.1. ANSI/NACE SP0502

Standard Practice, Pipeline External Corrosion Direct Assessment Methodology. This procedure complies with the latest version of the NACE standard practice.

2.1.2. 49 CFR 192 Subpart O

Gas Transmission Pipeline Integrity Management.

2.1.3. ASME B31.8S

Managing System Integrity of Gas Pipelines.

2.1.4. Cross Reference

A cross reference table is provided at the end of this procedure to reference between sections of this document and the subsections of ANSI/NACE SP0502 and 49 CFR 192.

2.1.5. Protocol Reference

A cross reference table is provided at the end of this procedure to reference between sections of this document and PHMSA protocol items. Sections of this document cited within the table are not to be removed from this procedure.

2.2. Objective

ECDA is a structured four step assessment process that is intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity. ECDA seeks to proactively prevent external corrosion defects from growing to a size that impacts the pressure carrying capacity of the pipeline segment.

2.3. Policy & Scope

2.3.1. Policy

This document shall be controlled and reviewed per the guidelines established under the Quality Assurance Plan and Management of Change Process established under the Pipeline Integrity Program.

2.3.2. Scope

This procedure shall be used to evaluate the integrity of pipeline segments that are threatened primarily by external corrosion. During direct examination of the pipeline segment other types of anomalies may be identified. In those cases the anomalies must be documented and other appropriate methodologies shall be used to evaluate the integrity of the pipeline segment(s).

2.4. ECDA Methodology

The ECDA methodology is a four-step process requiring integration of Pre-Assessment data, data from multiple indirect field inspections, data from direct examinations, and post assessment activities. The four steps of the process are:

2.4.1. Pre-Assessment

The Pre-Assessment step utilizes historic and recent data to determine whether the ECDA is feasible, identify appropriate indirect inspection tools, and define ECDA regions. Data gathering sources are identified in **Gas Standard 167.0200**.

2.4.2. Indirect Inspection

The Indirect Inspection step utilizes above ground inspection(s) to identify and define the severity of coating faults, diminished cathodic protection, and areas where external corrosion may have occurred or may be occurring. A minimum of two indirect inspection tools shall be used over the entire pipeline segment to provide improved detection reliability across the wide variety of conditions encountered along a pipeline right-of-way. Indications from indirect inspections are categorized according to severity.

2.4.3. Direct Examination

The Direct Examination step includes analyses of Pre-Assessment data and indirect inspection data to prioritize indications based on the likelihood and severity of external corrosion. This step includes excavation of prioritized sites for pipe surface evaluations resulting in validation or reprioritization of the indications.

2.4.4. Post Assessment

The Post Assessment step utilizes data collected from the previous three steps to assess the effectiveness of the ECDA process, determine reassessment intervals, and provide feedback for continuous improvement.

2.5. Roles & Responsibilities

2.5.1. Pipeline Integrity Engineering Assessment Manager

The Assessment Manager (AM) has the overall responsibility to ensure this procedure is implemented in accordance with Federal Codes and Industry recommended practices. The AM has approval and/or rejection authority for all documents, plans and exceptions associated with this procedure. The AM may delegate some or all of these approving responsibilities to other team members.

2.5.2. Pipeline Integrity Engineering Project Manager

The Engineering Project Manager (EPM) is responsible for ensuring that all aspects of the assigned ECDA projects are conducted in full compliance with this procedure. In addition, the EPM is responsible for effectively planning, documenting and communicating the various aspects and stages of the assigned ECDA projects. This procedure has response time requirements and the EPM has point responsibility to ensure that those time requirements are met throughout the project.

2.5.3. Pipeline Integrity Transmission Project Manager

The Transmission Project Manager (TPM) is responsible for effectively planning and coordinating all aspects of the bell hole inspection process in compliance with this procedure.

2.5.4. Integrity Engineer

The Integrity Engineer (IE) is responsible for the technical evaluations and analyses conducted throughout the assessment process. These include, but are not limited to sufficient data analysis, ECDA region designation, review of Indirect Inspection results, and performing remaining strength evaluations. This procedure has response time requirements for some technical evaluations and the IE is responsible for ensure those evaluations are completed within the required timeframe.

2.5.5. Technical Advisor

The Technical Advisor (TA) is responsible for developing the Aboveground Survey Plan (ASP) during the Pre-Assessment step and ensuring indirect inspections are performed in accordance with all applicable procedures referenced in this standard.

2.5.6. Inspection Personnel

The Inspection Personnel (IP) is responsible for conducting the indirect inspections and assigned direct examinations. The IP are responsible for conducting the inspections and tests in accordance with this procedure and other testing procedures that are referenced during the direct examination process.

2.6. Qualifications

The provisions of this procedure shall be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on buried ferrous piping systems.

2.6.1. Minimum Qualifications

Table 2.1 identifies the minimum qualifications required among approvers for each step of the ECDA process in accordance with **Manual TIMP.15**.

Table 2.1: TIMP Qualifications Requirements

Requirements	AM	EPM	IE	TA	TPM	IP
ECDA Procedure Training	X	X	X	X	X	
NACE CP1 or a minimum of 5 years of CP experience	X	X	X	X		
Bell Hole Inspection Requirements Training	X	X	X		X	X
Pipeline Remaining Strength Training (eg. KAPA)	X		X			
Operator Qualification Requirements				X		X
ASNT Level 1 UT & MPI						X
GPS Training (Annual)						X

AM = Assessment Manager
EPM = Engineering Project Manager
IE = Integrity Engineer
TA = Technical Advisor
TPM = Transmission Project Manager
IP = Inspection Personnel

2.7. Definitions

Additional definitions are located in **Manual TIMP.A**. The following are definitions of some key terms used in this procedure:

Alternating Current Voltage Gradient (ACVG): A method of measuring the change in leakage current in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.

Anomaly: An unexamined pipe feature which is classified as a potential deviation from sound pipe material, welds, or coatings. All engineering materials contain anomalies which may or may not be detrimental to material performance. Indications of anomalies may be determined by nondestructive inspection methods such as in-line inspection (ILI).

Bell Hole: An excavation that minimizes surface disturbance and provides sufficient room for examination and/or repair of buried facilities.

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

Characterize: To estimate the length, depth, shape, severity, orientation and/or location of an anomaly.

Classify: To identify the likely cause of an indication (e.g. anomaly, non-relevant indication, component, imperfection, or other type of feature).

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

Close Interval Survey (CIS): An inspection techniques that includes a series of above ground pipe-to-soil potential measurements taken at predetermined increments of several feet (i.e. 10-100 feet) along the pipeline and used to provide information on the effectiveness of the cathodic protection system.

Coating: Liquid, liquefiable, or mastic composition that, after application to a surface, is converted into a solid protective, decorative, or functional adherent film. Coating also includes tape wrap.

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

Corrosion Activity: A state in which corrosion is active and ongoing at a rate that is sufficient to reduce the pressure-carrying capacity of a pipe during the pipeline design life.

Covered Segment: A segment of gas transmission pipeline located in a high consequence area (HCA).

Current Attenuation Survey: A method of measuring the overall condition of the coating on a pipeline based on the application of electromagnetic field propagation theory. Concomitant data collected may include depth, coating resistance and conductance, anomaly location, and anomaly type.

Defect: A physically examined anomaly:
1) With dimensions or characteristics that exceed acceptable limits; or

2) An analysis indicates the anomaly is approaching failure as the nominal hoop stress approaches the specified minimum yield strength of the pipe material.

Direct Examination: The direct physical inspection of the pipeline that may also include the use of nondestructive examination (NDE) techniques.

Desired: "Desired" data (listed in Table 3.1 in the "Need" column) should be obtained if reasonably possible or easily measured. Its omission does not require approval or documentation and does not preclude ECDA from being used as a viable assessment method.

Determination of a Condition: Occurs when adequate information is available to conclusively decide if a condition affects the integrity of the pipeline.

Direct Current Voltage Gradient (DCVG): A method of measuring the change in electrical voltage gradient in the soil along and around a pipeline to locate coating holidays and characterize corrosion activity.

Discovery of a Condition: Discovery occurs when there is adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. For ECDA, this occurs immediately upon completion of the direct examination. Defects requiring remediation must be discovered within 180 days of indirect inspection (see PHMSA FAQ #232).

Electrolytic Contact: Ionic contact between two metallic structures via an electrolyte.

ECDA region: An ECDA region is a portion of a pipeline that has similar physical characteristics, corrosion histories, expected future corrosion conditions, and that uses the same first two indirect inspection tools. ECDA regions can be discontinuous but must be contained within the same pipeline segment (see below). It is important for the analysis to take into account all of these criteria when establishing ECDA regions.

Global Positioning System (GPS): A system used to identify the latitude and longitude of locations using GPS satellites.

High Consequence Area (HCA): High Consequence Areas are locations along the pipeline that meet the characteristics specified by 49 CFR 192.

Holiday: A discontinuity [hole] in a protective coating that exposes unprotected the surface to the environment.

Imperfection: A physically examined anomaly:

1) With dimensions or characteristics that do not exceed acceptable limits, or

2) That will not result in pipe failure at pressures below those that produce nominal hoop stresses equal to the specified minimum yield stress of the pipe material.

Indication: An indirect inspection signal that has been interpreted as a feature, anomaly, or some other condition.

Instant "Off" Potential: The polarized half-cell potential of an electrode taken immediately after the cathodic protection current is interrupted, which closely approximates the potential without IR drop (i.e., the polarized potential) when the current was on.

Prioritization: The process of estimating the need to perform a direct examination at each indirect inspection indication based on current corrosion activity plus the extent and severity of prior corrosion. The three levels of priority are immediate, scheduled and monitored, in this order.

Magnetic Particle Inspection (MPI): An NDE technique used for inspecting the surface condition in steel using fine magnetic particles and magnetic fields.

Metallic Short: Direct or indirect metallic contact between two metallic structures.

Nondestructive Examination (NDE): An inspection technique that does not damage the item being examined. This technique includes visual, radiography, ultrasonic, electromagnetic and dye penetrant methods.

Pipe-to-Soil (P/S) Potential: Electric potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte. May also be referred to as pipe-to-electrolyte (P/E) potential or structure-to-electrolyte potential.

Project: ECDA activities that occur in the same relative time frame, and where the data is integrated in the ECDA process. Projects can contain multiple ECDA regions and segments.

Remediation: Is an operation or procedure that transforms an unacceptable condition to an acceptable condition by eliminating the causal factors of a defect. Remediation may include repairs, pressure reductions, or other actions intended to preclude a defect from failing.

Repair: The act of restoring a pipeline to sound condition after damage.

Required: "Required" data listed in Table 3.1 are data elements that are required to be taken into account in IIT selection, ECDA region establishment or during the post assessment step. When accounting for these data elements, The EPM and/or IE shall integrate all required data elements in making determinations regarding the application of ECDA and assessment of results.

Segments: A portion of a pipeline that is (to be) assessed using ECDA. A segment consists of one or more ECDA regions.

Shall: Shall is a requirement that must be complied with, or its exception approved and documented in accordance with §7 of this procedure.

Should: Should is a recommendation that is desirable to follow when possible. Not following the recommendation does not require documentation or approval. (NOTE: Many of the "should" statements listed in ANSI/NACE SP0502 are required by the Integrity Management Rule, and those statements are accounted for in this procedure).

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

Superficial Corrosion: Insignificant corrosion on the surface of the pipeline (less than or equal to 10% of nominal wall thickness) that has no direct impact on the remaining strength of the pipeline, and additionally no indirect material effect on pipeline integrity or secondary interactive impact to other threats.

Third Party Damage: Damage to a gas pipeline facility by an outside party other than those performing work for the operator. For the purposes of this document it also includes damage caused by the operator's personnel or the operator's contractors.

2.8. Special Requirements

In each step of this procedure additional requirements are specified when conducting ECDA over a pipe segment for the first time. These requirements result in more extensive data collection, analysis, or other activities.

3. PRE-ASSESSMENT

3.1. Objectives

3.1.1. Collect pipeline data to determine the feasibility of conducting an ECDA;

3.1.2. Establish preliminary ECDA regions;

3.1.3. Determine Urgency Level for designated ECDA regions;

3.1.4. Select Indirect Inspection Tools (IIT); and

3.1.5. Document Pre-Assessment results.

3.2. Pipeline Segments Requiring ECDA

3.2.1. Identification of ECDA Projects

Pipeline segments requiring an ECDA can be identified from multiple sources. The Baseline Assessment Plan (BAP) within the Company's Integrity Management Program identifies pipelines that are to be assessed by ECDA. This procedure does not address the identification or relative risk ranking of pipeline segments requiring ECDA.

3.2.2. Information Provided with ECDA Project Initiation

The basic project listing from the BAP should contain the following information:

3.2.2.1. High Consequence Area Number;

3.2.2.2. Start and end stationing of the HCA;

3.2.2.3. Pipeline Number;

3.2.2.4. Scheduled Assessment Year & Risk Rank; and

3.2.2.5. List of Identified Threats.

3.3. Data Collection

3.3.1. Objectives

Data collection and analysis is a continuous activity throughout the ECDA process. Key aspects of the Pre-Assessment step include collection of pipeline data, and the consistent use and interpretation of results. The data is collected to achieve the following objectives:

3.3.1.1. Determine the feasibility of conducting an ECDA;

3.3.1.2. Selection of Indirect Inspection Tools (IIT); and

3.3.1.3. Establishment of ECDA regions.

The EPM shall consider these objectives to assure that appropriate and sufficient data is collected. Table 3.1 identifies the data elements necessary to conduct the ECDA.

3.3.2. Data Requirements

The "Need" for the data elements is identified in Table 3.1 as either "REQUIRED," "DESIRED," or "CONSIDERED." Every effort should be made to obtain all available data elements identified as "REQUIRED.". Reasonable effort should be made to obtain "DESIRED" and "CONSIDERED" data elements when they are readily available.

3.3.3. First Assessment Requirement

When conducting ECDA for the first time over a given pipeline segment, all available CP records shall be collected for the entire Data Element *Category 4. Corrosion Control* and reviewed by the EPM to develop a complete understanding of the pipeline corrosion history. This requirement is specified in both Table 3.1 and FORM A – DATA ELEMENTS SHEET.

Table 3.1: Pre-Assessment Data Elements

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
1. Pipe Related						
1.1	Material & Grade	R	ECDA is not appropriate for nonferrous materials.	Special consideration should be given to locations where dissimilar metals are joined.	The SMYS will be used for predicted burst pressure calculations that will influence the remaining life calculations.	Typically used in direct examination and post assessment. Consider for inspection tool and region selection when non-ferrous, stainless or cast iron materials are used.
1.2	Diameter	R	May reduce detection capability of indirect inspection tools.		Influences CP current flow and interpretation. The diameter will be used for predicted burst pressure calculations that will influence the remaining life calculations.	Investigate the effect of diameter on the detection capability.
1.3	Wall Thickness	R			Affects critical defect size and remaining life predictions.	
1.4	Year Manufactured	D			Older pipe materials typically have lower toughness levels, which reduces critical defect size and remaining life predictions.	If unknown, assume the same as year installed (Data Element 2.1).

[1] R = Required, D = Desired, C = Considered

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
1.5	Seam Type	R		Locations with pre-1970 low frequency ERW or flash welded pipe with increased selective seam corrosion susceptibility may require a separate region.	Older pipe typically has lower weld seam toughness that reduces critical defect size. Pre-1970 ERW or flash welded pipe may be subject to higher corrosion rates than the base metal.	Verification of "unknown" seams during Direct Examination is acceptable. Seam concerns may constitute an additional integrity threat.
1.6	Bare Pipe	R	Limits ECDA application. Fewer available tools.	Segments with bare pipe in coated pipelines should be in separate ECDA regions.	Specific ECDA methods are required.	
2. CONSTRUCTION RELATED						
2.1	Year Installed	R		Older pipe may have greater corrosion damage.	Affects time over which coating degradation may have occurred, defect population estimates, and corrosion rate estimates.	
2.2	Route Changes/ Modifications	R		Changes may require separate ECDA regions.		
2.3	Backfill /Construction Practices	D	Backfill with large amount of rock may affect the feasibility of the ECDA process.	Construction practice differences may require separate ECDA regions.	May indicate locations at which construction problems may have occurred (e.g., backfill practices influence probability of coating damage during construction).	

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
2.4	Location of major pipe appurtenances such as valves and taps	D		Significant drains or changes in CP current should be considered separately; special consideration should be given to locations where dissimilar metals are connected.	May impact local current flow and interpretation of results. Dissimilar metals may create local corrosion cells at points of contact. Coating degradation rates may be different from adjacent regions.	
2.5	Casing materials and design	R		Cased pipe with problematic casing materials and designs that are known to cause or promote external corrosion require separate regions.		
2.6	Past knowledge of metallic or electrolytic contact	R		Casings that are found to have been metallically or electrolytically shorted in the past (even seasonally) shall be placed in a separate region.		
2.7	Casing Construction Techniques	D	May preclude the use of some indirect inspection tools.	Different construction techniques that result from changes in construction crews/ contractors and installation procedures require separate regions.		

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
2.8	Location of bends, including miter bends and wrinkle bends	D		Presence of miter and wrinkle bends may influence region selection.	Coating degradation rates may be different from adjacent regions. Corrosion on miter and wrinkle bends can be localized, which affects local current flow and interpretation of results.	
2.9	Depth of Cover	D	Restricts the use of some indirect inspection techniques.	May require different ECDA regions.	May impact current flow and interpretation of results.	
2.10	Underwater sections and river crossings	R	Significantly restricts the use of many indirect inspection techniques.	Requires a separate ECDA region if the water crossing is ≥2x the PCM interval, or approx. ~100 feet.	Changes current flow and interpretation of results.	Tool spacing interval should be considered in the approach used to define water crossings.
2.11	Locations of river weights or anchors	D	Restricts the use of some indirect inspection techniques.	May require separate ECDA regions.	Influences current flow and interpretation of results. Corrosion near weights and anchors can be localized which affects local current flow and interpretation of results.	
2.12	Proximity to other pipelines, structures, electric transmission lines, and rail crossings	R	May preclude use of some indirect inspection methods.	Regions where the CP currents are significantly affected by external sources should be treated as separate ECDA regions.	Influences local current flow and interpretation of results.	

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
3. Soils/Environment						
3.1	Soil Characteristics/ Types (including soil contamination)	D	Some soil characteristics reduce the accuracy of various indirect inspection techniques.	Influences where corrosion is most likely. Significant differences generally require separate ECDA regions.	Can be useful in interpreting results. Influences corrosion rate and remaining life assessment.	Soil data may be collected at later stages of the process after review of the ECDA regions for appropriateness.
3.2	Drainage	D		Influences where corrosion is most likely. Significant differences may require separate ECDA regions.	Can be useful in interpreting results. Influences corrosion rate and remaining life assessment.	
3.3	Topography	D	Conditions such as rocky areas can make indirect inspections difficult.			
3.4	Carrier pipe exposure to humid/dry air	D		If the casing resides in an area that the operator has identified as an atmospheric corrosion monitoring area, the casing should be placed in a separate region.		
3.5	Land Use (current/past)	R	Paved roads, etc., influence indirect inspection tool selection.	Can influence ECDA application and region selection.		Asphalt, concrete, agricultural, residential, industrial, etc.
3.6	Frozen Ground	C	May affect the applicability and effectiveness of some ECDA methods.	Frozen areas should be considered separate regions.	Influences current flow and interpretation of results.	

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
4. Corrosion Control (First Assessment Requirement)						
4.1	CP System Type (anodes, rectifiers and locations)	R	May affect ECDA tool selection.		Localized use of sacrificial anodes within impressed current systems may influence indirect inspection. Influences current flow and interpretation of results.	
4.2	Known stray current sources/ locations	D		Areas of known stray current may require a separate region.	Influences current flow and interpretation of results.	
4.3	ETS Locations (Pipe access points)	R		May provide input when defining ECDA regions		
4.4	CP Evaluation Criteria	R			Used in post assessment analysis.	MAXIMO, DFIS, CPDM.
4.5	CP Maintenance History: *(Assessment Year)*	R			Parameter used to calculate pipeline life.	Year pipeline will be assessed using ECDA.
4.6	CP Maintenance History: *(Year CP installed)*	R			Used to determine years without CP, years of questionable CP history and years of adequate CP history.	Documented year cathodic protection was installed on the pipeline.
4.7	CP Maintenance History: *(Year of first CP record)*	R				Year of first documented CP read. Data can be obtained from MAXIMO, DFIS and/or CPDM.
4.8	CP Maintenance History: *(Year of CP criteria change)*	R				Year CP criteria was changed (i.e. -850 mV to 100 mV Shift).

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
4.9	CP Maintenance History: *(Years below criteria)*	R				Number of years the pipeline has been below the CP evaluation criteria threshold.
4.10	Years Without CP Applied	R			Calculated from Data Elements 4.5 through 4.9. Used to determine Urgency Criteria for each designated ECDA region.	Aligns with §A1.2 (d), (e) and (f) from ASME/B31.8G-2004.
4.11	Years of Questionable CP	R				
4.12	Years of Adequate CP	R				
4.13	Pipe Coating Type	R	ECDA may not be appropriate for coatings that cause shielding (coatings with high dielectric constants).	Different coating types may warrant different ECDA regions.	Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.	Can CIS, DCVG detect changes between tape and non-shielding coatings?
4.14	Joint Coating Type	R	ECDA may not be appropriate for coatings that cause shielding.	Different coating types may warrant different ECDA regions.	Shielding caused by certain joint coatings may lead to requirements for other assessment activities.	Field investigation of joint coating type during Direct Examination is acceptable.
4.15	Coating Condition	R	ECDA may be difficult to apply with severely degraded coatings.	Different coating conditions may warrant different ECDA regions.		Engineering, PCMR.
4.16	Current Demand	R		Different current demands may warrant different ECDA regions.	Increasing current demand may indicate areas where coating degradation is leading to more exposed pipe surface area.	
4.17	CP Survey Data/History	R		Different corrosion history may warrant different ECDA regions.	Can be useful in interpreting the results.	Engineering.

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
5. OPERATIONAL DATA						
5.1	Pipe Operating Temperature	D	May cause coating to disband from substrate.	Significant differences generally require separate ECDA regions.	Can locally influence coating degradation rates and susceptibility to SCC.	Consider when within 20 miles downstream of compressor station discharge.
5.2	MAOP	R				GPA
5.3	Operating Stress Level	R			Impacts critical flaw size and remaining life predictions.	MAOP should be used to determine stress levels.
5.4	Monitoring Programs (Coupon, leak patrol history, etc.)	D		May provide input when defining ECDA regions.	May impact repair, remediation and replacement schedules.	MAXIMO.
5.5	Pipe Inspection Reports (excavation)	D		May provide input when defining ECDA regions.	May provide insight into corrosion rate.	PCMR, Engineering.
5.6	Repair History (Such as steel or composite repair sleeves, repair locations, etc.)	R	May affect ECDA tool selection.	Prior repair methods, such as anode additions may influence region selection.	Provide useful data for post assessment analysis.	PCMR, Engineering.
5.7	Leak/Rupture History (external corrosion)	R		Can indicate condition of existing pipe.	May assist in determining corrosion rate.	Engineering.
5.8	Evidence of MIC	D			MIC may accelerate external corrosion.	Engineering.
5.9	Type/frequency of third party damage	R		Damage may warrant different ECDA regions.	High third-party damage areas may have increased indirect inspection coating fault defects.	CPUC Reports, one call records, PCMRs.
5.10	Data from previous over-the-ground or from-the-surface surveys	R		Different corrosion history may warrant different ECDA regions.	Essential for Pre-Assessment and region selection.	Engineering.

No.	Data Element	Need[1]	Indirect Inspection Tool (IIT) Selection	ECDA Region Selection	Use & Interpretation of Results	Comments
5.11	Hydrostatic Testing Dates/Pressures	D			Influences inspection intervals.	
5.12	Other prior integrity-related activities – CIS, ILI runs, etc.	R	May affect ECDA tool selection.	Different corrosion history may warrant different ECDA regions.	Useful post assessment data.	Engineering.

3.3.4. Global Pre-Assessment

Global Pre-Assessment (GPA) is the process of collecting data from pipeline records in accordance with **Gas Standard 167.0200** and qualifies for acceptance as the ECDA Pre-Assessment data collection requirement.

The information gathered during this process is recorded on a global pre-assessment template (GPAT) spreadsheet, reviewed for quality control (QC) and submitted for uploading into the HPPD. Once the information has been uploaded into the HPPD, the EPM shall obtain HCA maps for the project.

3.3.5. Data Sources

Gas Standard 167.0200 provides guidance regarding possible sources for each data element in Table 3.1. If the data element is not available in the listed sources, the EPM is responsible for applying good judgment in seeking the data elsewhere.

3.3.6. Field Data Collection

Examining the physical locations where the ECDA is to be conducted is a key activity in the gathering of data. It is important to collect available data to achieve the objectives of the Pre-Assessment and effectively plan for the Indirect Inspection step of the ECDA process. Hence, preparation is essential to conducting an effective field visit. Data typically collected during field visits is shown in Table 3.2.

Table 3.2: Typical Field Collection Data

Data Element	Description
2.2	Route changes in the pipeline that is not reflected in company documents.
2.9	Dramatic changes in the depth of cover.
2.10	Details on under water crossings.
2.12	Proximity to other pipelines, HV transmission lines and rail crossings.
3.1	Soil characteristics and types.
3.2	Drainage along the pipeline and areas where the pipeline crosses seasonal creeks.
3.3	Topography where it is extremely rocky or steep or where access is difficult.
3.5	Past and present land use, type of paving, accessibility due to private lands, development, crossings or busy roads or highways.
3.6	Possibility of frozen ground.
4.1	CP systems, location of rectifiers, ETS stations.
4.2	Sources of stray current and their proximity to the pipeline.
4.3	Test point locations and access to the pipe.

3.3.7. Identification of Missing Data

Once Global Pre-Assessment data is collected, the EPM shall analyze the data to identify missing elements, and develop a list of data that will need to be obtained in the field. FORM A may be used for this purpose.

3.3.8. Documentation

All data collected in the field that will be used in the ECDA shall be documented on FORM A.

3.3.9. Project Document File

Each ECDA project shall be maintained using a suitable filing system to house the project documentation - including both hardcopy and electronic media. The system shall be organized to allow the effective storage of correspondence, pipeline data, inspection and analysis results, disposition of findings, and re-inspection intervals.

3.4. Sufficient Data Analysis

3.4.1. Objective

Sufficient data analysis is the process of affirming that the application of ECDA is generally appropriate and can effectively proceed after data collection is completed. Consideration of missing "required" data elements is managed through the review and documentation of conservative assumptions, or the collection of supporting data during subsequent stages in the ECDA process.

3.4.2. Data Element Review

The EPM shall document these assumptions or responses using FORM B – FEASIBILITY ANALYSIS.

3.5. Feasibility Analysis

3.5.1. Objective

Feasibility analysis is the process of identifying conditions that would preclude the application of ECDA, evaluating their impact/effect on indirect inspection tools, and determining whether ECDA remains a viable option.

The specific feasibility items that are considered essential data that directly affect the ability to perform indirect inspection are highlighted in Table 3.1. If any of these data items are identified as part of an ECDA project, the data must be evaluated for the following potential impact to the inspection:

3.5.1.1. Locations at which coatings cause electrical shielding;

3.5.1.2. Backfill with significant rock content or rock ledges;

3.5.1.3. Certain ground surfaces such as pavements, frozen ground, and reinforced concrete;

3.5.1.4. Situations that lead to an inability to acquire aboveground measurements in a reasonable time frame (typically 60 days between surveys unless determined otherwise);

3.5.1.5. Locations with adjacent buried metallic structures;

3.5.1.6. Inaccessible areas (e.g. casings, excessive pipe depths); and

3.5.1.7. Bare pipe.

3.5.2. Specific Feasibility Review

The EPM shall review the data elements in Table 3.1 and determine if there are locations along a pipeline segment at which indirect inspections are not practical or cannot be applied. The review must include the specific data elements noted in §3.5.1 as a minimum for ECDA feasibility.

The EPM and IE shall document and approve the result of the review on FORM B. If the determination is that any one of these specific conditions will preclude the use of indirect inspection tools, application of ECDA will be considered infeasible. Selection of an alternate integrity assessment method (e.g. ILI, PT or other technology) shall be initiated using Company Form 2111.

3.5.3. Documentation

The EPM shall document the result of the feasibility analysis on FORM B. FORM B shall be reviewed and signed by the EPM and IE.

If the analysis results in the determination that ECDA is not feasible, a report to file shall be generated by the EPM to document the causal factors. The following topics shall be addressed in the report:

3.5.3.1. Adverse conditions that may make the ECDA infeasible;

3.5.3.2. A conclusion regarding the feasibility of conducting ECDA for the pipeline segments in the project; and

3.5.3.3. Attachment of any required Integrity Management Plan forms to communicate the change in assessment method in accordance with Manual TIMP.14.

3.5.3.4. No further action is required for ECDA projects deemed to be infeasible.

3.6. Designation of ECDA Segments

3.6.1. Criteria

An ECDA segment is a pipeline segment that is electrically continuous and will be surveyed within the same timeframe. An ECDA segment may consist of one or more ECDA regions.

For geographically distributed segments, pipeline segments may not need to be electrically continuous or surveyed within the same timeframe.

3.6.2. Documentation

The EPM shall document the ECDA segment designations on FORM C: ECDA REGION REPORT or equivalent.

3.7. Designation of ECDA Regions

3.7.1. Criteria

ECDA regions are subsets of ECDA segments, and are defined by a four-point criteria which considers:

3.7.1.1. Similar design/physical characteristics, (such as, but not limited to, the Pipe Related data elements listed in Table 3.1);

3.7.1.2. Similar operating/corrosion histories;

3.7.1.3. Similar expected future corrosion condition; and

3.7.1.4. Use of the same primary IITs.

ECDA regions may be non-contiguous (i.e. a region may be separated by other regions, or distributed in physically separated sections along an ECDA segment).

Additional supplemental inspection tools may be specified, but do not necessarily require the designation of additional regions on the basis of criterion 3.7.1.4.

3.7.2. Description

The EPM & IE shall analyze the integrated data collected during the Pre-Assessment step and assign each pipeline segment to an ECDA region using the four step criteria in §3.7.1.

Region designations are based upon judgment and documented rationale – therefore it is important that all data categories are considered when establishing ECDA regions.

Region definitions established during Pre-Assessment are considered preliminary, and can be fine-tuned as necessary based on the results of both the indirect inspection and direct examination. Regions may be separated or aggregated during the Direct Examination step based on the four-point criteria listed in §3.7.1 due to:

3.7.2.1. Discovery of changes or similarities in pipeline characteristics;

3.7.2.2. Changes/modifications to primary tools used during indirect inspection; or

3.7.2.3. Field conditions encountered during indirect inspection.

Changes to region designations shall be documented on FORM C to demonstrate consistency with region definitions throughout the process (see §5.6).

3.7.3. Documentation

The EPM shall document the "start" and "end" boundaries of each ECDA region and significant characteristics (data elements) which distinguish a new ECDA region on FORM C.

3.8. Urgency Criteria

3.8.1. Objective

Establish the urgency level for each designated ECDA region for use during final prioritization of indications.

3.8.2. Description

The urgency level for each ECDA region is determined by using Pre-Assessment data elements to evaluate three categories of corrosion history:

3.8.2.1. Corrosion Leak History,

3.8.2.2. Cathodic Protection History, and

3.8.2.3. Other Corrosive Indicators.

The evaluation criteria for the categories are described below.

3.8.3. Corrosion Leak History

Use data elements 5.5 through 5.7 to determine the urgency level for this category.

Level	Rank	Description
A	Recent	Any corrosion leaks or ruptures over the past 7 years, on the covered segment.
B	Previous	Any corrosion leaks or ruptures over the life of the pipeline on the covered segment.
C	None	No history of corrosion leaks or ruptures on the covered segment.

For cased pipe segments, only the corrosion leak history category is used to determine the urgency level.

3.8.4. CP History

Use data elements 4.6 through 4.9 to determine the urgency level for this category.

Level	Rank	Description
A	Inadequate	15% or less of the pipe lifespan has met or exceeded cathodic protection criteria.
B	Questionable	Between 15% and 85% of the pipe lifespan has met or exceeded cathodic protection criteria.
C	Adequate	85% or more of the pipe lifespan has met or exceeded cathodic protection criteria.

3.8.5. Other Corrosive Indicators

Use data elements 3.1, 3.2, 4.2, 4.15, 5.5 – 5.7 and 5.10 to determine the urgency level for this category. The corrosive indicators are:

3.8.5.1. High soil corrosivity rates based on soil resistivities lower than 1,000 ohm-cm;

3.8.5.2. Area of stray current interference;

3.8.5.3. Bare pipe;

3.8.5.4. Shielded or disbonded coating conditions;

3.8.5.5. Presence of corrosive bacteria;

3.8.5.6. History of wall loss in excess of 20% of the nominal wall thickness; and

3.8.5.7. Other factors discovered through Pre-Assessment deemed critical by the team.

Level	Rank	Description
A	High	4 or more of the indicators listed above.
B	Moderate	2 or 3 of the indicators listed above.
C	Low	0 or 1 of the indicators listed above.

3.8.6. Criteria

The urgency level for an ECDA region is the highest level (with A being the highest) for any one of the three categories shown in Table 3.3.

Table 3.3: Urgency Criteria

Level	Corrosion Leak History	CP History	Other Corrosive Indicators
A	Recent	Inadequate	High
B	Previous	Questionable	Moderate
C	None	Adequate	Low

3.8.7. Documentation

The EPM shall record the final urgency level for each ECDA region on FORM C.

3.9. Indirect Inspection Tool Selection

3.9.1. Number of Indirect Inspection Tools

The EPM shall select at least two complimentary primary indirect inspection tools (IITs) from Table 3.4 for each ECDA region in the study area. In addition to the two primary IITs, the EPM may require additional supplemental inspections, data collection, and analysis. The indirect inspections must generate adequate data to characterize the performance of the applied cathodic protection and coating condition; there is no limit on the number of IITs that may be utilized.

3.9.2. Selection Basis

The EPM shall select primary IITs based on their performance reliability under the specific pipeline conditions for each segment based on the information obtained in Table 3.1.

The EPM shall endeavor to select primary tools that are complimentary to one another (i.e. the capabilities of one tool should compensate for the limitations of the other). The EPM should consider the guidance provided in Tables 3.4 and 3.5.

Additional tools may be selected at the discretion of the EPM to supplement the assessment of specific circumstances, including but not limited to:

3.9.2.1. Crossings/casings;

3.9.2.2. Static or dynamic interference;

3.9.2.3. Third party mechanical damage;

3.9.2.4. Special environments; and

3.9.2.5. Compensation for significant unknown data elements.

Guidelines for inspection tool selection for typical situations are listed in Table 3.6 in order of primary, secondary and tertiary inspection options in order of preference. The EPM may utilize tools other than those listed in Table 3.4, and may utilize different selections than those shown in Table 3.6, but shall follow the exception process described in §7 of this procedure to document his/her justification.

3.9.3. Special Condition

The EPM may substitute a 100% direct examination that follows the requirements of §5.2 of this procedure in lieu of indirect inspections and selected direct examinations at bell hole locations. In such a case, the Pre-Assessment and Post Assessment steps within this procedure shall be completed in their entirety.

3.9.4. First Assessment Requirement

When conducting ECDA for the first time over a pipeline segment:

3.9.4.1. A third complimentary indirect inspection tool shall be used for each ECDA region in the study area; and

3.9.4.2. Direct contact with the subsurface soil shall be achieved by boring through pavement to ensure viable reads for soil dependent IITs.

3.9.5. Documentation

The EPM shall document the IIT selection for each ECDA region on FORM C. FORM C shall be reviewed and signed by the EPM and IE.

Table 3.4: ECDA Tool Selection Matrix

Condition	Close Interval Survey (CIS)	Voltage Gradient Surveys (ACVG or DCVG)	AC Attenuation Survey (ACA)	Guided Wave Ultrasonic Testing (GWUT)	Soil Characterization
Coating Holidays	Yes	Yes	Possible	No	No
Anodic Zones on Bare Pipe	Yes	No	No	Yes	Yes
Near River or Water Crossings	Yes	No	Possible	Yes	Yes
Under Frozen Ground	No	No	Yes	Yes	No
Stray Currents	Yes	Yes	Yes	Yes	No
Shielded Corrosion Activity	No	No	No	Yes	Yes
Adjacent Metallic Structures	Yes	Yes	Yes	Yes	Yes
Near Parallel Pipelines	Yes	Yes	Yes	Yes	Yes
Under HVAC Electric Transmission Lines	Yes	Yes	Possible	Yes	Yes
Under Paved Roads	Possible	Possible	Yes	Yes	Possible
Uncased Crossings	Yes	Yes	Yes	Yes	Possible
Cased Crossings	Yes	Yes	Yes	Yes	Possible
Wetlands	Yes	Yes	Yes	Yes	Yes
Rock Terrain, Ledges or Backfill	No	No	Yes	Yes	Yes

Table 3.5: Indirect Inspection Tool Guide

Indirect Inspection Tool	Measurement Attributes	Typical Uses	Less Suitable For:	Complimentary Tools
Close Interval Survey (CIS)	Measures pipe to soil potentials along the pipeline at typically 10 to 100 foot intervals.	Generally used to assess the performance of CP systems and estimate the location of coating holidays. May detect interferences, shorted casings, electrical or geological shielding, contact with other metallic structures and defective electrical isolation joints.	Pipelines that are below paved areas will require holes to be drilled to the soil. Is not effective on coating systems that have disbonded and are shielding.	ACVG, DCVG, GWUT.
Voltage Gradient Surveys (ACVG or DCVG)	Measures voltage gradients resulting from current pickup and discharge points at holidays.	Generally used to precisely locate large and small coatings holidays on buried pipelines. Capable of precisely locating holidays on the pipeline.	Pipelines that are below paved areas will require holes to be drilled to the soil. Is not effective in detecting coating systems that have disbonded and are shielding.	CIS, GWUT
AC Attenuation Surveys (ACA)	Measures the electromagnetic field attenuation emanating from the pipe induced with an AC signal.	Can be used for pipelines under pavement and CP systems that are difficult to isolate. Qualitatively ranks coating quality and highlights areas with the largest holidays.	Not indicative of pipe to soil potential or effectiveness of CP. Is ineffective under HV transmission lines. Is not effective in detecting coating systems that have disbonded and are shielding.	CIS, GWUT
Guided Wave Ultrasonic Testing (GWUT)	Locates interior and exterior wall loss. Can potentially estimate the degree and circumferential location of the wall loss.	Can be used for pipelines under pavement, in casings, road crossings, and pipelines with shielded coatings, or effectively expand the length of pipe examined at a bell hole.	Requires direct access to the pipeline and removal of the coating.	ACA, CIS
Soil Characterization	Measures the resistivity of the soil in Ohm-cm.	Can be used to approximate potential corrosivity along the pipeline, or correlate differences in current distribution.	Not indicative of pipe to soil potential or effectiveness of CP	CIS, ACVG, DCVG, ACA, GWUT

Table 3.6: Standard Tool Selection Guidelines[2]

Conditions	Close Interval Survey (CIS)	Voltage Gradient Surveys (ACVG or DCVG)	AC Attenuation Survey (ACA)	Guided Wave Ultrasonic Testing (GWUT)	Soil Characterization
Polarization	1ST	--	--	--	--
Coating Holidays	2ND	1ST	3RD	--	--
Current Distribution	1ST	--	2ND	--	--
Anodic Zones on Bare Pipe	1ST	--	--	3RD	2ND
Water Crossings	1ST	--	2ND	3RD	--
Stray Currents	1ST	--	2ND	--	--
Shielded Corrosion Activity	--	--	--	2ND	1ST
Adjacent Metallic Structures	1ST	--	2ND	--	--
Near Parallel Pipelines	1ST	2ND	--	--	--
Under HVAC Electric Transmission Lines	1ST	2ND	3RD	--	--
Casings[3]	2ND	3RD	1ST	--	--

[2] Indirect Inspection Tools are listed in order of selection priority for typical situations.
[3] Casing assessment methods may be modified to accommodate circumstances.

3.10. Aboveground Survey Plan

The Aboveground Survey Plan (ASP) is comprised of multiple studies that are performed on the target pipeline(s) to determine which complimentary IITs may be utilized during the Indirect Inspection step. This plan shall be developed and documented in accordance with **Gas Standard 167.0247**. The TA shall submit the completed ASP to the EPM and IE for review prior to the Pre-Assessment Meeting.

3.11. Pre-Assessment Meeting

3.11.1. Objective

To provide technical insight into ECDA of the defined area, communicate the plan of how the ECDA will be conducted and build consensus for the plan. The Pre-Assessment meeting is also used to improve the application of ECDA by incorporating feedback from critical personnel and reviewing relevant findings including those from previous assessment activities.

3.11.2. Agenda

The EPM shall coordinate the meeting to review the following:

3.11.2.1. Aboveground Survey Plan;

3.11.2.2. Data reports including findings from previous assessments;

3.11.2.3. Pipeline maps;

3.11.2.4. Form A: Data Elements Sheet;

3.11.2.5. Form B: Feasibility Analysis; and

3.11.2.6. Form C: ECDA Region Report.

The AM, EPM, IE, and all other personnel deemed critical to the project's success shall be in attendance.

3.11.3. Documentation

The IE shall maintain a record of all Pre-Assessment discussions and conclusions. Changes to the Pre-Assessment data, feasibility analysis, IIT selection, and ECDA regions analysis shall be documented on the appropriate forms by the EPM. The record shall be stored in the project file and approved by the AM, EPM and IE.

4. INDIRECT INSPECTION

4.1. Objectives

4.1.1. Locate and define the severity of coating faults;

4.1.2. Identify areas where external corrosion may have occurred or may be occurring; and

4.1.3. Analyze and prioritize indications for Direct Examination.

4.2. Indirect Inspection Procedure Review

Each IIT shall have a corresponding written procedure. IP are required to submit their inspection and operating procedures for review. If SoCalGas specific procedures are used, they shall also be reviewed. The IE shall be responsible for satisfying the review requirements outlined below.

4.2.1. Procedure Content

Each of the above ground procedures shall consider the following:

4.2.1.1. Numbering

The procedure shall have a unique alphanumeric number assigned to it with a revision number.

4.2.1.2. General Description

The procedure scope and general theory regarding how the IIT works; including what it measures and detection capabilities.

4.2.1.3. Limitations

Where the IIT should not be used, what it cannot detect, and its level of sensitivity.

4.2.1.4. Procedure Qualifications

How the IIT procedure was qualified and location of the records that document the qualification.

4.2.1.5. Safety Considerations

General and specific safety considerations; including adherence to SoCalGas safety standards. Listing of general hazards and what to do in case of an injury.

4.2.1.6. Instrumentation

A list of equipment by name and model number. This list should also include special measurement equipment that will be used in case of special field situations such as stray currents. Any equipment not included on this list must be approved by the IE prior to its use.

4.2.1.7. Personnel Qualifications

Qualifications of the personnel conducting the exam, including how the personnel were trained on the specific procedure.

4.2.1.8. Step-by-step Instructions

Specific, easy to follow instructions on conducting the survey. These instructions shall include:

4.2.1.8.1. Calibration: The calibration of the equipment prior to and during the survey.

4.2.1.8.2. Equipment Connection: The connection of instrumentation, the set-up interrupters, etc.

4.2.1.8.3. Pipe Location: The method of locating the pipe.

4.2.1.8.4. Measurements: The method of taking measurements and the frequency or interval the measurements should be taken, including the process for decreasing the interval spacing.

4.2.1.8.5. Special Diagnostics: The techniques and when they are used to address special field situations.

4.2.1.8.6. Distance Measurement: The method of tracking the distance traveled along the survey. The frequency of geo-references.

4.2.1.8.7. Recording Data: The recording of data and special diagnostic techniques.

4.2.2. Preparation and Approval

The procedure shall document the person who prepared it and the date it was prepared, including review and approval by a responsible person in the organization that issued it. Both of the above requirements are indicated by signatures and dates.

4.2.3. Frequency of Review and Approval

The IE shall review each procedure for adequacy. Each Company or vendor IIT procedure shall be reviewed and approved prior to use. Review is also required whenever there has been an issued revision to a specific IIT procedure.

4.2.4. Documentation and Procedure Filing

Comments for each IIT procedure shall be recorded. Each approved procedure with any amendments shall be kept in the ECDA program management file.

4.3. Marking of Inspection Areas

4.3.1. Objective

To designate the survey boundaries for all indirect inspection.

4.3.2. Process

4.3.2.1. The beginning and end points of each inspection area identified on FORM C shall be clearly marked in the field to eliminate ambiguity regarding the survey limits prior to indirect inspection surveys.

4.3.2.2. A minimum 50 ft. buffer shall be added to the ends of each inspection area to ensure full coverage during inspection where practical. A buffer is not required at the end of a pipeline (e.g. - where a tee terminates into another pipeline).

4.3.2.3. The inspection area boundaries may exceed the ECDA region boundaries so that the entire length of the ECDA region and/or HCA is inspected with no gaps. The EPM may also desire to expand the inspection area to evaluate pipe outside of the HCA.

4.3.3. Type of Markings

Both ends of each inspection area shall be identified with one or more of the following methods:

4.3.3.1. By a clearly identifiable land mark that has a unique name, such as streets and buildings.

4.3.3.2. Painted markings on the roadway or other pavement with arrows pointing towards the center of the inspection area.

4.3.3.3. Highly visible stakes, nail markers or other suitable marking device with the ECDA region number on them and an arrow pointing to the center of the region.

4.3.3.4. GPS Located Positions accompanied by a physical marking described above.

4.4. Indirect Inspection Field Meeting

The EPM shall have a field meeting with the IP to review the following:

4.4.1. Notifications Prior to Assessment

Responsibilities for "One Call" notifications regarding the location and time of the inspections.

4.4.2. Inspection Areas

Review first-hand the boundaries of each inspection area.

4.4.3. Review of Records

FORM C, maps and other pertinent documents.

4.4.4. Cathodic Protection Equipment

The location and operation of all associated cathodic protection equipment.

4.4.5. Indirect Inspection Tools

Review all IITs that will be used in the ECDA project, spacing intervals required for each IIT (specified in Table 4.1) and method to achieve contact with the soil if the area is paved. Additional tests required for special circumstances should also be addressed.

The maximum intervals specified in Table 4.1 shall be specified in the project request for proposal (RFP) or governing project specifications, including notification and approval requirements for any deviation. Tool sensitivities shall also be specified in the RFP or governing project specifications, according to tool type.

Table 4.1: Maximum Indirect Inspection Spacing Intervals

IIT	Interval Spacing	Comments
CIS	10 ft.	CIS is to be performed in bar holes in asphalt pavement.
ACVG or DCVG	10 ft.	ACVG or DCVG is to be performed in CIS bar holes in asphalt pavement.
ACA Survey	50 ft.	Deviations shall be noted and recorded.
GWUT	N/A	Spacing defined on as-needed basis.
Soil Resistivity	~ 1,000 ft.	No fewer than 2 measurements per HCA (Beginning, End).

4.4.6. Access to ECDA Regions

How access to the inspection areas will be managed. Contacts, schedule, etc.

4.4.7. Schedule

Dates and times the IP will conduct the survey.

4.4.8. Landowner Contact

Protocol if landowners question field personnel.

4.4.9. Safety & Environmental Hazards

Discuss safety hazards such as traffic, overhead lines, rectifier potentials, flora and fauna.

4.4.10. Notification of Abnormal Conditions

IP shall notify the EPM when abnormal conditions or situations develop. Discuss what these conditions are; e.g. - extreme data, unusual landowner contact, pipeline safety concerns, inspection tool does not appear appropriate, personnel injury and changes in inspection dates, etc.

4.4.11. Documentation

Any changes to the Indirect Inspection Plan shall be documented on one or more of the following forms as appropriate:

4.4.11.1. Form B: Feasibility Analysis

4.4.11.2. Form C: ECDA Region Report

4.5. Indirect Inspections

4.5.1. Breadth of Inspections

Each of the primary indirect inspections shall be conducted over the entire ECDA region. Minimum requirements for some IITs are provided in the following procedures:

4.5.1.1. **Gas Standard 167.0248,** Alternating Current Attenuation Survey;

4.5.1.2. **Gas Standard 167.0249,** Close Interval Survey;

4.5.1.3. **Gas Standard 167.0250,** Voltage Gradient Survey; and

4.5.1.4. **Gas Standard 167.0251,** Soil Resistivity Survey

4.5.2. Supplemental Inspections

Indirect inspections, other than the primary methods, may be conducted as determined by the EPM and documented on FORM C.

4.5.3. Station Numbering

Each indirect inspection area shall be designated with a definitive beginning and end location (e.g. measurements from landmarks, pipeline stationing, GPS coordinates).

Inspection "begin" locations shall be designated with a survey stationing of 0+00 unless otherwise instructed by the EPM.

4.5.4. Additional Data Collection

The elements in Table 4.2 shall be collected for indirect inspections in conjunction with the IIT readings.

Table 4.2: Additional Data Collection Elements[4]

Line Number	Type of CP Infrastructure*
Pipeline Angle Point*	Land Use
Type of Pipeline Markers*	Valves*
Topographical Features*	Roadway Name*
Farm Taps*	Foreign Line Crossings*
Survey Flag Numbers	Test Stations*
Depth of Pipe Every 100 feet (optional)*	

4.5.5. IIT Procedure Deviation

The indirect inspections shall be performed strictly in accordance with the approved procedures. Any deviation from the procedure shall be approved and documented in accordance with the Exception Process described in §7.

4.5.6. Time Between Primary Inspections

The IP shall endeavor to have the two primary indirect inspections conducted as close in time as reasonably possible, but no longer than 60 days apart. If the 60 day timeframe is exceeded, the time between inspections shall be documented through the Exception Process in §7 of this procedure. If the time exceedance is unacceptable, the primary indirect inspection must be re-conducted to comply with the 60 day timeframe.

[4] GPS readings should be taken for data elements notated with an asterisk (*).

4.6. Indirect Inspection Reporting

4.6.1. Reporting Time Requirement

The test data should be submitted to the EPM no later than 30 days after the completion of the last indirect inspection. It is the responsibility of the EPM to manage the IP to assure this requirement is met.

4.6.2. Report Content

4.6.2.1. Location and Dates

Description of the location where the inspections were performed as well as the dates they were conducted.

4.6.2.2. Weather Conditions

Description of the local weather conditions at the time of inspection; including temperature and precipitation.

4.6.2.3. IIT Types

Description of the indirect inspections performed as well as other tests such as soil resistivity and depth survey. The testing procedures shall be listed as well as the personnel conducting the test.

4.6.2.4. Current Sources

A table listing the current sources that were interrupted including output and ratings of the rectifiers, and/or bond current values, along with corresponding mileposts and survey stations.

4.6.2.5. Survey Plots

All IIT results should be plotted with station distances at 100-foot intervals. Landmarks shall be noted on the chart as well as other test data such as depth surveys, CP test stations, rectifiers, anodes, mainline valves, markers, and angle points. The period when the tests were conducted shall also be included on the plots.

4.6.2.6. GPS Coordinates

GPS coordinates shall be provided every 50 feet along the survey, for select additional data collection elements (see Table 4.2) and at each coating holiday indication.

4.6.2.7. Report Formats

The report shall be provided in both hardcopy and electronic formats.

4.7. Identification and Classification of Indications

4.7.1. Objective

To describe the process of identifying and classifying indications to estimate the likelihood of corrosion.

4.7.2. Criteria

The survey data shall be evaluated to identify and classify the severity of indications according to the criteria set forth in Table 4.3 for uncased pipe segments and/or Table 4.4 for cased pipe segments. The minimum criteria for indications are detailed under “Minor Indications.” The IP may perform the classification; however the IE is responsible for the final classification results.

Table 4.3: IIT Classification Criteria for Uncased Pipe Segments

IIT	Minor Indication	Moderate Indication	Severe Indication
CIS (On/Instant Off)	The "Instant Off" potential is more positive than -850 mV_{CSE}. — OR — Convergence of the "On" and "Instant Off" potentials is less than 50 mV_{CSE}. — OR — Other condition classified as minor by the IE.	Both the "On" and "Instant Off" potentials are more positive than -850 mV_{CSE}. — OR — Both of the following within a 200 foot. span: • Convergence of the "On" and "Instant Off" potentials is less than 50 mV_{CSE}, and • The "Instant Off" potential is more positive than -850 mV_{CSE}. — OR — Other condition classified as moderate by the IE.	The "Instant Off" potential is more positive than -500 mV_{CSE}. — OR — Both of the following within a 200 foot. span: • Convergence of the "On" and "Instant Off" potentials is less than 50 mV_{CSE}, and • Both the "On" & "Instant Off" potentials are more positive than -850 mV_{CSE}. — OR — Other condition classified as severe by the IE.
ACA[5]	$10\% \leq x < 30\%$ in 100 ft.	$30\% \leq x < 50\%$ in 100 ft.	$x \geq 50\%$ in 100 ft.
ACVG DCVG	Is an indication (gradient field) present on the carrier pipe (Yes or No).		

[5] *x* = attenuation change.

Table 4.4: IIT Classification Criteria for Cased Pipe Segments

IIT	Minor Indication	Moderate Indication	Severe Indication
CIS (On/Instant Off)	Pipe and casing potentials do not shift and difference in values greater than or equal to 100 mV_{CSE} when electrical contact is established. — OR — Convergence of “On” and “Instant Off” potentials at the casing ends from 10% - 20% compared to the adjacent uncased portion of the pipe when electrical contact is not established.	Shift in pipe and casing potentials when CP current is interrupted and the difference in potential values are greater than or equal to 50 mV_{CSE} but less than 100 mV_{CSE} when electrical contact is established. — OR — Convergence of “On” and “Instant Off” potentials at the casing ends from 20% - 35% compared to the adjacent uncased portion of the pipe when electrical contact is not established.	Shift in pipe and casing potentials when CP current is interrupted and the difference in potential values are less than 50 mV_{CSE} when electrical contact is established. — OR — Convergence of “On” and “Instant Off” potentials at the casing ends by more than 35% compared to the adjacent uncased portion of the pipe when electrical contact is not established.
ACA	An attenuation change less than or equal to 10% between casing ends when electrical contact is established. — OR — An attenuation change between 10% and 30% between casing ends when electrical contact is not established.	An attenuation change greater than 10% but less than 25% between casing ends when electrical contact is established. — OR — An attenuation change greater than 30% but less than 50% between casing ends when electrical contact is not established.	Attenuation change greater than or equal to 25% between casing ends when electrical contact is established. — OR — Attenuation change greater than or equal to 50% between casing ends when electrical contact is not established..
DCVG **ACVG**	Is the indication (gradient field) present on each end of the casing toward the centerline of a casing? (Yes or No)		
Panhandle or Internal Resistance	Resistance greater than or equal to 0.10 Ω	Resistance less than 0.10 Ω but greater than or equal to 0.01 Ω	Resistance less than 0.01 Ω

4.7.3. Documentation

The location of the indication along the pipeline, the primary IITs used to identify the indication and the severity of the indication according to the criteria established in Tables 4.3 and/or 4.4 shall be documented on FORM D: INDICATION CLASSIFICATION AND PRIORITIZATION or equivalent documentation.

4.8. Data Alignment and Comparison

4.8.1. The IE shall compare the results from all primary indirect inspection tools to:

4.8.1.1. Determine if alignment discrepancies exist between survey methods; and

4.8.1.2. Compare Indirect Inspection survey results to resolve inconsistencies.

4.8.2. Resolution of Data Alignment

The IE shall determine alignment discrepancies by comparing the spatial alignment of each primary IIT with Company defined stationing and incremental reference points.

4.8.3. Resolution of Data Inconsistencies

The IE shall compare primary IIT capabilities and whether their use was appropriate given the conditions of the survey (e.g. measurement spacing, pipeline appurtenances, weather, type of cover).

Once alignment has been assured, inconsistencies that cannot be resolved shall require remedial action. The IE shall pursue one or more of the following options:

4.8.3.1. Preliminary Direct Examinations

Preliminary direct examinations may be used to resolve a discrepancy in the alignment of indications. Preliminary direct examinations shall be documented on the DIRECT EXAMINATION SHEET.

4.8.3.2. Additional Indirect Inspections

Additional indirect inspections may be used to resolve discrepancies in the alignment of indications. Additional IITs used shall be documented on FORM C.

4.8.3.3. Classify Indications as Severe

Any indications where the discrepancy in alignment has not been resolved shall be classified as severe and documented on FORM D or equivalent documentation.

4.8.4. ECDA Feasibility Assessment

The IE shall reassess the feasibility of the ECDA and either confirm the process with Pre-Assessment or elect to use another integrity assessment technology (e.g. pressure testing, in-line inspection).

4.9. Prioritization of Indications

4.9.1. Objective

To estimate the need for direct examination based on integrated classification and urgency criteria results.

4.9.2. Initial Prioritization

Indications shall be initially prioritized as I, II, III, or NRI in accordance with Table 4.5 when CIS and VGS are selected as primary IITs for uncased pipe segments, Table 4.6 when ACA is selected as the primary IIT in lieu of a VGS for uncased pipe segments and/or Table 4.7 when CIS and ACA are selected as primary tools for cased pipe segments. If the potential for third party damage exists, an indication shall be initially prioritized as “TPD” in accordance with §4.9.2.4 of this procedure.

4.9.2.1. Priority I

4.9.2.1.1. Multiple severe indications that are in close proximity and potentially interacting. Example: two CIS severe indications located within the survey spacing interval of 10 have the potential to be interacting and must be accounted for in the initial prioritization.

4.9.2.1.2. Unresolved discrepancies have been noted between indirect inspection tools.

4.9.2.1.3. The likelihood of corrosion activity cannot be determined (eg. Indications due to interference with CP current).

4.9.2.1.4. Prior corrosion damage cannot be estimated.

4.9.2.2. Priority II

This priority includes indications that may have on-going corrosion activity. Indications that fall into this priority are severe indications that are not in close proximity with other severe indications and were not prioritized as Priority I.

4.9.2.3. Priority III

This priority includes indications that exhibit a low likelihood of on-going corrosion that are not Priority I or II. Indications within this category include Minor indications; which have the lowest likelihood of active corrosion.

Table 4.5: Initial Prioritization of Indications (CIS and VGS) for Uncased Pipe Segments

IIT	CIS				
	Classification	Severe	Moderate	Minor	NRI
ACVG DCVG	Yes	I	I	II	III
	No	II	III	III	NRI

Table 4.6: Initial Prioritization of Indications (CIS & ACA) for Uncased Pipe Segments

IIT	CIS				
	Classification	Severe	Moderate	Minor	NRI
ACA	Severe	I	II	II	III
	Moderate	I	II	III	III
	Minor	I	II	III	NRI
	NRI	I	III	III	NRI

Table 4.7: Initial Prioritization of Indications (CIS & ACA) for Cased Pipe Segments

IIT	CIS				
	Classification	Severe	Moderate	Minor	NRI
ACA	Severe	I	II	II	II
	Moderate	II	II	III	III
	Minor	II	II	III	NRI
	NRI	II	III	III	NRI

4.9.2.4. Priority TPD (Potential Third-Party Damage)

This priority is reserved for DCVG indications that align with an encroachment or foreign line crossing. The IE shall prioritize these indications as "TPD" on FORM D (or equivalent documentation) and the locations shall be identified on the TPD SHEET for field verification. The EPM shall coordinate the field verification of these locations with inspection personnel.

If the encroachment or foreign line crossing is not within ±2.5 feet of the DCVG indication, the indication shall be removed from the TPD SHEET. In addition, the "TPD" prioritization shall be changed to either Priority I, II, III or NRI on FORM D (or equivalent documentation) and shall be prioritized for excavation in accordance with §4.9.3 of this procedure.

If the encroachment or foreign line crossing is within ±2.5 feet of the DCVG indication, the indication shall remain on the TPD SHEET and shall be prioritized for excavation in accordance with §4.9.4 of this procedure.

4.9.3. Prioritization of Excavations

The initial prioritization results shall be integrated with the urgency criteria in §3.8 to designate indications as Immediate, Scheduled or Monitored excavation sites. This final prioritization shall be conducted in accordance with Table 4.8 for uncased pipe segments and/or Table 4.9 for cased pipe segments.

Table 4.8: Prioritization of Direct Examination Sites for Uncased Pipe Segments

Initial Priority	Urgency Level		
	Level A	Level B	Level C
I	Immediate	Scheduled	Scheduled
II	Scheduled	Scheduled	Monitored
III	Scheduled	Monitored	Monitored

Table 4.9: Prioritization of Direct Examination Sites for Cased Pipe Segments

Initial Priority	Urgency Level		
	Level A	Level B	Level C
I	Immediate	Scheduled	Scheduled
II	Scheduled	Monitored	Monitored
III	Monitored	Monitored	NRI

4.9.4. Prioritization of Third Party Damage

The IE shall prioritize the indications on the TPD SHEET based upon pipeline depth of cover measurements (field verification), nominal wall thickness data (Pre-Assessment) and age of the pipeline segment (Pre-Assessment).

4.9.5. Prioritization Time Requirements

The final prioritization of indications should be completed 30 days after receipt of the indirect inspection survey data. If prioritization exceeds 30 days, the EPM shall be notified.

4.9.6. Indirect Inspection Analysis

The IE shall compare the results of the indirect inspections with the Pre-Assessment results for each ECDA region to verify consistency in the data. If the assessment results are not consistent with operating history, the IE must reassess the feasibility of the ECDA.

The ECDA region designations may be modified based on results from the Indirect Inspection Step. The designations made at this point are preliminary and will be finalized during the ECDA Region Review in §5.6.

4.9.7. Documentation

The IE shall document the prioritization of excavation sites on FORM D or equivalent documentation. FORM D (or equivalent) shall be reviewed and signed by the EPM and IE.

4.10. Number of Excavations

The number of required excavations is determined by the number of indications, the priority of those indications, and whether the assessment is the first ECDA performed along a given covered pipeline segment. Table 4.10 provides a summary of the number of excavations required.

4.10.1. No Indications Identified

4.10.1.1. In the event that no indications are identified in a given pipeline segment, a minimum of one direct examination is required in the ECDA region identified as most likely for external corrosion in the Pre-Assessment step.

4.10.1.2. First Assessment Requirement

When ECDA is applied for the first time, one additional direct examination shall be performed in the ECDA region identified as most likely for external corrosion in the Pre-Assessment step.

4.10.1.3. Multiple Regions Identified for External Corrosion

If more than one ECDA region was identified as likely for external corrosion in the Pre-Assessment step, one additional direct examination shall be performed within each of the regions identified.

4.10.2. Immediate Action Required

All immediate indications shall be scheduled for direct examination.

4.10.3. Scheduled Indications Identified

A minimum of one direct examination shall be performed at the most severe scheduled indication identified in each ECDA region. The most severe indication shall be based on indirect inspection data, historical corrosion records, and current corrosive conditions.

4.10.3.1. First Assessment Requirement

4.10.3.1.1. When ECDA is applied for the first time, one additional direct examination shall be performed in each ECDA region containing scheduled indications.

4.10.3.1.2. If a region contains only one scheduled indication, then the additional direct examination shall be at a monitored indication (or an indication as likely for external corrosion if no monitored indications exist).

4.10.3.2. Additional Excavation Requirements

At least one additional direct examination shall be performed within the same region(s) if the following two conditions occur:

4.10.3.2.1. The external corrosion results of a direct examination are deeper than 20% of the original wall thickness; **and**

4.10.3.2.2. The indication is deeper or more severe than an immediate indication within the same region.

When ECDA is applied for the first time, one additional direct examination shall be performed within the region(s).

4.10.4. Monitored Indications Identified

If an ECDA region contains monitored indications and the ECDA region did not contain any immediate or scheduled indications, one direct examination shall be performed at the most severe indication.

4.10.4.1. First Assessment Requirement

When ECDA is applied for the first time, one additional direct examination shall be performed.

4.10.4.2. Multiple Regions Identified for External Corrosion

If multiple ECDA regions contain monitored indications and did not contain any immediate or scheduled indications, one direct examination is required in the ECDA region identified as most likely for external corrosion in the Pre-Assessment step.

4.10.4.2.1. When ECDA is applied for the first time, one additional direct examination shall be performed.

4.10.5. ECDA Effectiveness Digs

At least one additional direct examination at the most severe remaining indication shall be performed to provide additional confirmation that the ECDA process has been successful.

4.10.5.1. First Assessment Requirement

When conducting ECDA for the first time over a pipeline segment, an additional effectiveness dig shall be performed at a randomly selected location where no indication was detected.

4.10.5.2. Evaluation

The excavation site shall be assessed per the requirements in §4.11, §5.2 and §5.3. The effectiveness dig shall be repeated, or an alternate integrity assessment method shall be used if conditions exist as specified below:

4.10.5.2.1. Scheduled indication is evaluated as an immediate condition.

4.10.5.2.2. Monitored indication is evaluated as a scheduled condition.

4.10.6. Third Party Damage Indications

The number of excavations shall be determined on a project specific basis by the IE and EPM. Indications will be investigated in order of susceptibility ranking although it is not necessary to excavate all indications that have the potential for third-party damage.

4.10.7. Special Condition

Selected excavations may also include sites for the installation of additional ETS monitoring points as part of on-going preventative and mitigative measures.

4.10.8. Documentation

The IE shall document the indications that have been selected for excavation on the DIRECT EXAMINATION SHEET. The locations shall be reviewed and approved by the EPM and IE. At this stage, the DIRECT EXAMINATION SHEET is preliminary and shall only be distributed to the Data Management Group for field verificaiton after the completion of the Indirect Inspection Meeting.

Table 4.10: Excavation Summary Table

<table>
<tr><th colspan="2">STEP #1
For Each ECDA Segment</th><th colspan="2">STEP #2
Required Excavations For Each ECDA Region</th><th>STEP #3
Effectiveness Digs</th></tr>
<tr><th>Containing</th><th>Action</th><th>Containing</th><th>Action</th><th>Action</th></tr>
<tr><td rowspan="4">Mixed Indications</td><td rowspan="4">1) Separate results by region.
2) Determine region specific excavations.</td><td>Immediates Only</td><td>Dig all Immediates[6]</td><td rowspan="6">Add one (1) excavation per <u>ECDA segment</u> at the most severe indication remaining[7]</td></tr>
<tr><td>Immediates
— AND —
Other Indications</td><td>Dig all Immediates
Plus
Add one (1) dig at the most severe indication[7]</td></tr>
<tr><td>Scheduled Only
— OR —
Scheduled & Monitored</td><td>Dig the most severe Scheduled indication[7]</td></tr>
<tr><td>Monitored Only</td><td>Dig the most severe indication[7]</td></tr>
<tr><td>Monitored Only</td><td>1) Identify region most likely to corrode.
2) Determine excavations for the regions above.
3) No other regions require excavation.</td><td colspan="2">Dig the most severe indication[7]</td></tr>
<tr><td>No Indications</td><td>1) Identify region most likely to corrode.
2) Determine excavations for the regions above.
3) No other regions require excavation.</td><td colspan="2">Dig the location most likely to corrode[7]</td></tr>
</table>

[6] For the first application of ECDA, add a second excavation within the same region at the location most likely to corrode.
[7] For the first application of ECDA, add a second excavation at a randomly selected location containing no indications.

4.11. Scheduling Excavations

4.11.1. Excavation Timeframes

Excavations required as part of Direct Examination should be conducted within 180 days after indirect inspection. The 180 day timeframe is measured from the indirect inspection completion date to the final field activity related, not including repairs, to Direct Examination. Suggested timeframes for Direct Examinations are provided in Table 4.11. Effectiveness Digs may be completed beyond the 180 day Direct Examination schedule requirement.

Table 4.11: Required Excavation Timeframes

Direct Examination Priority	Suggested Timeframe (Months)
Immediate	4
Scheduled	4-6
Monitored	6

4.11.2. Order of Excavations

The IE shall consider the overall risk of the pipeline segments and determine the general order of excavations.

4.11.2.1. Direct Examination Prioritization Groups

The IE shall schedule the excavations in priority groupings per the guidance in Table 4.8.

4.11.2.2. Excavations within Prioritization Groups

The order of excavations within each Priority Group shall be based on the severity of elements which affect the Urgency Criteria detailed in §3.8, the consequence of rupture, and other relevant risk factors deemed significant by the IE.

For cased pipe segments, the IE shall consider the severity of indications, vintage and operating stress.

4.11.3. Excavation Identifier

The name shall include the year inspection (e.g. close-interval, DCVG and ACA surveys) was performed, ECDA segment number, ECDA region number and examination number. The name shall have the following format:

[YYYY]S#R#E#

Where “YYYY” is the placeholder for the four-digit inspection year, “S#” is the ECDA segment number, "R#" is the ECDA region number and "E#" is the examination number.

EXAMPLE: The aboveground surveys for Pipeline 789 were performed in 2013. The name for Examination #8 in ECDA region 1 of ECDA segment 2 would be 2013S2R1E8.

4.11.4. Exceptions

If the 180 day schedule requirement in §4.11.1 is not met due to seasonal restrictions, weather, permitting, supply interruptions, and other issues that impact scheduling direct examinations and repairs, the EPM shall document the procedural deviation in accordance with the Exception Process in §7.0.

In such cases, the delays interrupting continuing progress shall be documented; including a plan to implement appropriate additional precautions (if necessary) to assure pipeline integrity until the direct examinations can be completed.

4.11.5. Direct Examination Sheet

Once direct examination locations have been selected, the EPM shall submit the preliminary DIRECT EXAMINATION SHEET (and associated waypoint files) to the Data Management Group for field verification. The Data Management Group shall locate the excavation sites and complete Bell Hole Siting Reports for each location.

4.12. Indirect Inspection Report

The IE shall complete a report that summarizes the indirect inspection results, the locations selected for examination and identification of inspection gaps. The information contained within this report shall be communicated to all stakeholders.

The completed report will be reviewed by the AM to check for completeness and verify that the inspection gaps do not exceed 5% of the total inspection length.

4.13. Indirect Inspection Meeting

4.13.1. Objective

To communicate the results of the Indirect Inspection Step and present preliminary direct examination sites. The objective of this meeting is also to incorporate feedback from critical personnel to determine if improvements are needed in the identification and classification of indirect inspection results.

4.13.2. Agenda

The meeting shall be coordinated by the EPM and the IE shall present indirect inspection results and the locations selected for examination.

The AM and appropriate operating personnel shall also be invited to participate as necessary to facilitate the survey data review and provide insight into the selected dig locations.

4.13.3. Results

A roster of participants and meeting notes/minutes should be documented in the project file.

5. DIRECT EXAMINATION

5.1. Objectives

To validate the prioritization of indications and their severity. The Direct Examination Step includes the following tasks:

5.1.1. Excavating the indications and collecting data at areas where corrosion activity is most likely occurring;

5.1.2. Measurement of coating damage and corrosion defects;

5.1.3. Evaluation of the remaining strength of the pipe segment;

5.1.4. Root cause analysis;

5.1.5. Reprioritization and reclassification of indications, if necessary;

5.1.6. Remedial actions as necessary.

5.2. Pipe Excavation and Data Collection

5.2.1. Procedure

The pipe shall be excavated in accordance with **Gas Standard 184.0175** and **Gas Standard 223.0140**.

The TPM shall identify the appropriate environmental procedures to use depending upon the nature of the work being performed. Additional guidance is available in **Manual TIMP.11**.

5.2.1.1. Bell Hole Inspection Reports

The IE shall create a BELL HOLE INSPECTION REPORT within the Bell Hole Inspection Database for each excavation selected in accordance with §4.10 of this procedure.

The IE shall complete the "Identification" and "Background" sections of each newly created inspection report, export each report from the database and provide the exported ".txt" file(s) to the IP.

5.2.1.2. Location and Size of Excavation

The location and size of the excavation site shall be identified and recorded on the BELL HOLE INSPECTION REPORT. The center of each excavation shall be located and recorded with a GPS sub-meter instrument.

The ECDA standard length of exposed pipe is 15 feet (7.5 feet on either side of the excavation center). The final exposed pipe length shall be physically measured and recorded.

During baseline assessments, the EPM may reduce the length of the excavation to 10 feet for randomly selected Effectiveness Dig where no indications were detected.

5.2.1.3. Expansion of Excavation

The EPM shall have the excavation expanded in length if it appears that the original IIT indication may be contained in the portion of pipeline buried beyond the boundaries of the excavation.

The EPM shall consider the size of the anomaly detected, the tolerance of the IIT used, and the history of the pipeline segment in making this judgment. Coating or external corrosion anomalies extending into the buried portion of pipeline shall be given special consideration.

The EPM shall be contacted if the expansion of the excavation becomes excessive. The expansion shall be documented on the BELL HOLE INSPECTION REPORT.

5.2.1.4. Qualified Personnel

Pipe shall be inspected by personnel that are qualified by the SoCalGas Operator Qualification Program (**Gas Standard 167.0100**) for the performance of the task ("Examining Buried Pipe when Exposed"). The qualified individual shall complete the BELL HOLE INSPECTION REPORT provided by the IE.

5.2.1.5. Data Collection

Collecting data on the coating and pipe condition is a key step of the ECDA process. The collection of data shall follow the applicable section of **Gas Standard 167.0211**. ECDA specific data collection requirements before and after coating removal are identified in Tables 5.1 and 5.2 below.

5.2.1.6. First Assessment Requirement

When conducting ECDA for the first time over a pipeline segment, Non-Destructive Evaluation (NDE) of all exposed welds shall be performed using methods such as Magnetic Particle Inspection (MPI), Shear Wave, Ultrasonic Testing (UT) or radiography during initial assessments.

Table 5.1: Excavation Data Collection Requirements Before Coating Removal

Data Type	Need[8]	Description
Measurement of Pipe to Soil Potential	R	These measurements shall be performed in accordance with NACE Standard TM0497. The reference electrode shall be placed in the bank of the excavation and/or at the ground surface. These potentials may help identify dynamic stray currents and prove IR drop considerations.
Soil Sample	R	Soil immediately adjacent to the pipe surface may be collected and placed in 2 one gallon zip-loc type bags, with as much air displaced as possible. Record the sample location on the bag.
Ground Water Sample	D	Take ground water sample if water is present. Water should be collected from the open ditch when possible. Completely fill the plastic jar and seal and identify location as described above.
Coating Sample	D	A coating sample may be obtained if the coating is partially or fully disbonded to determine the electrical/ physical properties of the coating and to perform microbial tests.
Liquid pH Analysis	R	If any liquid is detected underneath the coating the pH shall be determined with pH litmus tape.
Confirmation/ Identification of Coating Type	R	Confirm and classify coating type with Pre-Assessment data.
Assessment of Coating Condition	R	Documentation of general coating condition. Three conditions could exist: (1) Coating is in excellent condition and completely adhered to pipe. (2) Coating partially disbonded and/or degraded. (3) The coating is completely missing and the pipe surface is bare.
Measurement of Coating Thickness	D	Measurements shall be taken to determine the thickest and thinnest coating locations throughout the bell hole to obtain representative coating thickness.
Assessment of Coating Adhesion	R	Visual observation to identify sagging and hollow locations in the coating.
Mapping of Coating Degradation	R	Mapping of coating flaws (blisters, disbondment, etc.) to support corrosion evaluation.
Corrosion Product Data Collection	D	Carefully remove any corrosion deposit for possible root cause analysis.
Photographic Documentation	R	Document the coating condition with digital camera. Photos shall have ruler or other device to determine magnification of photographs showing details of the pipe and coating condition. Macro as well as perspective views shall be recorded.

[8] R = Required, D = Desired

Table 5.2: Excavation Data Collection Requirements After Coating Removal

Data Type	Need[9]	Description
Pipe Temperature	D	Measure the bare pipe surface temperature in the shade.
Longitudinal Seam Identification	R	The type of weld seam shall be identified and recorded.
Other Damage	R	Other damage to the pipe surface that can be visually detected shall be recorded. Examples of such damage would include gouges, cracking, dents and out of roundness.
Identification of Corrosion Defects	R	Careful examination of the pipe surface shall be conducted after cleaning to assess the corroded surface.
UT Wall Thickness Measurements	R	Ultrasonic wall thickness measurements shall be taken at every quadrant on the pipe to establish original/nominal wall thickness. Special consideration for internal corrosion shall be taken during measurement and documentation of the wall thickness at the 6:00 position.
Photographic Documentation of Corroded Area	R	The corroded surface shall be photographed to document the corrosion morphology.
Mapping and Measurement of Corrosion Defects	R	Corrosion damage shall be measured sufficiently to enable accurate remaining strength analyses of the corrosion area. A grid of wall loss measurements shall be oriented so that columns are circumferentially oriented on the pipe and rows lie parallel to the longitudinal axis of the pipe. The grid size should be sufficiently fine to document the variation of wall loss.
Pit Depth Map	R	Record the pit depths of the corroded area in a format compatible with RSTRENG or KAPA.
Magnetic Particle Inspection (MPI)	R	Magnetic particle inspection of all exposed welds shall be performed. For additional requirements, see **Gas Standard 167.0211**.

[9] R = Required, D = Desired

5.3. Remaining Strength Evaluation

5.3.1. Objective

5.3.1.1. To determine the predicted burst pressure at the corroded area and assure it meets the Area Class Location Design Requirements.

5.3.1.2. Provide input for the reprioritization process to evaluate if remaining indications are appropriately prioritized.

5.3.1.3. Provide input for establishing reassessment intervals during the Post Assessment Step of this procedure.

5.3.2. Discovery of Potential Integrity Conditions

"DISCOVERY" must be declared immediately upon completion of Direct Examination when a condition which may affect the structural integrity of the pipeline has been found.

If unusual circumstances indicate the need to delay declaration of "DISCOVERY", an action plan must be initiated to obtain enough information to support a determination of the integrity condition. The entire process, including the circumstances involved with the delay and general timeframes for key decisions shall be documented in the project file.

5.3.3. Predicted Burst Pressure Procedure

The IE shall calculate the failure pressure for each corroded area in accordance with **Gas Standard 182.0050**. Other analytical techniques such as linear elastic fracture mechanics may be used as appropriate with approval by the AM.

5.3.3.1. Determination Timeframe

Determination of integrity conditions shall be made as soon as practicable after discovery of a potential integrity condition, but **no later than 5-working days (excluding Saturday, Sunday or federal holidays) after the day the condition is discovered**.

5.3.3.2. Documentation

Documentation regarding both discovery and determination of integrity conditions is the responsibility of the IE. Determinations conducted through RSTRENG or KAPA analyses shall be attached as a separate supporting document.

5.4. Required Action for Integrity Conditions

5.4.1. Remediation Requirements

The IE shall determine the applicable remediation requirements in accordance with Gas **Standard 167.0236**.

5.4.2. Notification

The IE shall immediately contact the EPM (primary notification) and AM (secondary notification) if any of the following conditions exist:

5.4.2.1. The Corroded Area Safety Factor (SF_{CORR}) is less than the Design Required Safety Factor (SF_{DR}) specified for the class location;

5.4.2.2. Immediate response conditions exists in accordance with **Gas Standard 167.0235**;

5.4.2.3. A reportable safety-related condition exists in accordance with **Gas Standard 183.06**.

5.4.3. Documentation

The EPM shall ensure that remedial actions are documented according to §5.3.3.2 of this procedure.

5.5. Root Cause Analysis

5.5.1. Objective

To identify the likely causes of corrosion or pipe damage to determine:

5.5.1.1. If ECDA is suitable for finding the degradation mechanism;

5.5.1.2. The likelihood that similar corrosion damage will occur elsewhere in the ECDA region;

5.5.1.3. If the degradation is from a historic or active mechanism; and

5.5.1.4. How to mitigate the degradation.

5.5.2. Process

The IE shall perform a root cause analysis for each indication associated with a significant external corrosion condition or other form of pipe damage which affects the MAOP of the pipeline.

5.5.3. Analysis Content

The analysis should discuss the following aspects:

5.5.3.1. Coating Failure

The extent and cause of coating failure, including discussion regarding whether the damage is localized or widespread.

5.5.3.2. Cathodic Protection Ineffectiveness

Why the CP was ineffective in this area. Include a discussion of CP history in the area and the reasons for the presence of CP current

5.5.3.3. Corrosion Mechanism

Identify the main drivers for corrosion in the area including soil chemistry, pH, moisture, corrosive microbes, etc. Is the corrosion active or historic?

5.5.3.4. Degradation in Other Areas

Discuss the characteristics of other locations where similar corrosion may be. Discuss the likelihood if the corrosion is active or historic.

5.5.3.5. Mitigative Measures

Identify potential mitigative measures to impede or arrest corrosion at the locations which contribute to the root cause.

5.5.3.6. ECDA Feasibility

Discuss the suitability and potential success of applying the ECDA process to similar areas of degradation.

5.5.4. Documentation

The root cause of significant corrosion conditions shall be documented on FORM E – ROOT CAUSE ANALYSIS. A root cause analysis may cover multiple conditions provided that they are similar in all the characteristics listed in §5.5.3.

5.5.5. Other Damage Mechanisms

If the root cause analysis identifies a degradation mechanism that the ECDA process is not well suited to detect, (e.g. - this includes corrosion caused by disbonded shielding coatings, long seam threats, etc.), a report to file shall be generated by the IE to document the causal factors. The following topics shall be addressed in the report:

5.5.5.1. The mechanism or adverse conditions that made the ECDA infeasible or invalid; and

5.5.5.2. A conclusion regarding the feasibility of conducting ECDA for the pipeline segments in the project.

For mechanisms which ECDA is not feasible, the process for selection of a suitable assessment method shall be initiated by the EPM in accordance with **Manual TIMP.14**

5.5.6. Corrective Action

Corrective actions taken to address the root cause during the detailed examination shall be documented on FORM E.

5.6. ECDA Region Review

5.6.1. Process

The ECDA region designations established during the Pre-Assessment step shall be reviewed and verified by the IE based on results from the Direct Examination Step, including but not limited to the findings from Root Cause Analysis. Any required changes shall be completed prior to Reclassification and Reprioritization of Indications.

5.6.2. Documentation

The IE shall document changes in ECDA region boundaries on FORM C or equivalent documentation.

5.7. Reclassification and Reprioritization of Indications

5.7.1. Criteria Assessments

5.7.1.1. Classification Criteria

The IE shall assess the corrosion activity at each excavation relative to the criteria used to classify the severity of the indication. If external corrosion activity is less severe than classified in §4.7, the IE may modify the criteria and/or reclassify all indications.

However, if corrosion activity is more severe than classified and the condition is anticipated at other locations over a pipeline segment, the IE shall modify the criteria according to §5.7.3. In addition, the IE shall consider the need for additional indirect inspections and the adjustment of prioritized indications.

5.7.1.2. Prioritization Criteria

The IE shall assess the extent and severity of existing corrosion relative to the assumptions made in establishing priority categories.

If external corrosion is less severe than prioritized in §4.9, the IE may modify the criteria and/or reclassify all indications.

If external corrosion is more severe than prioritized and the condition is anticipated at other locations over a pipeline segment, the IE shall modify the criteria and reprioritize all indications according to §5.7.4.

5.7.2. First Assessment Requirement

When conducting ECDA for the first time over a pipeline segment, the classification and prioritization criteria shall not be downgraded.

5.7.3. Reclassification Criteria

If external corrosion is more severe than classified and the condition is anticipated at other locations over a pipeline segment, the IE shall apply one of the following options:

5.7.3.1. Modify Table 4.3 by changing the criteria for a "Severe" indication from -500mV to -550mV, or

5.7.3.2. Use an alternative method reviewed and approved by the AM.

The IE shall document the reclassification of all indications on Form D or equivalent documentation.

5.7.4. ECDA Feasibility Assessment

If repeated direct examinations show corrosion activity that is worse than indicated by the indirect inspection data, the IE shall reevaluate the feasibility of successfully using ECDA.

5.7.5. Reprioritization Criteria

Reprioritization is required if the corroded area is more severe than its assigned priority. The prioritization shall be increased to the next highest priority. The IE shall apply the following requirements to the reprioritization of indications.

5.7.5.1. When an indication's priority is raised, the IE shall reevaluate other indications that may have similar root causes in the ECDA region.

5.7.5.2. All reprioritized indications shall follow the excavation criteria for the new priority in accordance with §4.10 of this procedure.

5.7.5.3. If Immediate indications are found to be more severe than the criteria in Table 5.3, no other Immediate indication within that ECDA region shall be reprioritized to a lower priority.

5.7.5.4. An indication that was originally prioritized as an Immediate indication should be prioritized no lower than a Scheduled indication as a result of reprioritization.

5.7.5.5. If remediation is performed on an Immediate Indication it may be revised to Scheduled provided subsequent indirect inspections justify reducing the severity.

5.7.5.6. If remediation is performed on a Scheduled indication, it may be revised to Monitored if no corrosion is found.

Once indications have been reprioritized, additional excavations may be required. The IE shall ensure the excavation requirements in §4.10 have been met for each ECDA region designation.

5.7.6. First Assessment Requirement

When conducting ECDA for the first time over a pipeline segment, Immediate and Scheduled indications shall not be reprioritized to a lower priority category.

5.7.7. Documentation

The IE shall document additional excavations on the DIRECT EXAMINATION SHEET (or equivalent) and all reprioritized indications on FORM F: REPRIORITIZATION.

Table 5.3: Reprioritization Criteria by Class Area[10,11]

Class Location	SF_{CORR} Requirements for Priority Categories			
	Immediate	Scheduled	Monitored	NRI
1	≤1.1	<1.39	>1.39 with corrosion	Corrosion <20%
2	≤1.1	<1.67	>1.67 with corrosion	Corrosion <20%
3	≤1.1	<2.00	>2.00 with corrosion	Corrosion <20%
4	≤1.1	<2.50	>2.50 with corrosion	Corrosion <20%

[10] The table complies with the criterion listed in DOT 192.933.

[11] Both immediate and scheduled conditions require repair and/or remediation during the direct examination process.

5.8. Direct Examination Report

The IE shall complete a report that summarizes the direct examination results. The information contained within this report shall be communicated to all stakeholders.

5.9. Assessment Completion Verification

The AM, EPM and IE shall review and validate the results of the Direct Examination step to verify the completed mileage for assessment reporting. Prior to meeting, the IE shall:

5.9.1. Ensure bell hole data for all scheduled excavations has been submitted, verified and imported into the Bell Hole Inspection database;

5.9.2. Update the Performance Metrics spreadsheet;

5.9.3. Ensure ECDA Forms A through F have been completed and signed by appropriate personnel.

5.9.4. Document the extents of the assessment in accordance with **Form ACF**. The completed form, including identification of inspection gaps will be reviewed by the AM to check for completeness.

5.9.5. Complete **Form 2112** for updating the HPPD (if applicable).

5.9.6. Complete **Form F4-1** for changes in threats analyzed during ECDA in accordance with **Gas Standard 167.0203** (if applicable).

5.10. Direct Examination Meeting

5.10.1. Objective

To communicate the completion of ECDA field activity to operating personnel and communicate results to the Preventative & Mitigative Measures Team to initiate development of P&M measures. Also, to utilize feedback from attending personnel to improve the overall objectives of the Direct Examination step.

5.10.2. Agenda

The meeting shall be coordinated by the EPM and the IE shall present the results of the direct examination step.

The IE, AM, P&M Team representative, and appropriate operating personnel shall also be invited to participate as necessary to facilitate the review of Direct Examination results.

5.10.3. Results

A roster of participants and meeting notes/minutes should be documented in the project file.

6. POST ASSESSMENT

6.1. Objectives

To determine the remaining life and reassessment interval for an ECDA region, and assess the overall effectiveness of the ECDA process.

6.2. Corrosion Rate Determination

6.2.1. Objective

To estimate the corrosion rate of specific ECDA regions to support the remaining life calculation.

6.2.2. Process

The IE shall use one of the following methods to estimate corrosion rates:

6.2.2.1. Default Corrosion Rate

In the absence of supporting data, a default rate of 16 mpy should be used to establish the reassessment interval. However, the default rate may be reduced to 12 mpy provided it can be demonstrated that the ECDA region(s) under evaluation have maintained:

6.2.2.1.1. At least 40 mV of polarization (considering IR drop), and

6.2.2.1.2. An Urgency Level B or C.

6.2.2.2. Corrosion Rates Based on Soil Resistivity

Corrosion rates listed in Table 6.1 may be assigned when soil resistivity measurements are taken during the bell hole inspection process.

Table 6.1: Corrosion Rates Related to Soil Resistivity[12]

Corrosion Rate (mpy)	Soil Resistivity (Ohm-cm)
3	>15,000 + no known active corrosion.
6	1,000 – 15,000 and/or known active corrosion
12	<1,000 (worst case)

6.2.2.3. Corrosion Rate Modeling

The corrosion rate obtained through the integration of environmental characteristics shown in Table 6.2 and cathodic protection data may be used for determining corrosion rates.

Table 6.2: Soil Analysis Data Elements

Chemical
Soil Resistivity
pH
Cl
Ca
K
SO_4

Grain Size
% Gravel
% Sand
% Silt
% Clay

6.2.2.4. Corrosion Rate Exceptions

Other corrosion rates that are scientifically supported may also be used. The AM shall approve the use of alternative corrosion rates.

6.3. Remaining Life Determination

The IE shall calculate the remaining life of a corroded area by applying a corrosion rate (either measured or assumed) to the corroded area that exhibits the lowest predicted burst pressure.

6.3.1. Corroded Area Dimensions

The dimensions of the indication with the lowest burst pressure (P_f) in a given ECDA region shall be used to determine remaining life.

12 ASME B31.8S 2004, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines*, pg. 57, Table B1.

6.3.1.1. Root Cause Exception

If the root cause analysis shows that the weakest corroded area is unique (and therefore not representative of the dominant degradation mechanism), then the next weakest corroded area may be used to determine remaining life.

6.3.2. Calculation

The remaining life shall be calculated for the most severe integrity condition exposed during Direct Examination for each ECDA region. This includes all excavated imperfections and defects which had initially been prioritized as immediate, scheduled or monitored indications.

$$RL = \frac{0.85}{\text{Yield Pressure}} \times \left[\left(P_f - MAOP\right)\left(\frac{t}{CR}\right) \right]$$

Where,

RL = Remaining Life (years)
P_f = Burst Pressure from RSTRENG or KAPA (psi)
MAOP = Maximum Allowable Operating Pressure (psi)
t = Wall Thickness (inches)
CR = Corrosion Rate (inches/year)
Yield Pressure $= \frac{2 \times SMYS \times t}{OD}$ (psi)
SMYS = Specified Minimum Yield Strength (psi)
OD = Outer Diameter (inches)

6.3.3. Documentation

The IE shall document the remaining life on FORM G: REMAINING LIFE DETERMINATION.

6.4. Reassessment Intervals

6.4.1. Establishing Reassessment Intervals

The suggested reassessment interval for an ECDA region shall not exceed one-half of the shortest remaining life calculated in §6.3.2. This recommendation is submitted to the Preventive and Mitigative Measures (P&M) Group to establish a final reassessment interval in accordance with **Gas Standard 167.0215**.

6.4.1.1. Pipelines Over 50% SMYS

In accordance with ASME B31.8S-2004, the maximum reassessment interval for lines containing pipe segments operating at or above 50% of the SMYS shall be 5 years.

6.4.2. Other Governing Codes and Regulations

Other documents such as PHMSA regulations may provide further limitations on the reassessment intervals.

6.4.3. Documentation

The IE shall document the reassessment interval for each ECDA region on FORM G – REMAINING LIFE DETERMINATION. FORM G shall be reviewed and signed by the EPM and IE.

6.5. ECDA Performance Report

The EPM shall complete Form H – ECDA Performance Report to record information that will be used for the assessment of ECDA effectiveness as described in §6.6. A brief description of the items recorded on the form is provided below.

6.5.1. Survey Completion Date – Record the date the indirect inspections were completed.

6.5.2. Indirect Inspection Report – Record the date the indirect inspection report and survey data were submitted by the vendor.

6.5.3. Prioritization of Indications – Record the dates when indications were prioritized. Also record the number of indications by priority in the table.

6.5.4. Number of Excavations – Record the number of excavations for each priority indication.

6.5.5. Reprioritization – If indications were reprioritized as more severe, record the number of indications that were reprioritized. Indicate the reason for reprioritization (i.e. due to effectiveness dig results, due to direct examination results).

6.5.6. Exception Reports Documented – Record the number of exceptions taken that resulted in a procedural change and briefly describe the nature of each exception.

6.6. Assessment of ECDA Effectiveness

6.6.1. Objective

To facilitate the collection and integration of Performance Metrics data and describe how the results are used to analyze the long term effectiveness of the ECDA processes and procedures. This effort is necessary to identify, evaluate, and implement continuous improvement strategies.

6.6.2. Process

FORM H will be the primary source of data for monitoring the effectiveness of ECDA. The performance metrics to be tracked and the frequency for review are provided in Table 6.3.

The AM will be responsible for conducting trend analyses in order to identify areas for performance improvement. The results of the analyses will be used to determine the best approach for improvement in each program area shown in the “Applicability” column of Table 6.3.

Recommendations will be reviewed with ECDA team members in order to determine the efficacy of the recommendations and identify implementation requirements (time required, resources needed, extent of processes and procedures to be revised, training, etc.). The adoption of final recommendations will be documented.

6.6.3. Documentation

The data will be looked at periodically to identify performance trends. Improvements will be performed as necessary and the results will be communicated.

Table 6.3: ECDA Effectiveness Measures

Measure	Frequency	Applicability
Track the number of projects where the use of the ECDA methodology was determined to be infeasible.	Annual	Continuous improvement evaluation with respect to ECDA feasibility and IIT applicability. Measure will be documented on Form H.
Track the number of indications that were reprioritized as more severe due to Direct Examination results.	Annual	Evaluation of the conservatism of the ECDA Program. Measure will be documented on Form H.
Track the number of Effectiveness Digs that have resulted in a reduction in the reassessment interval to less than 7 years.	Annual	Continuous improvement evaluation with respect to ECDA feasibility and IIT applicability. Determine if the grading protocols established for indirect inspection data are adequate. Measure will be documented on Form H.
Track the number of exception reports that resulted in procedural changes.	Annual	Evaluation of the effective application of the ECDA processes and procedures. Exceptions should decrease over time as the program evolves. Measure will be documented on Form H.

7. EXCEPTION PROCESS

It is expected that all requirements of this procedure be met when conducting an ECDA. However, exceptions may be taken by obtaining approval and documenting the exceptions as prescribed in this section.

Note: Exceptions shall not be granted for mandatory requirements listed as part of 49 CFR 192 or ANSI/NACE SP0502 without the prior consent of the appropriate jurisdictional regulatory authority.

7.1. Objective

To provide control and consistent documentation of deviations from this procedure. Control and consistent documentation are necessary to maintain the integrity of an ECDA project through continuous process improvement, feedback, audits, and compliance with this procedure.

7.2. Requirements

The following process is required when deviating from this procedure:

7.2.1. Section of Procedure

State the specific paragraph number where the exception is being taken.

7.2.2. Reason

Provide the reason for the exception.

7.2.3. Alternative Plan

State the proposed exceptions to the procedure.

7.2.4. Recommendation

Indicate if this is a project specific exception, or if a procedure change is recommended. The criteria and internal notification procedures for republishing this gas standard shall follow the Management of Change Process referenced in Sections 2.3.1.

7.2.5. Approval

Obtain approval from the AM.

7.3. Documentation

FORM I: EXCEPTION REPORT shall be used to document the Exception Process. The completed form shall be reviewed and approved by the EPM, IE, and AM. The results will be updated and tracked in the applicable Performance Metrics spreadsheets. All exception reports shall be stored in the ECDA project file.

8. CROSS REFERENCE

ECDA Procedure		SP0502	49 CFR 192	
Section	Name	Section	Section	Paragraph
1. Purpose				
2. Introduction				
2.1	References			
2.2	Objective	1.1.4	192.923(a) & (b)	How is direct assessment used and for what threats?
2.3	Policy & Scope	1.1.5	192.923(a) & (b)	How is direct assessment used and for what threats?
2.4	ECDA Methodology	1.2	192.925 (a) & (b)	What are the requirements for using External Corrosion Direct Assessment (ECDA)?
2.5	Roles & Responsibilities	1.1.11		
2.6	Qualifications	1.1.11	192.915(a), (b) & (c)	What knowledge and training must personnel have to carry out an integrity management program?
2.7	Definitions	Section 2: Definitions		
2.8	Special Requirements	1.2.3		
3. Pre-Assessment				
3.1	Objectives	3.1.1		
3.3	Data Collection	3.2		
3.3.2	Data Requirements	3.2.1.1		
3.3.3	First Assessment Requirement	3.2.1.2	192.925(b)(1)(i)	**Pre-Assessment -** Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment.
3.3.5	Data Sources	3.2.2		
3.3.8	Documentation	3.2.1, 7.2.1		
3.3.9	Project Document File	7.1		
3.4	Sufficient Data Analysis	3.2.4, 7.2.1		
3.5	Feasibility Analysis	3.3		
3.5.1	Objective	3.3.1 - 3.3.3		
3.5.2	Specific Feasibility Review	3.3.1.1 – 3.3.1.6		
3.5.3	Documentation	7.2.1.2		
3.7	Designation of ECDA Regions	3.5		
3.7.1	Criteria	3.5.1.1.2		
3.7.2	Description	3.5.1.1.1		
3.7.3	Documentation	7.2.1.4		
3.8	Urgency Criteria	N/A	192.925 (b)(2)(iii)	**Indirect Inspection** – Criteria for defining the urgency of direct examination of each indication identified during indirect inspection.
3.9	Indirect Inspection Tool Selection	3.4		
3.9.1	Number of Indirect Inspection Tools	3.4.1		
3.9.2	Selection Basis	3.4.1.1, 3.4.1.2	192.925(b)(1)(ii)	The basis on which an operator selects at least two different, but complementary indirect assessment tools for each ECDA region.
3.9.3	Special Condition	3.4.1.3		
3.9.4	First Assessment Requirement	N/A	192.925(b)(1)(i)	**Pre-Assessment -** Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment.

ECDA Procedure		SP0502	49 CFR 192	
Section	Name	Section	Section	Paragraph
3.9.5	Documentation	7.2.1.3		
3.11	Pre-Assessment Meeting	7.2.1		
4. Indirect Inspection				
4.1	Objectives	4.1.1		
4.2	Indirect Inspection Procedure Review	4.2.2 – 4.2.5	192.925(b)(2)(ii)	**IndirectInspection** - Criteria for identifying and documenting indications that must be considered for excavation and direct examination.
4.2.4	Documentation and Procedure Filing	7.3.1		
4.3	Marking of Inspection Areas	4.2		
4.3.1	Objective	4.2.1		
4.3.2	Process	4.2.1.1, 4.2.2		
4.4.11	Documentation	7.3.1		
4.5.1	Breadth of Inspections	4.2.2		
4.5.1.1	Supplemental Inspections	7.3.1		
4.5.3	Time Between Primary Inspections	4.2.4		
4.6	Indirect Inspection Reporting	7.3.1.2, 7.3.1.3		
4.7	Identification and Classification of Indications	4.3	192.925(b)(2)(ii)	**Indirect Inspection** - Criteria for identifying and documenting indications that must be considered for excavation and direct examination.
4.7.2	Criteria	4.3.1.1		
4.7.3	Documentation	7.3.1		
4.8	Data Alignment and Comparison	4.3.1, 4.3.3, 4.3.4, 7.3.1.4		
4.8.2	Resolution of Data Inconsistencies	4.3.3.1		
4.8.2.1	Preliminary Direct Examinations	4.3.3.1.1		
4.8.2.2	Additional Indirect Inspections	4.3.3.1.2		
4.8.2.3	Classify Indications as Severe	4.3.3.1.4		
4.8.3	ECDA Feasibility Assessment	4.3.3.1.3, 4.3.4.1		
4.9	Prioritization of Indications	5.2, 7.3.1.5		
4.9.2	Initial Prioritization	5.2.1.2		
4.9.2.1	Priority I	5.2.2.1.1 – 5.2.2.1.5, 5.2.3.1		
4.9.2.2	Priority II	5.2.2.2.1 - 5.2.2.2.2		
4.9.2.3	Priority III	5.2.2.3		
4.9.2.4	Priority TPD	N/A	192.917(e)(1)	**Third Party Damage** - If . . . an operator uses . . . ECDA, the operator must integrate data . . . with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage exist in the covered segment.
4.9.3	Prioritization of Excavations	5.2.1 – 5.2.3, 5.2.1.1	192.925(b)(2)(iv)	**Indirect Inspection** - Criteria for scheduling excavation of indications for each urgency level.
4.9.4	Prioritization of Third Party Damage	N/A	192.917(e)(1)	**Third Party Damage** - If . . . an operator uses . . . ECDA, the operator must integrate data . . . with data related to any encroachment or foreign line crossing on the covered segment, to define where potential indications of third party damage exist in the covered segment.
4.9.6	Indirect Inspection Analysis	4.3.4.1		
4.9.7	Documentation	7.3.1.5		

ECDA Procedure		SP0502	49 CFR 192	
Section	Name	Section	Section	Paragraph
4.10	Number of Excavations	5.3		
4.10.1	Immediate Indications	5..3.2		
4.10.2	Scheduled Indications	5.3.3		
4.10.2.1	20% Wall Loss Criteria	5.3.3.3		
4.10.2.2	First Assessment Requirement	5.3.3.3.1		
4.10.3	Monitored Indications	5.3.4		
4.10.3.1	First Assessment Requirement	5.3.4.2.1		
4.10.4	No Indications	5.3.1		
4.10.4.1	First Assessment Requirement	5.3.1.1.1		
4.10.5	ECDA Effectiveness Digs	6.7.2		
4.10.5.1	First Assessment Requirement	6.7.2.1		
4.10.5.2	Evaluation	6.7.2.2		
4.10.8	Documentation	7.4.1		
4.11	Scheduling Excavations	5.4.1	192.933(b)	**Discovery of Condition** – An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.
4.13	Indirect Inspection Meeting	7.3.1		
5. Direct Examination				
5.1	Objectives	5.1.1, 5.1.6		
5.2	Pipe Excavation and Data Collection	5.4		
5.2.1.1	Bell Hole Inspection Reports	7.4.1		
5.2.1.2	Location and Size of Excavation	5.4.1.1, 7.4.1.2		
5.2.1.3	Expansion of Excavation	5.4.3.3, 7.4.1.2		
5.2.1.4	Qualified Personnel	1.1.11		
5.2.1.5	Data Collection	5.4.2, 5.4.3, 5.5, 7.4.1.2		
5.2.1.6	First Assessment Requirement	5.5.3.5, 5.6.2	192.925(b)(3)(i)	**Direct Examination** – Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment.
5.3	Remaining Strength Evaluation	5.6		
5.3.4	Predicted Burst Pressure Procedure	5.6.1		
5.3.4.2	Documentation	7.4.1.2		
5.4	Required Action for Integrity Conditions	5.6.2	192.925(b)(3)(ii)(A)	**Direct Examination** – Criteria for action to be taken if corrosion defects are discovered that exceed allowable limits.
5.4.1	Remediation Requirements	6.4, 7.4.1.2		
5.5	Root Cause Analysis	6.3		
5.5.3	Analysis Content	56.3.1		
5.5.3.4	Degradation in Other Areas	7.4.1.2.2		
5.5.3.5	Mitigative Measures	7.4.1.4		
5.5.4	Documentation	7.4.1.4		
5.5.5	Other Damage Mechanisms	5.1.5, 6.3.2	192.925(b)(3)(ii)(B)	**Direct Examination** – Criteria for action to be taken if root cause analysis reveals conditions for which DA is not suitable.

ECDA Procedure		SP0502	49 CFR 192	
Section	Name	Section	Section	Paragraph
5.5.6	Corrective Actions	7.4.1.4		
5.7	Reclassification and Reprioritization of Indications	6.5	192.925(b)(3)(iv)	**Direct Examination** – Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions specified in section 5.9 of RP0502.
5.7.1	Criteria Assessments	5.7, 5.7.3.1 – 5.7.3.3, 5.7.4.1 – 5.7.4.3, 5.7.4.3.1		
5.7.2	First Assessment Requirement	5.7.4.2		
5.7.3	Reclassification Criteria	5.7.4, 5.7.4.3, 6.5.2	192.925(b)(3)(iii)	**Direct Examination** – Criteria and notification procedures for any changes in the ECDA Plan, including severity classification, priority of direct examination, and the time frame for direct examination.
5.7.3.1	ECDA Feasibility Assessment	5.7.4.4		
5.7.4	Reprioritization Criteria	5.7.3, 6.5.1, 6.5.3 – 6.5.6, 7.4.1.5	192.925(b)(3)(iii)	**Direct Examination** – Criteria and notification procedures for any changes in the ECDA Plan, including severity classification, priority of direct examination, and the time frame for direct examination.
5.7.4.1	First Assessment Requirement	5.7.4.2		
5.10	Direct Examination Meeting	7.4.1		
6. Post Assessment				
6.1	Objectives	6.1.1		
6.2	Corrosion Rate Determination	6.2.3, 7.5.1.1.2		
6.2.2.1	Default Corrosion Rate	Appendix C3.3		
6.2.2.2	Corrosion Rates Based on Soil Resistivity	Appendix C3.2		
6.3	Remaining Life Determination	6.2		
6.3.1	Corroded Area Dimensions	6.2.2, 7.5.1.1.1		
6.3.1.1	Root Cause Exception	6.2.2.1		
6.3.2	Calculation	6.2.2, 6.2.4, 7.5.1.1.3		
6.3.3	Documentation	7.5.1.1.4		
6.4	Reassessment Intervals	6.6	192.939(a)(2)	**What are the required reassessment intervals, External Corrosion Direct Assessment** - An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of RP0502.
6.4.1	Establishing Reassessment Intervals	6.6.1	192.925(b)(4)(ii)	**Post Assessment and continuing evaluation** - Criteria for evaluating whether conditions indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939.

ECDA Procedure		SP0502	49 CFR 192	
Section	Name	Section	Section	Paragraph
6.4.1.1	Pipelines Over 50% SMYS	6.6.1	192.939(a)(2)	**What are the required reassessment intervals, External Corrosion Direct Assessment** - An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of RP0502.
6.4.2	Other Governing Codes and Regulations	6.6.1	192.925(b)(4)(ii)	**Post Assessment and continuing evaluation** - Criteria for evaluating whether conditions indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939.
6.4.3	Documentation	7.5.1.2		
6.5	ECDA Performance Report	6.7.3, 7.5.1.3	192.945(b)	**What methods must an operator use to measure program effectiveness?** - In addition to paragraph (a), an operator using ECDA must define and monitor measures to determine the effectiveness of ECDA.
6.5.1	Survey Completion Date	7.5.1.3.1		
6.5.2	Indirect Inspection Report	7.3.1, 7.5.1.3.1		
6.5.3	Prioritization of Indications	5.1.6.1, 5.2.1.1		
6.5.4	Number of Excavations	6.7.3.2.1, 7.5.1.3.1		
6.5.5	Reprioritization	6.7.3.1, 7.5.1.3.1	192.925(b)(4)(i)	**Post Assessment and continuing evaluation** - Measures for evaluating the long term effectiveness of ECDA in addressing external corrosion.
6.5.6	Exception Reports Documented	7.5.1.3.1, 7.5.1.4		
6.6	Assessment of ECDA Effectiveness	6.7	192.925(b)(4)(i)	**Post Assessment and continuing evaluation** - Measures for evaluating the long term effectiveness of ECDA in addressing external corrosion.
6.6.1	Objective	6.7.3		
6.6.2	Process	6.7.3.1		
6.6.3	Documentation	7.5.1.4		
7. Exception Process				
7.1	Objective	6.8.1, 7.5.1.4		
7.2.4	Recommendation	6.8.1		

9. PROTOCOL REFERENCE

ECDA Procedure		PHMSA Protocol Item		Year of Finding
Section	Name	Item	Description	
3.3.3	First Assessment Requirements	D.03	Verify that the ECDA Indirect Inspection process complies with ASME B31.8S-2004, Section 6.4 and NACE RP0502, Section 4 to identify and characterize the severity of coating fault indications, other anomalies, and areas at which corrosion activity may have occurred or may be occurring, and establish priorities for excavation.	2007
3.3.4	Global Pre-Assessment	D.02.a	Verify that the operator identifies and collects adequate data to support ECDA pre-assessment.	2007
3.5.3	Documentation	D.02.b	Verify that the operator conducts an ECDA feasibility assessment by integrating and analyzing the data collected.	2007
3.7.1	Criteria	D.02.d	Verify that the operator identifies ECDA regions based on the use of data integration results applied to specified criteria.	2007
3.7.2	Description			
3.9.2	Selection Basis	D.02.c	Verify that the operator complies with all requirements for appropriate indirect inspection tools selection.	2007
3.9.4	First Assessment Requirement			
4.3.2	Process	D.03.a.1	Verify that the operator identifies and clearly marks the boundaries of each ECDA region.	2007
4.4.5	Indirect Inspection Tools	D.03.a	Verify that the operator conducts indirect inspection measurements in accordance with NACE RP0502, Section 4.2.	2007
4.8.2	Resolution of Data Inconsistencies	D.03.b.2.2	Verify that the operator compares the results from the indirect inspections and determines the consistency of indirect inspections results to resolve conflicting or differing indications by the primary and secondary tools.	2007
4.8.3	ECDA Feasibility Reassessment	D.03.b.2.3	Verify that the operator compares indirect inspection results with pre-assessment results to confirm or reassess ECDA feasibility and ECDA region definitions.	2007
4.9.6	Indirect Inspection Analysis	D.02.d	Verify that the operator identifies ECDA regions based on the use of data integration results applied to specified criteria.	2007
4.11	Scheduling Excavations	D.04.a.1	Verify that the operator makes excavations based on priority categories described in NACE RP0502, Section 5.2.	2007
5.2.1.6	First Assessment Requirement	D.04.a.2	Verify that the operator identifies and implements minimum requirements for data collection, measurements, and recordkeeping, to evaluate coating condition and significant corrosion defects at each excavation location.	2007
5.4.1	Remediation Requirements	D.04.e	Verify that the operator performs an evaluation of the indirect inspection data, the results from the remaining strength evaluation and root cause analysis to evaluate the criteria and assumptions.	2007
5.5.3.5	Mitigative Measures	D.04.d	Verify that the operator mitigates or precludes future external corrosion resulting from significant root causes.	2007
5.6	ECDA Region Review	D.02.d	Verify that the operator identifies ECDA regions based on the use of data integration results applied to specified criteria.	2007
5.7.4	Reprioritization Criteria	D.04.e.1 D.04.e.2	Verify that the operator performs an evaluation of the indirect inspection data, the results from the remaining strength evaluation and root cause analysis to evaluate the criteria and assumptions used to categorize the need for repairs and classify the severity of individual indications.	2007
6.3.2	Calculation	D.05.a	Verify that the operator determined reassessment intervals in accordance with NACE RP0502, Section 6.	2007
6.4	Reassessment Intervals	D.05.b.1	Verify that reassessment intervals do not exceed the maximum intervals (refer to Protocol F) established in §192.939.	2007

10. APPENDIX A: ECDA FORMS

<table>
<tr>
<td rowspan="2">
INSTRUCTIONS:
Double-click the icon (right) to open a blank version of the forms.
To save the file:
1. Click the “File” Tab and select “Save As” (Figure 1) or the save button on the Quick Access Tool Bar (Figure 2).
2. The file name format should be “[PipelineName]_ECDAForms.xlsm ” (e.g. L41-05_ECDAForms.xlsm).
NOTE: The Excel file may only be opened within the Word document version of this standard.
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<td>

SoCalGas_L#_ECDA
_Forms_Rev6_0_201
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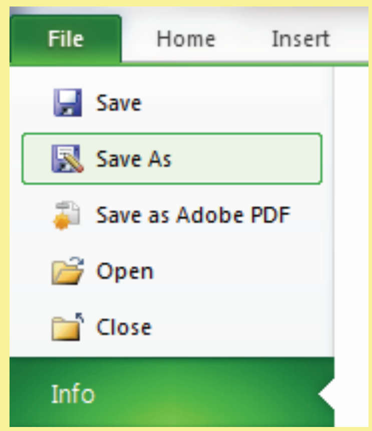


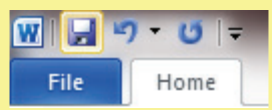
Figure 1


Figure 2
</td>
</tr>
</table>

11. APPENDIX B: ICAM (INTEGRITY COMPLIANCE ACTIVITY MANAGER)

1. The compliance and conformance integrity management processes for ECDA are managed, scheduled, tracked, documented, communicated, and reported in the ICAM quality management platform. This platform captures who, what, when, where, why, and why not information associated with these activities, and provides decision-based routing.

   The flowchart for the ICAM processes for ECDA can be seen in Figure 1 below. Each process (shown as a gray box) has tasks designed to document implementation by capturing decisions and supporting information, managing routing and communications, and supporting conformance and compliance requirements. The flowchart also highlights critical records (shown in yellow) that are used and produced from this area.

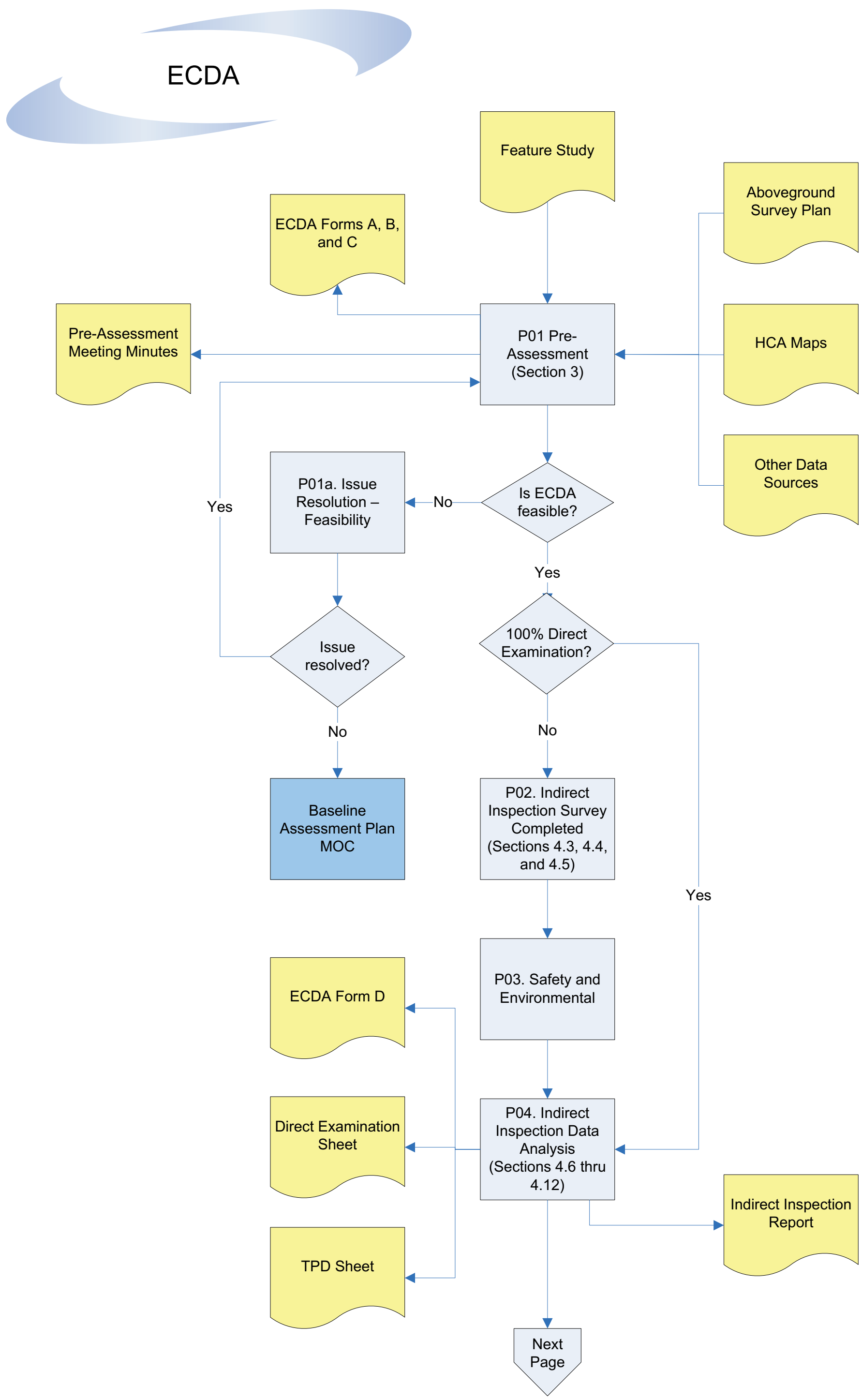

ECDA
Feature Study
Aboveground Survey Plan
ECDA Forms A, B, and C
Pre-Assessment Meeting Minutes
P01 Pre-Assessment (Section 3)
HCA Maps
Other Data Sources
P01a. Issue Resolution – Feasibility
No
Is ECDA feasible?
Yes
Yes
Issue resolved?
100% Direct Examination?
No
No
Baseline Assessment Plan MOC
P02. Indirect Inspection Survey Completed (Sections 4.3, 4.4, and 4.5)
Yes
ECDA Form D
P03. Safety and Environmental
Direct Examination Sheet
P04. Indirect Inspection Data Analysis (Sections 4.6 thru 4.12)
Indirect Inspection Report
TPD Sheet
Next Page

Figure 1

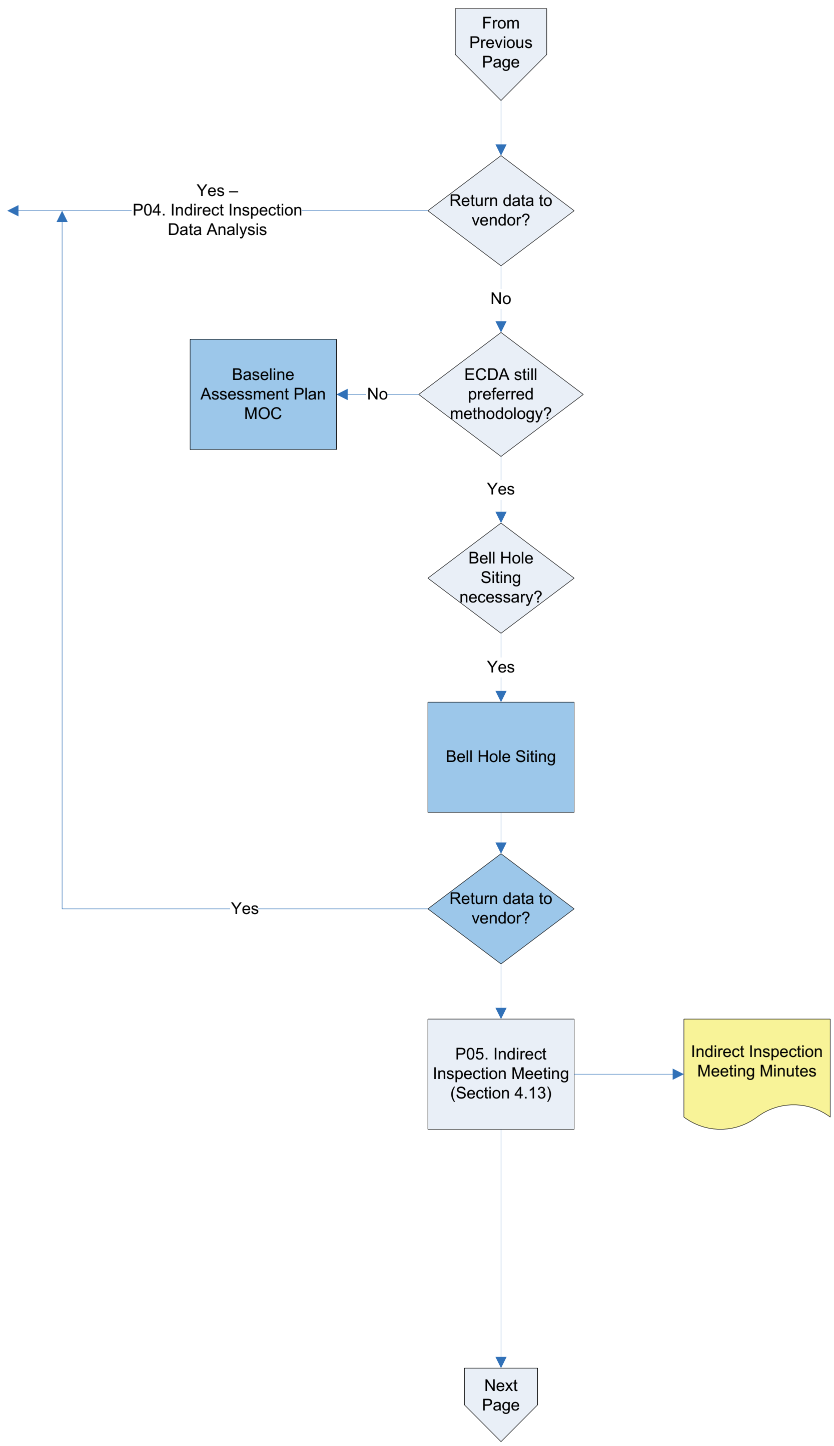


Figure 1, continued

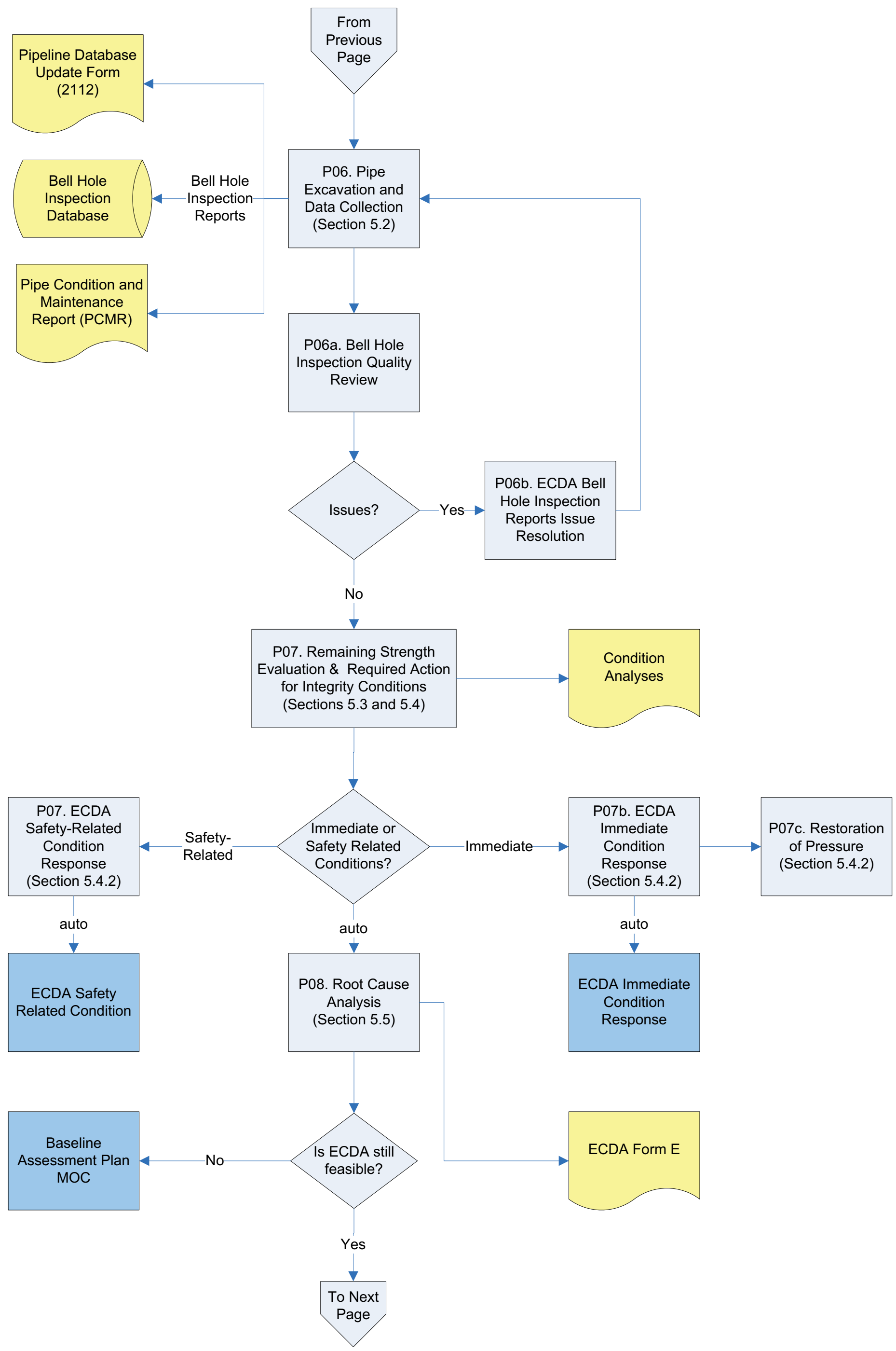
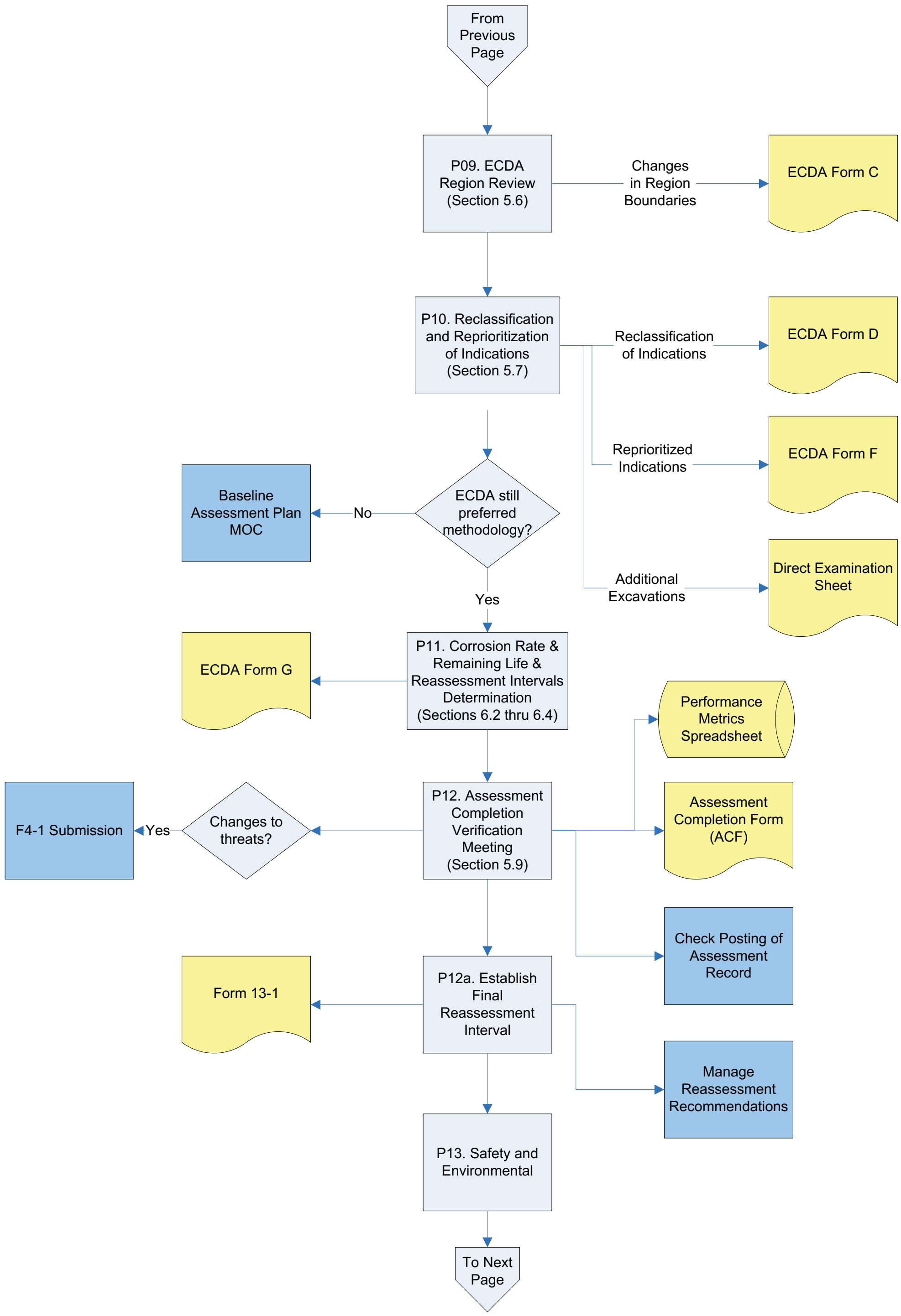


Figure 1, continued



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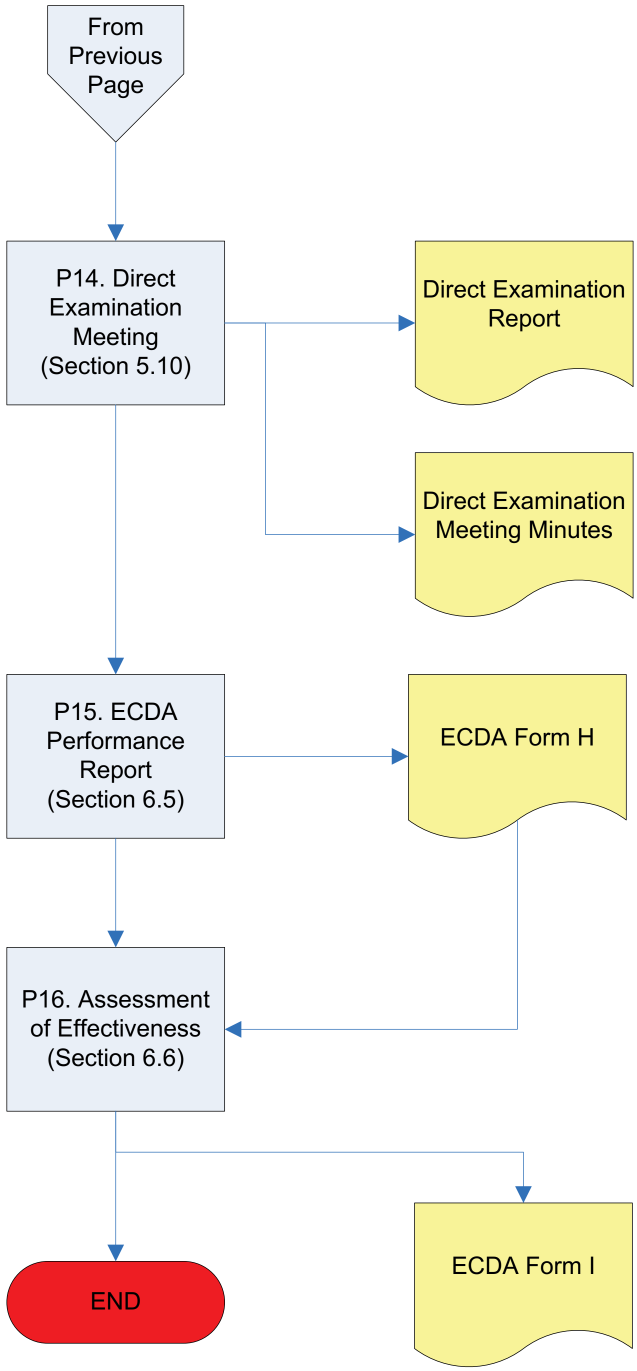

Figure 1, continued

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Added Form I to the ECDA ICAM process in Figure 1 (page 86) as recommended by the CPUC during the 2016 TIMP audit.

Document Profile Summary	
Responsible Person:	Zuniga, Gerardo - Gas Eng
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Part of Non-O&M Parts 191-193 Plan	Yes
Non-O&M 49 CFR Codes & Impacted Sections of Document	192.917(b): 3.3 192.923: Entire Doc 192.925: (b)(b2)(b3)(b4)-Entire Doc 192.933(b): 2.7, 5.3.2 192.933(c): 4.9 192.937: (c)2.3, 2.4
Part of Distribution IMP (DIMP)	No
Part of Transmission IMP (TIMP)	Yes
Impacts GO112E	No
GO112E Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document if Filed:	TIMP2
NOP Learning Module (LM) Training Code:	NOP00185

Company Operations Standard
Gas Standard
Pipeline Integrity

In-Line Inspection Procedure	SCG:	167.0210

VERSION 2.5

Table of Contents

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1.0 PURPOSE

The purpose of this Standard is to provide instructions on performing In-Line Inspection (ILI) surveys. This standard outlines the activities required to successfully plan, organize and execute an ILI survey. Guidelines pertaining to ILI data management and analysis are included.

2.0 INTRODUCTION

ILI is a non-destructive method of assessing the condition of the pipeline without disrupting the operation of the line. The most commonly used inspection tools are those associated with magnetic flux leakage (MFL) and ultrasonic testing (UT) technology.

2.1 ILI Process Phases

The ILI process is comprised of five assessment phases: Pre-Assessment, Inspection, Data Analysis & Reporting Requirements, Direct Examination (includes bellhole Inspection activities) and Post-Assessment. These phases will be described in greater detail later in this standard. ILI is one of several integrity assessment methods used by the Company to survey a pipeline. Other methods include External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA) and pressure testing using water, natural gas, air or an inert gas as the test medium.

3.0 CODE REFERENCES AND STANDARDS

Guidance from the federal codes and industry standards identified below are considered in this gas standard. The cross-reference table in **Appendix A** compares this standard with each applicable section of the referenced codes and standards. The protocol reference table in **Appendix B** compares this standard with each applicable PHMSA Inspection Protocol.

3.1 Federal Codes

3.1.1 49 CFR Part 192: Transportation of Natural and Other Gas by Pipeline

3.1.2 PHMSA Gas Transmission Integrity Management: Inspection Protocols

3.2 Industry Codes

3.2.1 ASME B31.8S: Managing System Integrity of Gas Pipelines

3.3 Recommended Standards

3.3.1 API 1163: In-Line Inspection Systems Qualification Standard

3.3.2 ASNT ILI-PQ: ILI Personnel Qualification and Certification Standard

3.3.3 NACE 05164: Assessment of ILI Tool Performance

3.3.4 NACE SP0102: Standard Practice for In-Line Inspection of Pipelines

3.3.5 NACE 35100: In-Line Nondestructive Inspection of Pipelines

4.0 POLICY AND SCOPE

4.1 Policy

This Standard shall be controlled and reviewed per the guidelines established under the Quality Assurance Plan (QAP) and Management of Change Process (MOC) established under the Pipeline Integrity Management Program.

4.2 Scope

This procedure is applicable for all transmission pipelines that are capable of being in-line inspected (i.e. piggable). These lines are located in the Distribution, Storage and Transmission departments. This procedure is compliant with pipeline integrity management requirements. The ILI tool selected shall be capable of detecting the threat(s) to which the pipe segment(s) is susceptible, otherwise, a different integrity assessment method shall be selected to evaluate the pipeline.

TIMP requirements related to compliance with 49 CFR Subpart O (e.g. reporting timeframes, condition responses, and notifications) may not apply for non-integrity related inspections, including but not limited to non-HCA areas, O&M specific inspections, research and development related activities, etc.

5.0 RESPONSIBILITIES AND QUALIFICATIONS

5.1 Roles and Responsibilities

5.1.1 Pipeline Integrity Assessment Manager

The Assessment Manager (AM) has the overall responsibility of ensuring this procedure is implemented in accordance with Code requirements and applicable sections of the recommended standards. All program-related changes shall be overseen by the AM. Any deviation from this standard shall require approval from the AM and be documented using the exception process (**Form A**). The AM may delegate approving responsibilities to other members of the ILI team.

5.1.2 Pipeline Integrity Engineering Project Manager

The Engineering Project Manager (EPM) shall be responsible for assigning ILI projects to the Pipeline Integrity Engineers. The EPM shall ensure the ILI projects are conducted in accordance with this procedure and shall plan and communicate the status of ILI projects to all stakeholders. This procedure contains several time-sensitive tasks and the EPM shall have the responsibility of ensuring those deadlines are met. In addition, the EPM shall provide coordination between Field Operations/Transmission Pipeline Integrity and the Pipeline Integrity Engineer.

5.1.3 Pipeline Integrity Engineer

The Integrity Engineer (IE) shall be the technical point of contact and be responsible for the analytical activities associated with the ILI process, which include but are not limited to: selection of an appropriate integrity assessment, ILI data analysis and integration and remaining strength evaluations of corroded pipelines. This procedure contains several time-critical tasks for which the IE shall be responsible for meeting. The IE shall immediately notify the EPM if a deadline cannot be met.

5.1.4 Pipeline Integrity Transmission Planning Project Manager

The Planning Project Manager (PPM) is responsible for overseeing the field activities associated with the ILI process. The PPM shall be responsible for scheduling the ILI project and obtaining all necessary permits. The PPM shall identify any mechanical features on a pipeline that would obstruct the passage of ILI tools. Other responsibilities include but are not limited to: field-verifying high consequence areas, material requisitions, allocating resources, pipeline retrofits, identifying flow and pressure conditions, and assigning & managing personnel during any construction-related activities. The PPM shall serve as the liaison between Pipeline Integrity and several Gas Company departments including District Regions, Gas Control, Public Affairs and Environmental Services.

5.1.5 Inspection Personnel

Inspection Personnel (IP) shall be responsible for conducting direct examination of pipelines. The IP shall have appropriate certifications and possess the necessary equipment to perform the pipeline inspections.

5.2 Qualifications

The provisions of this procedure shall be implemented under the direction of competent persons who, by reason of knowledge of the physical sciences, mathematics or the principles of engineering, acquired by education and/or related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on natural gas piping systems.

5.2.1 Minimum Qualifications

Table 1 lists the minimum qualifications required among approves for each step of this process in accordance with **Manual TIMP.15**.

Table 1: TIMP Minimum Qualifications

Requirements	AM	EPM	IE	IP
ILI Procedure Training	X	X	X	
NACE CP1 certification or a minimum of 5 years of relevant technical experience	X	X	X	
RSTRENG/KAPA Training			X	
ASNT Level 1 UT & MPI				X

6.0 DEFINITIONS

Terms and definitions are provided in **Manual TIMP.A**. Only terms not included in TIMP.A are provided below. Not all terms are used within this Standard.

Above-Ground Marker (AGM): A portable or permanently installed device placed on the ground above a pipeline that both detects and records the passage of an in-line inspection tool or transmits a signal that is detected and recorded by the tool.

Actionable Anomaly: Anomalies for which sufficient information exists to take appropriate action. Refer to **Figure 1** for an overview of the inspection terminology hierarchy.

B-Scan: A cross-sectional display of a test object formed by plotting the beam path lengths for echoes with a preset range of amplitude, in relation to the position of beam axis (in ultrasonic testing), or the values of the measured magnetic field (with magnetic flux leakage), as the probe is scanned in one direction only.

Bend: A physical configuration that changes pipeline direction. A bend can be classified according to the centerline radius of the bend as a ratio to the nominal pipe diameter. A 1 ½ D bend would have a centerline radius of 1 ½ times the nominal pipe diameter. A 3 D bend would have a centerline radius of three times the nominal pipe diameter.

Buckle: A condition in which the pipeline has undergone sufficient plastic deformation to cause permanent wrinkling or deformation of the pipe wall or the pipe's cross section.

C-Scan: A two-dimensional plane display of a test object formed by plotting the presence of echoes with a preset range of amplitude, a beam path length (in ultrasonic testing), or the values of the measured magnetic fields (with magnetic flux leakage), in relation to the position of the scanning probe.

Caliper/Deformation/Geometry Tool: An in-line inspection tool designed to record conditions, such as dents, wrinkles, ovality, bend radius and angle by sensing the shape of the internal surface of the pipe.

Chainage: Cumulative pipeline distance usually measured on the surface from a specific point of origin.

Check Valve: Valve that prevents reverse flow. This type of valve can cause damage to ILI tools if not fully opened.

Class Location: A criterion for pipeline design set by the Code of Federal Regulations, Title 49, Part 192. Class 1 is rural and Class 4 is heavily populated. Protocols for determining a class location are provided in **Standard 182.0190**.

Cleaning Tool: A utility pig that uses cups, discs, scrapers or brushes to remove dirt, rust, mill scale, corrosion products, and other debris from the pipeline. Cleaning pigs are utilized to increase the operating efficiency of a pipeline or to facilitate inspection of the pipeline.

Coating Disbondment: The loss of adhesion between a coating and the substrate.

Combination Tool: An instrumented in-line inspection tool designed to perform both geometry (deformation or caliper) inspections as well as metal loss inspections with a single tool chassis.

Component: Any physical part of the pipeline, other than line pipe, including but not limited to valves, welds, tees, flanges, fittings, taps, branch connections, outlets, supports, and anchors.

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

Crack or Cracking: A fracture type of discontinuity characterized by a sharp tip and high ratio of length to width to opening displacement.

Deformation: A permanent change in shape, such as a bend, buckle, dent, ovality, ripple, wrinkle, or any other change that affects the roundness of the pipe's cross-section or straightness of the pipe.

Dent: A local change in piping surface contour caused by an external force such as mechanical impact or rock impact.

Detect: To sense or obtain a measurable indication from a feature.

Detection Threshold: A characteristic dimension or dimensions of an anomaly that must be exceeded to achieve a state probability of detection.

Differential Pressure: The difference between the pressures behind and ahead of the in-line inspection tool- the actual propeller of the tool.

Dummy Tool Run: Preliminary run of an un-instrumented pig to verify safe passage of a fully instrumented tool through a section of pipeline. Dummy runs can also be used to remove debris from the inside of the pipeline.

Electromagnetic Acoustic Transducer (EMAT): A type of transducer that generates ultrasound in steel pipe without a liquid couplant using magnets and coils for inspection of the pipe.

False Call: An inspection indication that is erroneously classified as an anomaly or a defect.

Fatigue: The process of progressive localized permanent structural change occurring in a material subjected to fluctuating stresses less than the ultimate tensile strength of the material that may culminate in cracks or complete fracture after a sufficient number of fluctuations.

Feature: Any physical object detected by an in-line inspection system. Features may be anomalies, components, nearby metallic objects, welds, appurtenances, or some other item. Refer to **Figure 1** for an overview of the inspection terminology hierarchy.

Flash Welded: Distinct type of electric resistance weld (ERW) pipe, made from individually rolled plates formed into cans before being welded.

Fracture Mechanics: A quantitative analysis for evaluating structural reliability in terms of applied stress, crack length, and specimen geometry.

Free Corrosion Potential: The electric potential that exists in the absence of an applied potential with corrosion occurring. This is also known as the native potential.

Gauge Tool: A utility pig mounted with a flexible metal plate of a specified diameter less than the minimum internal diameter of the pipeline. Pipe bore restrictions less than the plate diameter or short radius bends will permanently deflect the plate material.

Girth Weld: A complete circumferential butt weld joining pipe or components.

Gouge: Elongated grooves or cavities usually caused by mechanical removal of metal.

Hall-Effect Sensor: A type of sensor that directly measure magnetic field. Hall-effect sensors require power to operate.

Hard Spot: A localized increase in hardness through the thickness of a pipe, produced during hot rolling of a steel plate as a result of localized quenching.

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

Hoop Stress: Stress around the circumference of a pipe (i.e., perpendicular to the pipe length) caused by internal pressure.

Hydrostatic Test: A pressure test of a pipeline in which the pipeline is completely filled with water and pressurized to ensure it meets the design conditions and is free of leaks.

In-Line Inspection Report: A report provided to the Operator that contains a comprehensive analysis of the data from an in-line inspection.

In-Line Inspection Technology: A class of inspection methodologies (i.e., EMAT, MFL, Ultrasonic, etc.) used in the performance of an in-line inspection.

In-Line Inspection Tool: The device or vehicle that uses a nondestructive testing (NDT) technique to inspect the pipeline from the inside. An ILI tool is also known as an intelligent or smart pig.

Interaction Rules: A spacing criterion among anomalies that establishes when closely spaced anomalies should be treated as a single, larger anomaly.

Intergranular Crack: Crack growth or crack path that is between the grains of the metal.

Kicker Line: Piping and valving that connects the pressurizing pipeline to the launcher or receiver.

Lamination: An internal metal separation creating layers generally parallel to the surface.

Launcher: A pipeline device used to insert a pig into a pressurized pipeline.

Magnetic Flux Leakage (MFL): A type of in-line inspection technology in which a magnetic field is induced in the pipe wall between two poles of a magnet. Anomalies affect the distribution of the magnetic flux in the wall. The magnetic flux leakage pattern is used to detect and characterize anomalies.

Magnetic Particle Inspection (MPI): A nondestructive examination (NDE) technique for locating surface flaws in steel using fine magnetic particles and magnetic fields.

Magnetic Permeability: The ability of magnetic flux to diffuse through (or permeate) a magnetic material. It is the ratio of magnetic flux density to magnetic field strength.

Maximum Operating Pressure (MOP): The maximum internal pressure that cannot normally exceed the maximum allowable operating pressure expected during the operation of a pipeline.

Measurement Threshold: A characteristic, dimension or dimensions above which an anomaly measurement can be made.

Metal Loss: Any pipe anomaly in which metal has been removed. Metal loss is usually the result of corrosion, but gouging, manufacturing defects, or mechanical damaging can also cause metal loss.

Mill Related Anomalies: Anomalies in pipe or weld metal resulting from the manufacturing process.

Nominal Wall Thickness: The wall thickness specified for the manufacture of the pipe. Actual wall thickness will vary within a range permitted by the pipe manufacturing standard/specification and sometimes will vary outside the range if the manufacturing was not performed within the stated tolerance.

Nondestructive Testing Method: A particular method of NDT, such as radiography, ultrasonic, magnetic testing, liquid penetrant, visual, leak testing, eddy current and acoustic emission.

Nondestructive Testing Technique: A specific way of utilizing a particular NDT method that distinguishes it from other ways of applying the same NDT method. For example, magnetic testing is a NDT method, while magnetic flux leakage and magnetic particle inspection are NDT techniques. Similarly, ultrasonic is a NDT method, while contact shear-wave ultrasonic, and contact compression-wave ultrasonic are NDT techniques.

Ovality: Out of roundness, i.e., egg shaped or broadly elliptical.

pH: The negative logarithm of the hydrogen ion activity written as $pH = -\log_{10} (a_{H^+})$ where a_{H^+} = hydrogen ion activity = the molar concentration of hydrogen ions multiplied by the mean ion-activity coefficient.

Performance Specification: A written set of statements that define the capabilities of an in-line inspection system to detect, classify, characterize and/or measure anomalies and other features.

Pig Signal: This is usually a mechanical sensor on the pipe that is activated by the passage of a pig.

Pipeline Component: A feature or appurtenance such as a valve, cathodic protection connection, or tee that is a normal part of the pipeline. The component may produce an indication that is recorded as part of an inspection by an in-line inspection tool or configuration pig. See also *Component*.

Pipeline Coordinates: Location coordinates of the course that a pipeline follows as given in a standard geographic coordinate system.

Pipeline System: All portions of the physical facilities through which gas, oil, or product moves during transportation. This includes pipe, valves, and other appurtenances attached to the pipe, compressor units, pumping units, metering stations, regulator stations, delivery stations, tanks, holders, and other fabricated assemblies.

Pitting: Localized corrosion of a metal surface that is confined to small areas and takes the form of cavities called pits.

Pressure: Level of force per unit area exerted on the inside of a pipe or vessel.

Probability of Detection (POD): The probability of a feature being detected by an in-line inspection tool.

Probability of Exceedence (POE): The probability of a defect larger than critical size, given an anomaly of the size predicted by the ILI inspection tool.

Probability of False Call (POFC): The probability of a non-existing feature being reported as a feature.

Probability of Identification (POI): The probability that an anomaly or other feature, once detected, will be correctly identified.

Pup Joint: A short piece of pipe, typically 3 m (10 ft) or less in length.

Receiver: A pipeline facility used for removing a pig from a pressurized pipeline. It may be referred to as trap, pig trap, or scraper trap.

Reference Point: A well-documented point on the pipe or right of way that serves as a measurement point for location of anomalies.

Remnant Magnetization: The magnetization level left in a steel pipe after the passage of a magnetic in-line inspection tool.

Reporting Threshold: A parameter that defines whether or not an anomaly will be reported. The parameter may be a limiting value on the depth, width, or length of the anomaly or feature.

Ripple: A smooth wrinkle or bulge visible on the outside wall of the pipe. The term Ripple is sometimes restricted to wrinkles or bulges that are no greater in height than 1.5X wall thickness.

Residual Stress: Stress present in an object in the absence of any external loading; results from manufacturing process, heat treatment, or mechanical working of material.

RSTRENG: Analysis criterion specified in the American Gas Association project report AGA-PR-3-805,19 "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe."

Rupture Pressure Ratio (RPR): The ratio of the "predicted burst pressure" also known as the "failure pressure" calculated by an analysis criterion (e.g., ASME B 31G, RSTRENG, etc.) to the pressure at specified minimum yield stress (SMYS).

Seam Weld: The longitudinal or spiral weld in pipe, which is made in the pipe mill.

Seamless: Pipe made without a seam weld.

Sensors: Devices that receive a response to a stimulus, (e.g., a MFL sensor detects flux leakage).

Shear Wave: Pertaining to pipe inspection, shear waves are generated in the pipe wall by transmitting ultrasonic pulses through a liquid medium. The same transducer is used for both sending and receiving ultrasound (so-called pulse echo technique). The angle of incidence is adjusted in such a way that a propagation angle of approximately 45° is obtained in the pipe wall. By using 45° shear waves, it is possible to detect radial-oriented, surface-breaking cracks at both sides of the pipe wall with high sensitivity, because the ultrasound pulse undergoes a strong angular reflection at the crack edge (so-called corner reflection).

Sizing Accuracy: The accuracy with which an anomaly dimension or characteristic is reported. Typically, accuracy is expressed by tolerance and a certainty. As an example, depth sizing accuracy for metal loss is commonly expressed as +/-10% of the wall thickness (the tolerance), 80% of the time (the certainty).

Sphere Pig: A spherical utility pig made of rubber or urethane. The sphere may be solid or hollow, filled with air or liquid. The most common use of sphere pigs is as a batching pig.

Spiral Weld: A longitudinal DSAW that traverses helically around the pipe. A welding process used in the manufacture of pipe.

Strain: Increase in length of a material expressed on a unit length basis (e.g., millimeters per millimeter or inches per inch).

Strain Hardening: An increase in hardness and strength caused by plastic deformation at a temperature below the re-crystallization range.

Stress: Tensile, shear or compressive force per unit area.

Tensile Stress: Stress that elongates the material.

Tolerance: The range with which an anomaly dimension or characteristic is sized or characterized.

Transducer: A device for converting energy from one form to another. For example, in ultrasonic testing, conversion of electrical pulses to acoustic waves, and vice versa.

Transgranular Crack: Crack growth or crack path that is through or across the grains of a metal.

Trap: A pipeline facility for launching or receiving tools and pigs. See Launcher and Receiver.

Utility Pig: A pig that performs relatively simple mechanical functions such as cleaning the pipeline.

Validation/Verification Dig: An excavation made to validate/verify the reported results of an in-line inspection.

Wrinkle: A smooth and localized bulge visible on the outside wall of the pipe. The term wrinkle is sometimes restricted to bulges that are greater in height than one wall thickness.

Yield Pressure: The pressure at which the nominal hoop stress in the pipe wall equals the specified minimum yield stress of the pipe grade.

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

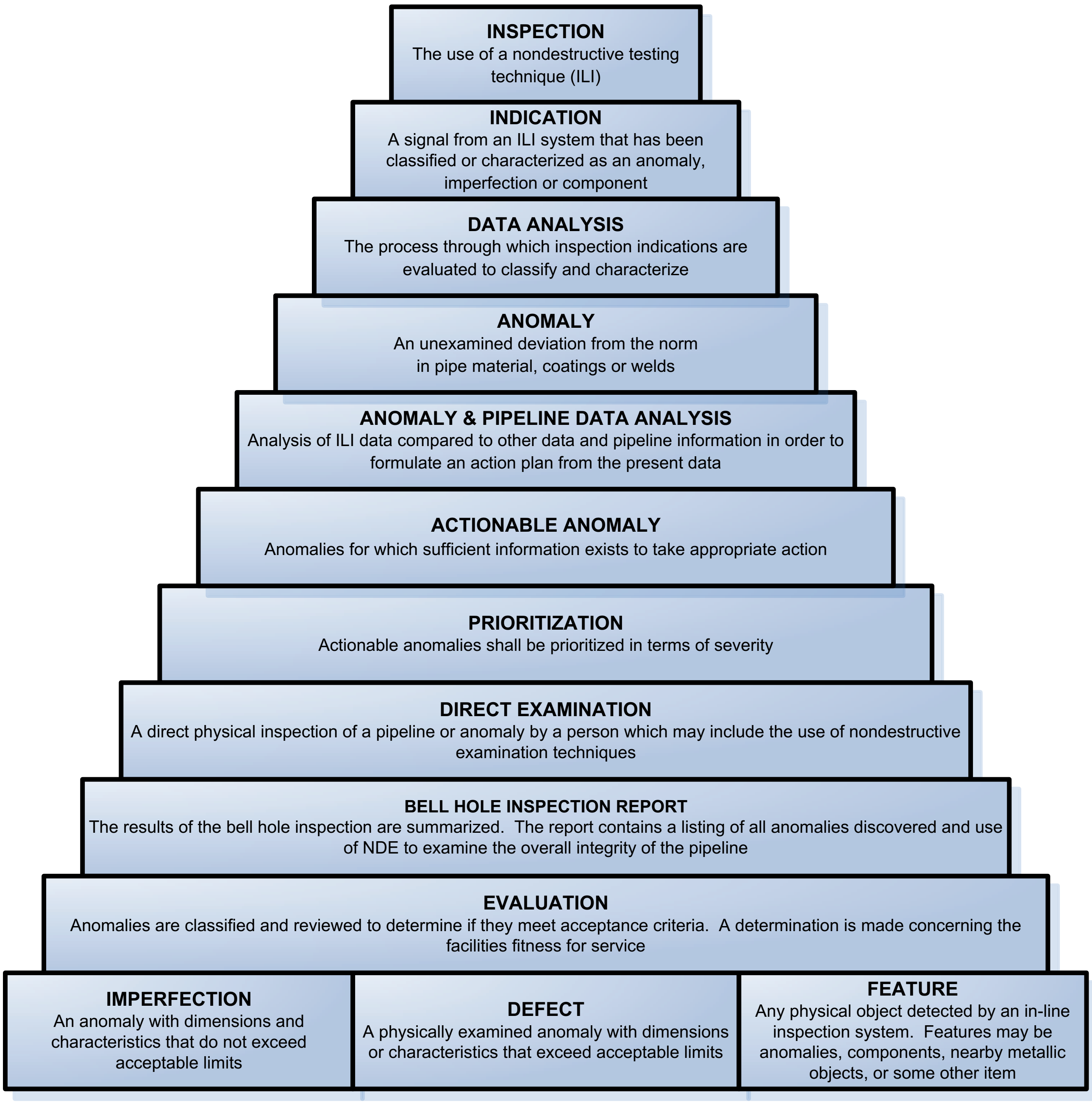


Figure 1: Inspection Terminology Hierarchy

7.0 PRE-ASSESSMENT

Pre-assessment is the first step in the assessment process. The step is characterized by extensive data collection, review, integration and analysis. Pre-assessment has the following main objectives:

- Identification of pipeline features that would obstruct the passage of the ILI tool such as back to back elbows with minimal separation between them, presence of ported valves, elbows or bends less than 1.5 D, etc.;
- Identification and verification of ASME B31.8S threats to each pipe segment (i.e., external corrosion, third party damage, construction, etc.);
- Review of previous assessments to identify successes or lessons learned;
- Review of previous direct examinations to substantiate the performance of the ILI tool used or the efficiency of the previous assessment;
- Selection of an appropriate ILI tool or other integrity assessment method based on existing threats to the pipeline and the feasibility of.

7.1 Scheduling and Planning the ILI Survey

The main objective of the planning phase is to determine if the pipeline is piggable. If the pipeline is not piggable, appropriate modifications may be made to facilitate inspection. Scheduling and planning an ILI survey is a function of the Gas Transmission Pipeline Integrity Planning group. The process is a coordinated effort with several Gas Company departments such as Public Affairs, Regional Districts, Gas Control and Environmental Services. Obtaining permits from outside agencies is often necessary anytime modifications are required on pipelines that run through environmentally or ecologically sensitive areas. The PPM shall be responsible for all activities associated with scheduling/planning an ILI survey including but not limited to the following:

7.1.1 Physical Pipeline Restrictions

Many mechanical features present a hazard for ILI tools by damaging or lodging the tools. Some of the most commonly found problematic installations are described below. Additional guidelines for preparing pipelines for an ILI survey are provided in **Standard 223.0410**.

7.1.1.1 *Short Radius Bends/Elbows:* Bends or elbows with short radii should be identified since many ILI tools may not be able to negotiate them. The typical minimum radius for elbows and pipe bends in pipelines intended for pigging is provided in **Table 2**. A schematic is included in **Figure 2**.

Table 2: Minimum Elbow/Bend Radius

Nominal Pipe Size	Minimum Bend Radius
4-inch	10 x nominal pipe size
6-inch to 14-inch	3 x nominal pipe size
16-inch and larger	1.5 x nominal pipe size

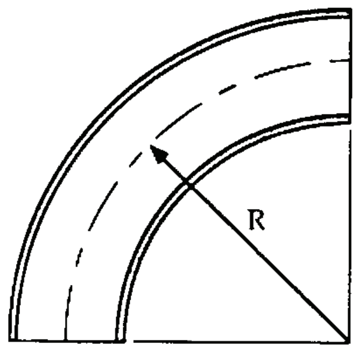


Figure 2: Elbow/Bend Radius Schematic

7.1.1.2 *Back-to-Back Bends:* Bends that are installed in a back-to-back configuration without an intervening section of straight pipe can present a lodging hazard for ILI tools.

7.1.1.3 *Miter Bends:* These types of bends are generally present in older lines located in areas susceptible to geotechnical movement and could have pipeline deformations that may not be identified until attempting the ILI run.

7.1.1.4 *Unbarred and Back-to-Back Branch/Tee Connections:* Branch/tee connections where the inside branch diameter to inside header (main line) diameter is greater than the ratios shown in **Table 3** should be fitted with guide bars. Back-to-back branch/tee connections should be evaluated on a case by case basis since a situation in which the ILI tool stalls can be created.

Table 3: Maximum Branch Ratios (d_i/D_i)

Branch Configuration	Maximum Unbarred (d_i/D_i) Ratio
Side/top Opening	0.60
Bottom Opening	0.50

7.1.1.5 *Reduced Port/Check Valves:* Reduced port or check valves (not full opening) can result in ILI tool damage, and in a worst-case scenario, they can cause the tool to become lodged in the line.

7.1.1.6 *Dual Diameter Pipelines*: Some ILI tools can only negotiate diameter changes of one line size (e.g., 22-inch to 24-inch).

7.1.1.7 *Internal Probes*: Probes intruding into the pipeline can restrict inspection tools. Failure to remove them can result in damage to the tools and pipeline facilities.

7.1.1.8 Installations such as mainline drips without orifice plates, chill rings and y-connections can present lodging hazards for ILI tools.

7.1.1.9 The PPM shall review as-built drawings, work orders, purchasing records and other Company documents to identify any of the aforementioned physical restrictions.

7.1.2 Launching and Receiving Facilities

Existing and proposed launching/receiving facilities must be reviewed for suitability because ILI tools vary in complexity, geometry and maneuverability. Consideration should be given to the following:

7.1.2.1 *Work Space Availability:* The work area should be reviewed to ensure sufficient space for maneuvering tools and associated equipment during loading and unloading operations.

7.1.2.2 *Site Accessibility:* Sites may be affected by length of daylight, wildlife corridors, weather and other environmental and safety concerns.

7.1.2.3 *Barrel/Trap Length:* The overbore section length on the launcher should be greater than or equal to the tool length. For receivers, the nominal pipe section length must be greater than or equal to the tool length to ensure the entire tool will clear the isolation valve. The length of the overbore section must be sufficient to accommodate the tool stopping distance upon receipt.

7.1.2.4 *Pipeline Spans:* Pipeline spans may require reinforcement to accommodate the weight of the ILI tool. Gas Engineering Pipeline Design should be contacted for support.

7.1.3 Operational Conditions

Operational issues such as insufficient flow or pressure, high gas temperatures and presence of chemical contaminants in the gas stream should be considered.

7.1.3.1 *Gas Flow Rate:* The gas flow rate is dependent on the operating pressure and diameter of the pipeline and should be sufficient to run an ILI tool.

7.1.3.2 *Gas Velocity:* The gas velocity is also a function of the operating pressure and diameter and should be sufficient to run the ILI tool.

7.1.3.3 *Pipeline Operating Pressure:* Most ILI tools require a minimum operating pressure of 400 psig to operate within vendor specifications. The effects of operating a tool on a pipeline with an operating pressure less than 400 psig should be considered.

7.1.3.4 *Gas Composition:* Contaminants such as hydrogen sulfide (H_2S) in the gas steam can limit the tools' abilities to operate effectively due to the corrosive effects of the compound.

7.1.4 Waste and Debris Collection

The PPM shall make plans for collecting wastes generated during ILI runs. Temporary tankage may be necessary for collected liquids, sludge, etc. Permits may be required for transporting these wastes to an offsite facility.

7.1.5 Field Verification of High Consequence Areas

The EPM shall provide the PPM high consequence area (HCA) maps for field verification. Any visual changes observed in the HCA boundaries shall be communicated to the IE.

7.2 Data Gathering and Integration

The IE shall be responsible for most activities associated with this section. Collection, review and integration of relevant data and information are necessary to understand the condition of the pipeline. All data collected shall be summarized in the Pre-Assessment and Feasibility Report (refer to §7.11).

There are many data sources within the Company that contain operational, maintenance and integrity related information such as Operations and Maintenance Orders, Pipe Condition and Maintenance Reports and Bellhole Inspection Reports. Guidelines for acquiring information are provided in **Standard 167.0200**.

The most commonly used data sources during the pre-assessment process are identified below. The IE shall review these sources to obtain important information on the pipeline:

- Construction Drawings
- Features Study
- Cathodic Protection Records

7.2.1 Construction Drawings

Construction drawings are provided by the PPM and contain the following information:

7.2.1.1 Line number, assessment name and pipeline trajectory.

7.2.1.2 Launcher/receiver details and associated piping plans including dimensions.

7.2.1.3 Filter/separator plans.

7.2.1.4 Any retrofits performed such as replacement of pipeline features or pipe sections.

7.2.1.5 The IE shall use information in the construction drawings to complete the vendor questionnaire.

7.2.2 Features Study

The EPM shall request a current line-specific Features Study from the Assessment Planning Team once an ILI survey is scheduled. Features Studies take several months to complete so sufficient notice should be provided to ensure these critical reports are readily available to the IE by the time the ILI survey is initiated. The EPM shall be responsible for checking and communicating the status of the Features Studies to the IE and all impacted stakeholders.

The Features Study is in Microsoft Excel format and provides a comprehensive listing of all features associated with a pipeline system including stationing, main line valves, tees, taps, electrical test stations, etc. In addition, operational and maintenance records along with cathodic protection information is provided. It is the most widely referenced source for data gathering during pre-assessment. The IE shall use the Features Study to obtain the basic information identified below and more critical information detailed in later sections of this Standard. This information will be included in the Pre-Assessment and Feasibility Report (refer to §7.11).

7.2.2.1 Diameter

7.2.2.2 Nominal wall thickness

7.2.2.3 Pipe grade

7.2.2.4 MAOP

7.2.2.5 Operating stress

7.2.2.6 Longitudinal seam type

7.2.2.7 Installation year(s)

7.2.2.8 Manufacturer

7.2.2.9 The limits of the ILI including start and end stationing

7.2.3 Historical Cathodic Protection Readings

Cathodic Protection (CP) can be defined as a technique that reduces the corrosion rate of a metal surface by making that surface the cathode in an electrochemical corrosion cell.

7.2.3.1 The Integrity Engineer shall request historical CP readings (also known as pipe to soil potentials) from the Preventive and Mitigative Measures (P&M) Group.

7.2.3.2 The IE shall collaborate with P&M to determine if the CP readings warrant additional integrity related digs (refer to §9.4).

7.2.4 Other Data Sources

There are many documents within the Company system that can be used to discover data that may not be available in the Features Study. Appendices A & B in **Standard 167.0200**, provide a comprehensive listing of additional sources, data descriptions and its location. These sources include but are not limited to the following:

7.2.4.1 Operating and Maintenance Order (OMO)

7.2.4.2 Pipe Condition and Maintenance Report (PCMR)

7.2.4.3 Transmission Leak Report (TLR)

7.2.4.4 Company **Form 2112**

7.2.4.5 Technical Evaluations

7.2.4.6 Region Reports of Safety-Related Pipeline Conditions

7.2.4.7 Survey Reports/Drawings

7.2.4.8 Emergency Response Plans

7.2.4.9 Manufacturer Equipment Data

7.3 High Consequence Area Identification

High consequence areas (HCAs) are characterized by densely populated locations, or areas where a pipeline is located within a specified distance from an "identified site" (e.g., facilities with persons who are mobility-impaired, confined, or hard to evacuate, such as hospitals, churches, schools, or prisons, and places where people gather for recreational purposes). Such distances are a function of the pipelines diameter and operating pressure. Additional details on the methodologies for establishing an HCA are provided in **Standard 192.02**.

7.3.1 HCA Maps

The EPM shall request HCA Maps from the HPPD – Compliance & Analysis Group within the Operations Technology Department. The maps shall be available to the IE by the time the ILI survey is initiated. The IE shall use the HCA maps to view details on each HCA segment along a pipeline system. The maps provide an aerial view of each HCA and include the following information:

7.3.1.1 HCA Segment Name;

7.3.1.2 The start and stop stationing of the HCA segment along with GPS coordinates;

7.3.1.3 Class locations; and

7.3.1.4 The PIR and PIC

7.4 Baseline and Reassessment Plan

The Baseline and Reassessment Plan (BAP/RAP) is a Company document that establishes the requirements for performing an initial integrity assessment on each covered (HCA) pipeline segment. The IE shall review the BAP, which contains the information outlined in §§7.4.1 through 7.4.3.

7.4.1 Pipeline Threats

Threats are classified into 9 categories as defined in ASME B31.8S and include the following:

7.4.1.1 **External Corrosion**: Metal loss on the exterior of the pipeline due to the presence of an electrochemical corrosion cell.

7.4.1.2 **Internal Corrosion**: Metal loss on the interior of the pipeline due to the presence of an electrochemical corrosion cell. The presence of chemical contaminants and accumulation of liquids in the gas stream increases the pipelines susceptibility to internal corrosion.

7.4.1.3 **Stress Corrosion Cracking**: A form of environmentally assisted cracking that is induced from the combined influence of a tensile stress and a corrosive environment on a susceptible microstructure.

7.4.1.4 **Manufacturing**: Examples include defective pipe and long seams such as pre-1970 ERW and flash welded seams that have a history of brittle failures. These types of flaws are introduced during the manufacturing process at the pipe mill.

7.4.1.5 **Construction**: Examples include wrinkle bends and defective girth welds such as those associated with an acetylene process. These flaws are introduced during field construction activities.

7.4.1.6 **Third Party Damage**: Damage inflicted on a pipeline as a result of excavation activities performed by Company or third party entities.

7.4.1.7 **Incorrect Operations**: An example of an incorrect operation is over-pressuring a pipeline to a level greater than the MAOP.

7.4.1.8 **Equipment Failure**: Gasket or O-ring failure within a flange is an example of an equipment failure.

7.4.1.9 **Weather Related and Outside Force**: Pipelines located within areas susceptible to landslides or other geotechnical movements are susceptible to this threat.

7.4.2 Integrity Assessment Methods

Approved assessment methods include ILI, pressure testing, ECDA, etc.

7.4.3 Assessment Schedule

A schedule for completing the integrity assessment of all covered pipeline segments including risk factors considered in establishing the schedule is established in accordance with **Standard 167.0208**.

7.5 Threat Identification

The IE shall be responsible for identifying and evaluating all potential threats to each covered pipeline segment in accordance with the guidelines outlined in **Standard 167.0203**. Data collected during pre-assessment shall be used to substantiate the threats identified in the BAP, which are grouped into the following categories:

7.5.1 Time Dependent Threats

These include external corrosion, internal corrosion and stress corrosion cracking.

7.5.2 Static or Stable Threats

Examples of these threats are construction and manufacturing.

7.5.3 Time Independent Threats

These include third party damage and weather-related and outside force.

7.5.4 Human Error

Examples of these threats include incorrect operations and equipment failures.

7.5.5 Interactive Threats

These threats are the interaction of two or more of the aforementioned threats that increase the probability of failure to a level that is greater than the individual threats acting alone on the pipeline system. For example, external corrosion affecting a low-frequency ERW seam is an example of an interactive threat. This condition can result in a type of corrosion referred to as grooving corrosion or selective seam corrosion, which can exhibit higher growth rates than external corrosion outside of the seam.

7.6 Risk Assessment

Data from the various Company sources is assembled to conduct a risk assessment of the pipeline system or segments. The risk assessment methodology is used to prioritize all covered segments for inclusion in the initial assessment schedule and scheduling of re-assessments on a prioritized basis.

Risk Assessment Software is used to facilitate risk assessment of the pipeline system that allows for a complete, accurate and objective assessment of risk. The risk assessment software will dynamically segment the pipeline and calculate a relative risk score on each covered segment of the pipeline system. These scores are then utilized to generate pipeline risk ranking and are reported to the Assessment Planning Team for inclusion into the BAP schedule. The Risk & Threat Team is responsible for performing risk ranking of pipe segments within the Company's system. Risk assessment guidelines are provided in **Standard 167.0204**.

7.6.1 Risk Frame Modeler Tool

The Risk Frame Modeler (RFM) tool provides a risk assessment model for each covered segment as prescribed by ASME B31.8S, *Managing System Integrity of Gas Pipelines*. Results of the RFM tool analysis are tabulated into a report that contains risk scores for every pipe segment within the Company's system.

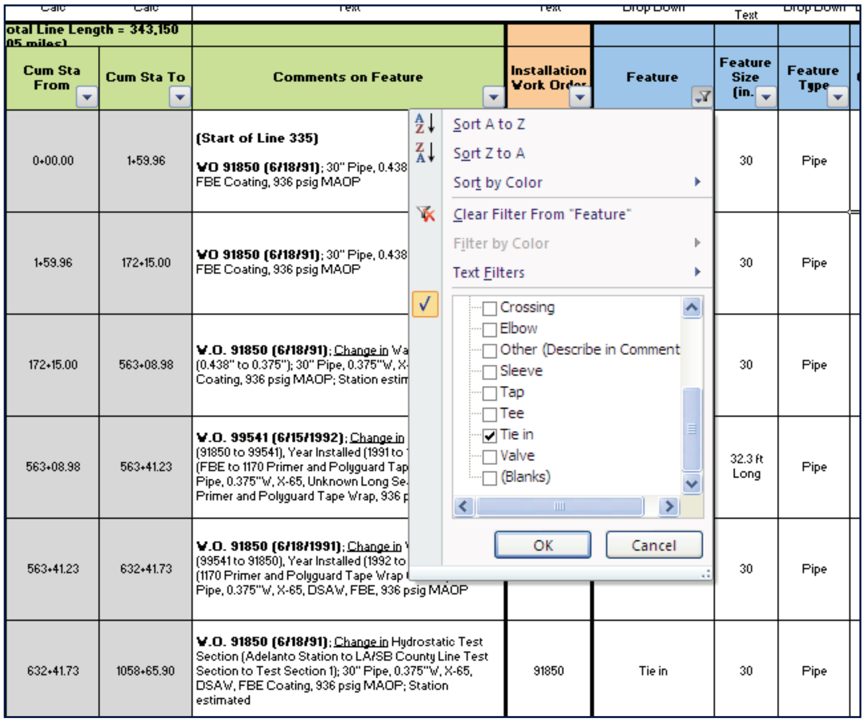
7.6.2 Risk Algorithm

The RFM tool uses the Risk Algorithm, a mathematical model consisting of formulas and input factors, which determines the likelihood of failure, consequence of failure, and risk score values for each pipeline segment.

7.6.3 Verifying the RFM Data

The IE shall verify the information in the RFM Report to ensure the threats remain valid. The data in the RFM Report shall be compared with data in the Features Study or another Company source to ensure correct pipeline attributes were used such as diameter, wall thickness, long seam type, coating type, manufacturing date, etc. Inputting incorrect data into the RFM risk tool could trigger false threats.

7.6.3.1 Filter the "Feature" column in the Features Study by "Tie-in" or the "Feature Type" column by "Pipe" to get the pipeline summary.



7.6.3.2 Compare the pipe segment data between the two document sources. When comparing the pipe segments use cumulative stationing since this type of stationing is used in the RFM report.

7.6.4 Threat Elimination or Addition

If any of the information in the RFM report is found to be inaccurate, which results in either the addition or removal of a pipeline threat, then Company **Form F4-1** shall be filled out to account for the new changes.

7.7 Short Segments

A short segment is a small portion of a covered pipe segment that cannot be inspected due to its configuration within the parent pipeline or the limitations of the inspection method. Short segments should be identified during the pre-assessment phase of assessment on each assigned pipeline, and categorized in accordance with §7.7.1 to allow for determination of the appropriate follow-on action (i.e. – CP readings, facility maintenance, etc.).

7.7.1 Short Segments Types

7.7.1.1 Associated Segments

Associated segments are characterized by the discontinuous nature of the inspection data (missing indirect inspection data is not in-line with the parent inspection method). These are commonly taps and crossover piping segments. Segments in this category are not inspected during the ILI survey, but assessment of the inspected line can be applied to the short segment provided that the short segment is of like size and kind to the surveyed pipe.

7.7.1.2 Inspection Gaps

Inspection data gaps are characterized by their continuity with the parent inspection data (missing data occurs in line with the parent inspection method). These are commonly pipe segments upstream/downstream of launcher/receivers (see Figure 3), etc.

7.7.2 Documentation

The IE shall identify associated segments and inspection gap extents using the Pre-Assessment & Feasibility Report (**Form C**).

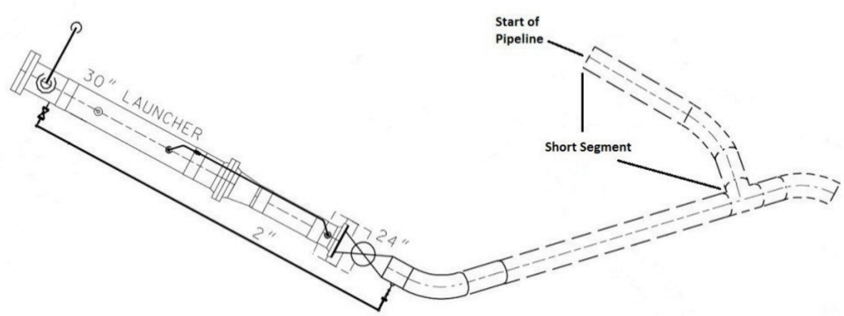


Figure 3: Sample Depiction of a Short Segment

7.8 Feasibility Analysis

The IE and PPM shall collaborate to determine if ILI is feasible. The PPM is responsible for performing the tasks outlined in §7.1. In addition, the IE shall review the Features Study and other data sources, if necessary, to identify the pipeline features in **Table 4**. These features can pose a hazard to the ILI tool and can lead to damage or in a worst case scenario cause the tool to become lodged. Additional guidelines are provided in **Standard 223.0410**.

Table 4: Physical Restrictions That Could Prevent ILI

	Physical Restriction	Concern
1.	Thread and Collar Couplings	Can cause damage to the sensors and other components in the ILI tool.
2.	Bell and Spigot Couplings	Can cause damage to the sensors and other components in the ILI tool.
3.	Chill Rings	Can cause damage to the sensors and other components in the ILI tool.
4.	Miter Bends	Typically these bends are less than 1.5 D making it difficult for the ILI tool to navigate through them.
5.	Elbows Less Than 1.5 D	Most ILI tools cannot navigate through elbows less than 1.5 D.
6.	Back-to-Back Elbows (>30 degrees)	Back-to-back bends without an intervening section of pipe can present an impediment or sticking hazard for ILI tools.
7.	Tee or Elbow Near MLV	This can be a lodging hazard due to front and back suction cups on ILI tool becoming lodged at the tee/elbow and MLV.
8.	Unbarred Tee or Branch Connections	Branch to header diameter ratios shall meet requirements in §7.1.1.4. The ILI tool can be lodged if the ratio requirements are not met.
9.	Back-to-Back Tee/Branch Connections	Lodging hazard for ILI tool if the branch to header diameter ratios are greater than the thresholds in §7.1.1.4.
10.	Y-Connections	Y-connections need to be barred since this poses a navigation and damage hazard to the ILI tool.
11.	Diameters > One Nominal Pipe Size	Most ILI tools can only negotiate one diameter pipe change (e.g., 24-inch to 26-inch).
12.	Wall Thickness > 0.625-inch	Heavy wall pipe can lead to speed excursions due to a greater pressure differential required to transition from a light to heavy wall pipe section
13.	Internal Probes	Navigation hazard which results in damage to ILI tools.
14.	Gate, Plug or Ported Valves	Navigation hazard which results in damage to ILI tools due to decreased diameter.
15.	Pressure Control Fittings	Some configurations can lead to sensor damage due to openings in pipe wall where fittings were installed.

	Physical Restriction	Concern
16.	Low Operating Pressure (<400 psig)	Could cause conditions where the tool is over-sped beyond vendor specifications due to pressure surges.
17.	Pipeline spans and supports	Pipeline spans/supports are not physical restrictions but may require reinforcement to accommodate the tool weight. The IE shall contact the Gas Engineering Pipeline Design team for support.

7.8.1 Previous ILI Surveys

The IE shall review the previous ILI survey to identify any tool problems or if any modifications to the pipeline system have occurred since the last inspection. The PPM will have information on the latter and should be contacted. The performance of the ILI tool shall be verified through previous bellhole inspection results.

7.9 ILI Tool Selection

ILI tools can be classified into four categories: Cleaning or Utility, Caliper/Geometry/Deformation, MFL and Ultrasonic. The IE shall analyze the goals and objectives of the inspection and select the appropriate ILI tool based on the anticipated pipeline anomalies. The IE shall adhere to the guidelines in ASME B31.8S, §6.2 when selecting an ILI tool. Any tool selected shall be capable of addressing the threat(s) identified on the pipe segment. The following paragraphs provide a summary of the various ILI tools available for assessing specific pipeline threats.

7.9.1 ILI Tools for Internal and External Corrosion Threats

The ILI tools listed below can be used to identify anomalies associated with these types of threats. The effectiveness of the tool is limited by its technology.

7.9.1.1 *Magnetic Flux Leakage, Standard Resolution*: This tool is suited for detection of metal loss but is limited by sizing accuracy due to the sensor size. This tool is not reliable for detection or sizing of axially oriented metal-loss defects.

7.9.1.2 *Magnetic Flux Leakage, High Resolution*: This tool provides better sizing capability than a standard resolution tool. Sizing accuracy is more applicable for geometrically simple defect shapes. Sizing accuracy degrades where pits are present or defect geometry becomes complex. It is not generally reliable for axially aligned metal-loss defects.

7.9.1.3 *Transverse Flux*: This tool is more sensitive to axially aligned defects than standard and high resolution MFL tools.

7.9.1.4 *Ultrasonic*: This tool usually requires a liquid couplant. Ultrasonic tools use sound waves of short wavelength and high frequency to detect flaws or measure pipe wall thickness. In addition to corrosion detection, these types of tools are useful for detecting cracks such as those associated with stress corrosion cracking.

7.9.2 ILI Tools for Stress Corrosion Cracking Threat

7.9.2.1 *Ultrasonic Tool*: See previous description.

7.9.2.2 *Transverse Flux*: This tool is able to detect some axially aligned cracks but not those associated with SCC.

7.9.2.3 *Electromagnetic Acoustic Transducer (EMAT)*: This EMAT tool consists of a coil in a magnetic field at the internal surface of the pipe wall. Alternating current placed through the coil induces a current in the pipe wall, causing forces on moving charges in the magnetic field, which in turn generate ultrasound.

7.9.3 ILI Tools for Third Party Damage and Mechanical Damage Threat

7.9.3.1 *Caliper, Geometry or Deformation*: These tools are most often used for detecting damage to the line involving deformation of the pipe cross section, which can be caused by construction damage, dents caused by the pipe settling onto rocks, third-party damage and wrinkles or buckles cause by compressive loading or uneven settlement of the pipeline.

7.9.4 ILI Tools for Weather-Related Outside Force Threat

7.9.4.1 *Inertial Mapping Unit*: ILI tools equipped with an inertial mapping unit (IMU) have appropriate built-in technology to detect this threat.

7.9.5 All Other Threats

ILI is not typically an appropriate assessment method for all remaining threats: manufacturing, construction, equipment and incorrect operations.

7.9.6 Inertial Mapping Unit

The intelligent tool shall be equipped with an IMU, which measures and records the location of the tool within the pipe. The positions of features such as welds, valves, and anomalous indications are determined by the ILI tool and the measurements from the IMU can then be referenced to the GPS reference datum. ILI runs equipped with IMU results in data containing GPS points for every pipeline feature including anomalies. These GPS coordinates are used to generate waypoints for the pipe anomalies that are then loaded onto a handheld GPS unit for locating.

7.9.7 Alternate Assessment Methods

Alternative assessment methods are summarized in Appendix A of **Standard 167.0208**. The IE shall use this table to identify alternate assessment methods if ILI is not feasible.

7.10 Pipeline Cleaning Requirements

If necessary, a cleaning program for the pipeline shall be designed and implemented. The specific tools for cleaning the pipeline shall be identified. The IE shall establish the cleaning requirements for the ILI survey. The following shall be considered in the decision process:

7.10.1 Historical data should be evaluated for anticipated contaminant deposits such as scale, dust, sludge, paraffin content, etc.

7.10.2 Lines that are on frequent maintenance programs may require less cleaning.

7.10.3 ILI vendors can provide additional guidelines for cleaning pipelines.

7.10.4 Cleaning requirements are discussed in greater detail in **Standard 167.0218**.

7.11 Pre-Assessment and Feasibility Report

The IE shall document the results of the pre-assessment process in the Pre-Assessment and Feasibility Report (**Form C**). This report is a detailed summary of the investigative effort performed by all personnel involved and shall contain a decision on whether or not ILI is feasible. If ILI is feasible, the IE shall identify the tool selected for the assessment.

7.11.1 Pre-Assessment and Feasibility Meeting

The objective of this meeting is to go over the results of the pre-assessment process and discuss the feasibility of performing ILI. The IE and PPM shall attend the meeting and discuss the topics outlined below. Meeting minutes shall be recorded by the IE using the Pre-Assessment and Feasibility Meeting Minutes template (**Form D**). Upon conclusion of the meeting, the IE shall disseminate the recorded minutes to all stakeholders involved in the ILI project.

7.11.1.1 Are the threats in the BAP still valid?

7.11.1.2 Are there any physical or operational restrictions on the pipeline that would prevent the successful passage of an ILI tool?

7.11.1.3 If the answer to the previous questions was yes, how will the pipeline be retrofitted to accommodate smart pigging?

7.11.1.4 Have other modifications been conducted on the pipeline since the previous ILI?

7.11.1.5 If applicable, were any problems encountered during the previous ILI run?

7.11.1.6 If problems were encountered, what necessary actions must be taken to avoid the issues that occurred during the previous survey?

7.11.1.7 What are the pipeline cleaning requirements?

7.11.1.8 What are the anticipated flow rate and operating pressure?

7.11.1.9 Are there any short segments?

7.11.1.10 Are there any customers that could be impacted by the ILI survey?

7.11.1.11 What are the required tools for the ILI survey?

7.11.1.12 Has the Data Management Team surveyed the line?

7.11.1.13 Have the HCAs been field verified?

7.11.1.14 If the feasibility analysis indicates that the ILI tool is not suited for the pipe inspection, then the tool selection process shall be revisited to address the specific operational limitations encountered. If ILI is still deemed not feasible then the IE shall select another integrity assessment method in accordance with **Standard 167.0208.**

7.11.1.15 Selection of an alternate integrity assessment method shall be performed in accordance with **Manual TIMP.14.**

7.12 Summary

The ILI Pre-Assessment process is summarized in **Figure 4**.

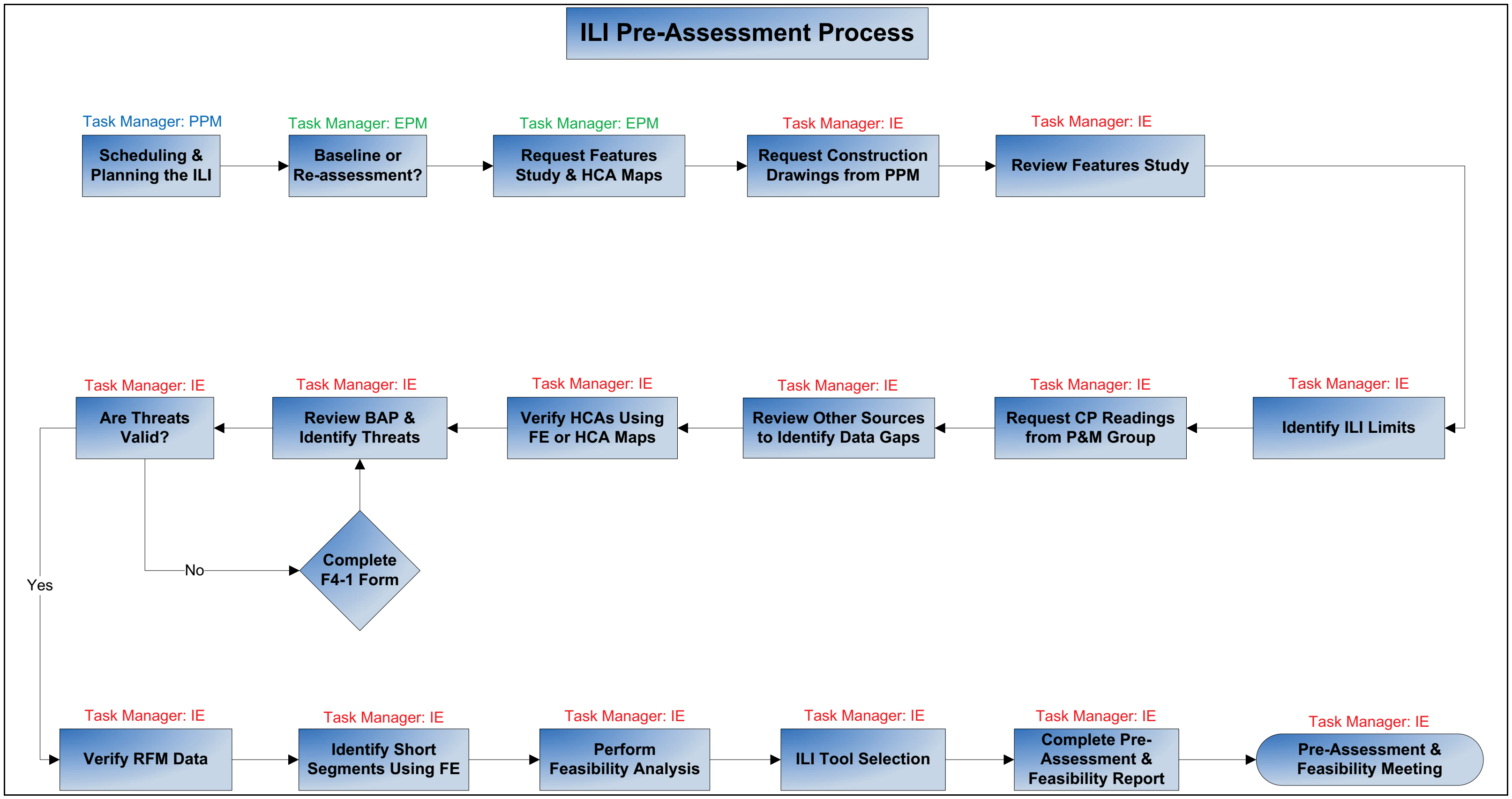


Figure 4: ILI Pre-Assessment Summary

8.0 IN-LINE INSPECTION

Conducting the pipeline inspection is the second phase in the ILI process. At this stage the assessment method has been selected and the request for proposal process to procure ILI services from vendors can commence. Tasks associated with this section include the following:

- Establishing minimum technical requirements for the ILI tool
- Procuring ILI services
- ILI tool compatibility assessment
- Completing the vendor questionnaire
- Benchmarking and Tracking
- Pre-Intelligent Tool Run Requirements
- Intelligent Tool Run Requirements
- Applying survey acceptance criteria

8.1 Minimum Technical Tool Requirements

Deformation and MFL tools shall meet or exceed the specification and accuracy requirements for feature detection and sizing shown in **Tables 5 and 6**. Exception or deviation from the requirements shown in Tables 5 and 6 must be made in writing to the AM.

8.2 Procurement of ILI Services

The PPM and EPM are responsible for procuring ILI services from vendors using the request for proposal (RFP) process. The roles of the vendor and Company shall be defined for all aspects of the ILI survey from implementation to delivery of the final report. Factors such as the implications of re-runs, scheduling changes, service interruptions and liability issues shall be addressed. The EPM shall furnish the vendor with pipeline data collected by the IE during the pre-assessment process. Specific vendor and Company requirements on ILI survey deliverables are detailed in **Standard 167.0220**.

8.2.1 Bending Strain Analysis

This type of analysis provides detailed pipeline data such as maximum depth, severity ratio (i.e. height/length) and bending strain calculated from the bend profile extracted from the ILI data. The data is used to perform strain monitoring, which is the process of comparing strains and curvature observed year to year when geotechnical or external forces may have significantly shifted within the inspection interval, causing unacceptable loading on the pipeline. The EPM shall be responsible for collaborating with Company experts to determine what pipelines require a bend strain analysis. The EPM shall take this reporting requirement into consideration during the RFP process since only certain ILI vendors can produce such analyses.

Table 5: Minimum Deformation Tool Specifications

Requirement	Specification
Bore restriction for tool navigation	10% of the OD and 1.5 D elbow/bend
Type of tool sensors/signals	Caliper, odometer, AGM, orientation and weld
Caliper sensor acquisition or sampling rate	1 sample/0.12-in
Feature orientation (clock position) resolution ≤	± 10°
Dent/ovality detection	2% of OD
Wrinkle detection (inward/outward)	1% of OD
Dent and ovality depth sizing accuracy	± 0.1-inch
Location accuracy	± 0.5%
Bend detection	22.5°

Feature	Probability of Identification > 90%
Internal Diameter Change	✓
Dent	✓
Wrinkle or buckle	✓
Ovality	✓
Bend	✓
Girth Weld	✓
Fitting	✓
Valve	✓
Tee	✓
Weld misalignment	✓

Table 6: Minimum MFL Tool Specifications

Requirement	Specification

Bore restriction for tool navigation	10% of the OD and 1.5 D elbow/bend
Type of tool sensors/signals	Axial, circumferential, radial (tri-axial models) and internal/external discrimination
MFL sensor acquisition or sampling rate	1 sample/0.08-in
Metal loss orientation (clock position) resolution	± 10°

Performance [Confidence Level (%)]	General	Pitting	Axial Grooving	Circ. Grooving	Axial Slotting	Circ. Slotting
Depth Detection [90%]	10% wt	12% wt	20% wt	12% wt	20% wt	15% wt
Depth Accuracy [80%]	± 10% wt	± 15% wt	± 20% wt	± 15% wt	± 20% wt	± 15% wt
Width Accuracy [80%]	± 0.75 in.	± 0.75 in.	± 0.75 in.	± 0.75 in.	± 0.47 in.	± 0.75 in.
Length Accuracy [80%]	± 0.75 in.	± 0.47 in.	± 0.75 in.	± 0.47 in.	± 0.75 in.	± 0.47 in.

Table 6: Minimum MFL Tool Specifications (Continued)

Feature	Probability of Identification (POI) > 90%	50% ≤ POI ≤ 90%	POI < 50%
Internal/external discrimination	✓		
Dent		✓	
Dent with metal loss		✓	
Ovality		✓	✓
Wall thickness change	✓		
Buckle > 0.25 in.	✓		
Weld Grinding		✓	
Gouge		✓	
Metal loss corrosion defect	✓		
Girth Weld	✓		
Longitudinal Weld	✓		
Bends: short and long radius	✓		
Wrinkles > 0.25 in.	✓		
Repair sleeves	✓		
Fittings (valves, tees, etc.)	✓		
Weld repair		✓	

8.3 ILI Tool Compatibility Assessment

Once the ILI vendor has been selected, the IE shall perform the following tasks: (a) provide pipeline data to the vendor using the vendor's pre-run questionnaire; and (b) request technical specifications from the vendor to perform a final tool compatibility assessment. The assessment is a cross-check to ensure that the selected ILI tool is compatible with the pipeline's operational and physical conditions.

8.3.1 Vendor Questionnaire

The IE shall request the questionnaire from the ILI vendor. The completed questionnaire shall be returned to the vendor along with the Feature's Study and survey control points. The questionnaire is intended to provide the vendor with all relevant parameters and characteristics on the pipeline to be inspected. Information in the questionnaire shall identify, but is not limited, to the following:

8.3.1.1 The presence of corrosive contaminants, such as H_2S, that could impact the tools' abilities to operate effectively;

8.3.1.2 Anticipated product velocity, flow rate, operating pressure and temperature ranges;

8.3.1.3 Presence of any physical pipeline restrictions that could not be retrofitted during the Planning stage;

8.3.1.4 Detailed information on launching/receiving facilities and associated piping including dimensions;

8.3.1.5 Requirements for defect assessment such as interaction rules and pressure based analyses and calculations (RSTRENG);

8.3.1.6 The physical location of where ILI tools and associated equipment are to be stored;

8.3.1.7 Contact information for all Company personnel involved in the ILI survey;

8.3.1.8 A listing providing survey control points and aboveground marker locations shall be supplied with the questionnaire (Refer to §8.4). A complete survey control point report may not be available until a few days prior to the ILI run.

8.3.2 ILI Tool Technical Specifications

The IE shall request an ILI tool specification from the vendor. The specification shall define the capabilities of the ILI tool to detect, locate, identify, characterize and measure anomalies and characteristics and identify the pipeline physical and operational requirements. The IE shall review the technical specification and conduct a final compatibility assessment prior to launch to ensure the tool will successfully navigate through the pipeline. The IE shall verify the following:

8.3.2.1 The pipeline wall thickness falls within the vendor specified range;

8.3.2.2 The anticipated pipeline flow rate, velocity and operating pressure fall within the vendor specified ranges and shall be sufficient to propel the ILI tool;

8.3.2.3 The tool shall negotiate through any physical restriction identified in **Table 4** that was not removed from the pipeline;

8.3.2.4 The launcher/receiver designs, specifically the traps, are of sufficient length to accommodate the ILI tool;

8.3.2.5 The battery life on the tool is sufficient to last the entire pipeline run;

8.3.2.6 If applicable, pipeline spans and mechanical pipe supports have been reinforced to ensure the weight of the ILI tool can be supported during passage.

8.4 Benchmarking and Tracking

The Data Management Group (DMG) within the Pipeline Integrity Department shall be responsible for establishing guidelines for survey control point (SCP), aboveground marker (AGM) placement and tracking requirements. The purpose of benchmarking is to correct for measured distance inaccuracies caused by ILI tool odometer wheel slippage and changes in elevation along the pipeline route. Benchmarking provides reference points for tracking the progress of the ILI tool along the pipeline, which provides the ability to control the speed of the ILI tool to ensure it remains within vendor specifications. The EPM shall provide the DMG sufficient notice to begin the survey since, depending on the length of the pipeline, surveys can be very time consuming.

8.4.1 Survey Control Points and Aboveground Marker Placement

SCPs are locations along a pipeline route used for placing reference aboveground markers to track the passage of the ILI tool. Markers can either be permanently attached to the pipeline (e.g., valves or electrical test stations) or portable aboveground marker (AGM) systems. SCP and AGM placement shall adhere to the requirements established in **Standard 167.0246**.

8.4.1.1 The Pipeline Integrity Planning and Construction teams and DMG shall collaborate to determine AGM placement.

8.4.1.2 At the conclusion of the survey the DMG shall provide the IE with an SCP and AGM listing. The IE shall forward the listing to the vendor for subsequent spatial alignment check.

8.4.2 ILI Tool Tracking

The Pipeline Integrity Planning and Construction teams shall be responsible for allocating and overseeing tracking personnel. Each tracking crew typically consists of the following:

8.4.2.1 An adequate number of individuals trained in the use of pig tracking equipment, tracking calculations, etc.;

8.4.2.2 An adequate number of vehicles suitable for the right-of-way being traveled;

8.4.2.3 Equipment capable of facilitating real-time communications at any time during the tracking activities;

Tracking personnel shall monitor the passage of the ILI tool at various pre-determined locations along the pipeline including AGM points. The Construction Manager shall be updated with the following tracking milestones during the run:

8.4.2.4 When the tool is ready to launch;

8.4.2.5 When the tool has been launched and tracking is underway;

8.4.2.6 Anytime irregularities are noted in the flow or pig travel;

8.4.2.7 At regular intervals to confirm the pig position and that the tracking personnel are not incapacitated;

8.4.2.8 When the pig has been received.

8.4.3 ILI Tool Transmitters

All ILI tools shall be equipped with transmitters to track their location along the pipeline. The transmitters also provide a means of detecting an ILI tool should it become lodged in the pipeline. The device shall be well-secured and not affect the bend-passing capability of the tool.

8.5 Pre-Intelligent Tool Run Requirements

8.5.1 Pre-ILI Meeting

A pre-ILI meeting shall be held between the ILI vendor, members of the Pipeline Integrity Planning and Construction groups, Gas Control, Distribution Regions, M&R, Marketing, Public Affairs and Pipeline Integrity Engineering to review the aspects of the ILI survey. The IE shall maintain a record of the meeting using the Pre-ILI Meeting Minutes form (**Form E**). The following items at a minimum shall be discussed during the meeting:

8.5.1.1 Pigging Procedure: This procedure provides a detailed description on launching and receiving instructions of ILI tools, valve operations, lockout and tag out procedures, contingency planning, ILI schedule, anticipated flow conditions, personnel responsibilities, etc.;

8.5.1.2 Cleaning requirements;

8.5.1.3 Manpower and equipment resources;

8.5.1.4 Expected pipeline operational conditions;

8.5.1.5 Previous inspection results, if applicable;

8.5.1.6 Is the ILI tool equipped with a speed control device?

8.5.1.7 ILI data analysis;

8.5.1.8 ILI schedule including start and end dates/times;

8.5.1.9 Land and access issues;

8.5.1.10 Company and vendor personnel involved in the pigging operation and points of contact;

8.5.1.11 Tracking requirements;

8.5.1.12 Environmental concerns;

8.5.1.13 Right of way restrictions (e.g., lines running through tortoise habitat require escorting by a biologist);

8.5.1.14 Engineering concerns such as over-speeding the tool and the effect on the data quality;

8.5.1.15 Storage accommodations for the ILI tools shall be identified.

8.5.2 Pipeline Cleaning Run

The pipeline shall be cleaned in accordance with §7.10, which refers to requirements established in **Standard 167.0218**.

8.5.2.1 Pipeline Integrity Environmental Services shall ensure that appropriate processes are in place to contain all debris or waste associated with the removal of the cleaning tools.

8.5.2.2 Samples of the waste shall be submitted to the Engineering Analysis Center via a chain of custody form for further analysis.

8.5.3 Pipeline Geometry Evaluation

The pipeline geometry shall be evaluated using a gauge/plate or deformation tool prior to running the "smart" pig. This is especially important for lines subject to high risk of third-party damage, high geotechnical risk and for lines undergoing baseline assessments where previous geometrical surveys are not available.

8.5.3.1 The gauge or plate tool will identify bore restrictions that would prevent the passage of the "smart" pig. The deflection on the plates will provide some details on the degree of the restriction.

8.5.3.2 A caliper/deformation tool will provide specific details on any bore restrictions in the pipeline since it is equipped with sensors. The tool will also evaluate bend radii to ensure the passage of the less flexible and more expensive "smart" pig.

8.5.3.3 If pipeline bend and bore information is current and reliable and deformation assessment is not necessary, a gauge/plate tool may be the only tool required.

8.5.3.4 Tracking should be used during the caliper/deformation inspection.

8.6 Intelligent Tool Run

8.6.1 General Preparation

8.6.1.1 Safety equipment such as fire extinguishers, gas detection meters, absorbent pads, silencers for blowing down the trap, environmental kits, tooling, etc. shall be available at the launching and receiving sites.

8.6.1.2 Safe operational procedures are used for the opening/venting of launchers and receivers.

8.6.1.3 Exact timing of the ILI tool shall be coordinated with the operations control center.

8.6.1.4 The proper size tools and equipment to load and extract the ILI tool shall be available on site.

8.6.1.5 If applicable, all pig indicators at the launching/receiving facilities shall be reset and be ready to identify the passage of the ILI tool.

8.6.2 Pre-Calibration Functionality Test

The ILI vendor shall functionally test and calibrate the intelligent tool prior to launch including checks of all onboard computer hardware and software. The ILI vendor shall confirm proper tool operation in writing. The report shall contain a checklist of all function tests performed. Depending on the vendor this report may be entitled "Quality

Control Checklist." Some pre-inspection function tests may include, but are not limited to:

8.6.2.1 Confirmation that an adequate power supply is available and operational;

8.6.2.2 Confirmation that all sensors, data storage, odometers and other mechanical systems are operating properly;

8.6.2.3 Confirmation that adequate data storage is available; and

8.6.2.4 Confirmation that all components of the inspection tool are properly initialized.

8.6.3 Mechanical Checks

Prior to the inspection run, the ILI tool shall be visually checked to ensure that it is mechanically sound. The electronics shall be checked to make sure they are properly sealed and functional.

8.6.4 Launching and Receiving Procedures

The requirements for launching and receiving ILI tools shall adhere to existing Company protocols. All system handling, placement, launching and receiving activities shall be carefully monitored to ensure safety of all personnel involved.

8.7 Post Intelligent Tool Run Requirements

8.7.1 Post-Calibration Functionality Test

The ILI vendor shall perform a post-calibration test to validate the tool functioned correctly and acquired all necessary data. The ILI vendor shall confirm the proper operation of the tool in the same manner as the pre-calibration test. The report shall contain a checklist of all function tests performed. Depending on the vendor this report may be entitled "Quality Control Checklist." Post-inspection function tests may include but are not limited to:

8.7.1.1 Tool cleanliness and visual inspection;

8.7.1.2 Confirmation that an adequate power supply was available and operational;

8.7.1.3 Confirmation that all sensors, data storage, odometers and other mechanical systems operated properly;

8.7.1.4 Confirmation that adequate data storage was available; and

8.7.1.5 Examination of tool for damage and significant wear.

8.7.2 Survey Acceptance Criteria

The IE shall apply the survey-acceptance criteria provided below to determine if the tool operated correctly and if the data will be of acceptable quality.

8.7.2.1 *Physical damage to tool and its components*: The tool shall be visually examined as soon as possible following the inspection to give a quick indication of the potential need for a re-inspection. The field log or data summary shall be reviewed to confirm the time of the damage and the impact of that damage on the data collected.

8.7.2.2 *Lost sensor channels on data*: When a field or preliminary log is reviewed, sensor channels that stopped obtaining data should be readily evident. Loss of sensor channels may still be acceptable, especially in cases where the lost channels were not adjacent. Sensor loss of up to 5% of the tool data can be accepted for lines that have been previously inspected, have a good history and operate at less than or equal to 40% of the SMYS. Lines that operate above 40% of the SMYS and are susceptible to linear threats can only tolerate a 1% sensor loss.

8.7.2.3 *Sensor noise*: Damaged sensor or bad electrical connections can make a sensor channel noisy, creating signals that mask out adjacent good channels. Noisy channels are also readily evident on the log and shall be addressed in the same manner as lost sensor channels.

8.7.2.4 *Distance inaccuracy*: Inaccurate distance recording can create significant problems when trying to locate anomalies for verification or repair. For lines less than and up to 60 miles, distance errors of up to 1% can be tolerated. For lines greater than 60 miles the distance error threshold shall be 0.5%.

8.7.2.5 *Missed or not recorded features*: The occurrence of undetected or not recorded features that are known to exist from prior inspection or pipeline design information shall be investigated to determine the cause. Missing known flange sets, valves or large diameter tees brings the veracity of all log information into question.

8.7.2.6 *Velocity under-runs or over-runs*: When tool velocities exceed the ILI vendor's upper limits, data detection and sizing accuracy can be degraded. The IE shall review the distance affected by the velocity excursions and assess the impact that this will have on the integrity of the pipeline. Speed excursions that exceed 2% beyond vendor specifications require further consideration to determine if the run is acceptable.

8.7.3 Determining if a Re-Inspection is Required

Within 24 hours the ILI vendor shall provide the IE information on the performance of the intelligent tool. Failure to meet the acceptance criteria outlined in §8.7.2 does not immediately constitute an unsuccessful run. The IE and ILI vendor shall review the results of each inspection on a case-by-case basis and jointly decide if a re-inspection is required, taking all factors into consideration. If a re-inspection is necessary, the IE shall immediately notify all stakeholders to begin the re-inspection process.

8.7.3.1 The re-inspection shall not be conducted until the process parameters that led to the tool navigation problems can be addressed and modified to ensure a successful re-inspection.

8.7.3.2 If data is accepted with known sensor loss, distance inaccuracies, or velocity excursions, the effect of these discrepancies on the data quality (e.g., acquisition and sizing) shall be defined to allow the IE to effectively manage the issue.

8.7.4 Accepting the ILI Run

The IE shall notify the EPM if the inspection run is acceptable. The EPM shall communicate the acceptance decision to all stakeholders so that the de-mobilization process can begin.

8.8 Post Tool Run Documentation

8.8.1 ILI Run Record

The IE shall complete the ILI Run Record (**Form F**). The form contains vendor and Company contact information, technical information on the ILI tool, acceptance criteria results, summary of ILI tools launched and received and other pertinent data.

8.8.2 Assessment Completion Form

The IE shall complete an Assessment Completion Form (ACF) in accordance with Company **Form ACF**. The completed form, including identification of short segments as discussed in §7.7 will be reviewed by the AM to check for completeness and verify that the short segment evaluation does not exceed 5% of the total inspection length. Upon completion of review, the IE will submit the ACF electronically to the Assessment Records Group for tracking.

8.8.3 Post-Run Operational Report

The IE shall request a Post-Run Operational Report from the ILI vendor that at minimum includes the following information:

8.8.3.1 Pipeline name;

8.8.3.2 Date of run;

8.8.3.3 Length and diameter of run;

8.8.3.4 Any significant tool modifications for run;

8.8.3.5 Average speed of run, speed profile or both;

8.8.3.6 Run success or failure; and

8.8.3.7 Length and diameter of run;

8.8.3.8 If failed, reason for failure and associated remedial work;

8.8.4 Other Reports

The IE shall obtain the following reports:

8.8.4.1 ILI Run Sheet from Construction Manager;

8.8.4.2 ILI Cleaning report from Construction Team Leader;

8.8.4.3 Chain of Custody record from the Chemical/Environmental Group at the EAC.

8.9 Summary

The In-line inspection process is summarized in **Figure 5**.

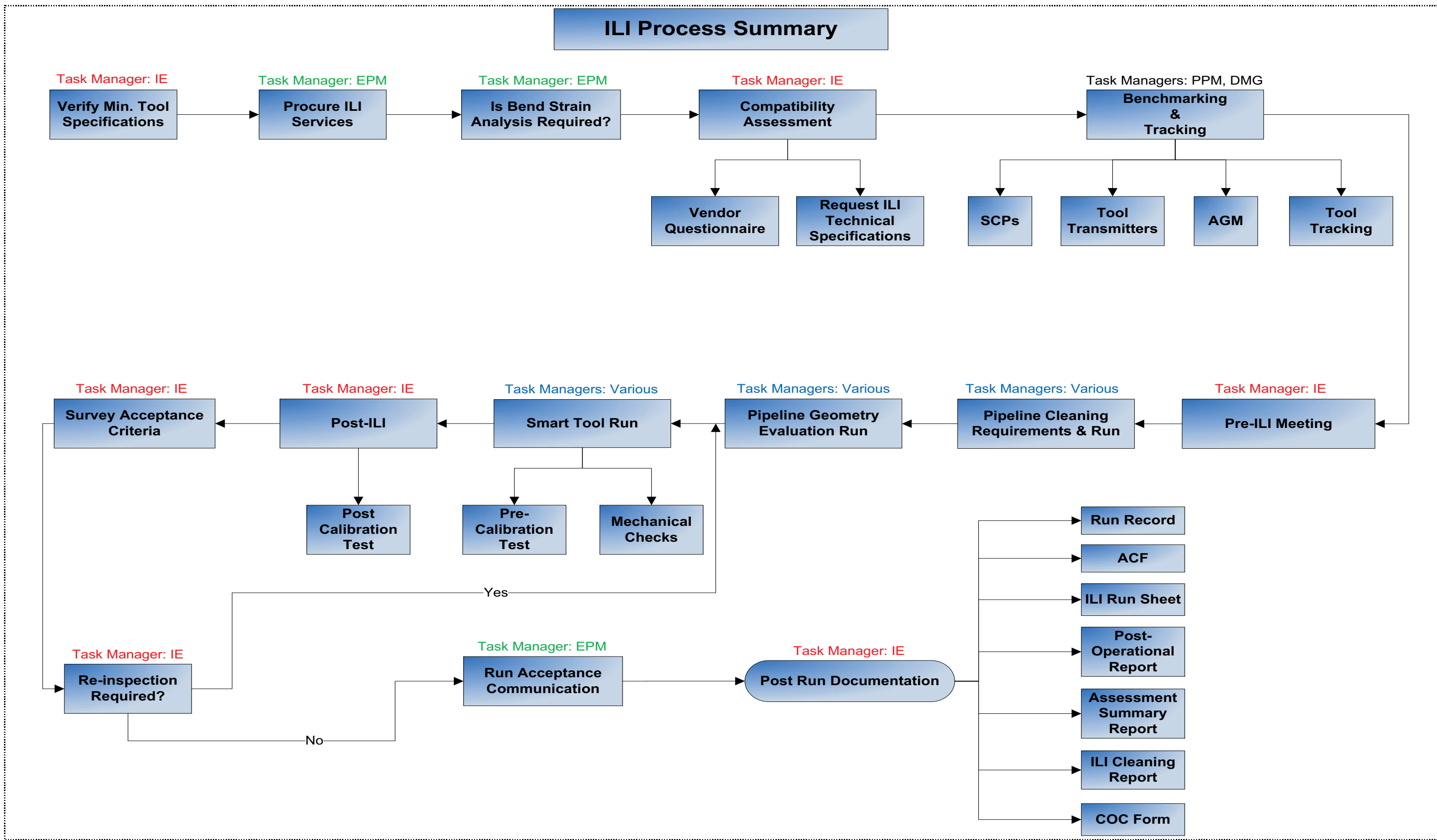


Figure 5: ILI Process Summary

9.0 ILI REPORTING REQUIREMENTS & DATA ANALYSIS

ILI vendors have applicable algorithms and software to analyze data. The results of the analyses shall be within tool specifications for detection capabilities, accuracies, confidence intervals, minimum detection levels and detection thresholds. The ILI vendor shall adhere to the data analysis and reporting requirements outlined in **Standard 167.0220,** which provides specifications for clustering and interaction rules, pressure-based analyses and calculations, spatial alignment and other DMG-related analyses.

9.1 Reporting Requirements

9.1.1 Preliminary ILI Pipeline Tally

Within 30 days of completion of an inspection the ILI vendor shall provide a preliminary ILI pipeline tally to the IE. The 30-day time will start upon the successful completion of the inspection. The purpose of the tally is to perform a spatial alignment and initial quality assurance check prior to issuance of the final ILI report. Therefore, the preliminary report shall only contain information on pipeline features (e.g., girth weld, taps, valves, etc.) and not pipeline anomalies in order to expedite the delivery.

9.1.2 Initial Quality Assurance Review

Pressure-based analyses and calculations are dependent on correct data inputs. Significant errors will occur in failure pressure and rupture pressure ratio calculations if the wrong diameter, grade, wall thickness, etc. are inputted. The IE shall review the preliminary ILI pipeline tally and verify the vendor data matches Company data for the following pipeline attributes:

9.1.2.1 Diameter;

9.1.2.2 Wall thickness;

9.1.2.3 Grade; and

9.1.2.4 MAOP

9.1.3 Spatial Alignment Review

The DMG shall perform all spatial alignment analyses including but not limited to the following:

9.1.3.1 Verify that geospatial distances (GPS-derived) agree with ILI report odometer distances.

9.1.3.2 Verify that the AGMs and SCPs used to align primary sensor data match the original Company-provided AGM/ SCP pipeline features.

9.1.3.3 Verify that there are no significant deviations when the reported pipeline geometry is superimposed onto Company maps.

9.1.3.4 Verify, and if necessary, resolve discrepancies between the distance generated by the report odometer and the coordinate distance generated by the ILI vendor's inertial navigation system (INS) mapping tool.

The DMG shall communicate the results of the spatial alignment analysis to the IE. The DMG and IE shall collaborate with the ILI vendor to correct any discrepancies found in the data. If both the spatial alignment and quality assurance reviews are successful, the IE shall notify the ILI vendor to begin processing the final ILI report.

9.1.4 Final ILI Report

The ILI vendor shall submit the final ILI report to the IE within 60 days of the assessment date. The IE shall stamp the receipt date on the report and notify all stakeholders. The report format shall comply with the requirements in **Standard 167.0220**.

9.1.5 Final Quality Assurance Review

The IE shall perform a second and final quality assurance review of the final ILI pipeline tally. The IE shall verify that the following pipeline parameters were utilized correctly.

9.1.5.1 Diameter;

9.1.5.2 Wall thickness;

9.1.5.3 Grade;

9.1.5.4 MAOP;

9.1.5.5 Changes in the above parameters (if applicable) are accurately reflected;

9.1.5.6 Equations used to calculate the predicted failure pressures and rupture pressure ratios;

9.1.6 Verification of Contractual Requirements

The ILI vendor shall adhere to all contractual requirements in **Standard 167.0220**. The EPM shall review the vendor deliverables and verify that all terms and conditions were met. Final payment for ILI services shall be initiated once the EPM has verified all vendor submittals. The EPM shall inform the PPM that final payment can be processed.

9.2 Data Analysis

The IE shall evaluate all anomalous indications in the final ILI report. A prioritization schedule shall be established to address those anomalous indications that could reduce the pipeline's integrity. When establishing a prioritization schedule, indications shall be categorized into the groups described below. A more detailed description of each indication is provided in §9.3.

9.2.1 Immediate Indications

Indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline.

9.2.2 Scheduled Indications

Indications that show an anomaly is significant but not at failure point.

9.2.3 Monitored Indications

Indications that show an anomaly will not fail before the next inspection.

Upon receipt of the final ILI report, the IE shall promptly review the results for immediate indications since these pose the greatest integrity threat to the pipeline and have the highest priority. Scheduled and monitored indications have second and third priority. Additional details on failure and rupture pressure ratio (RPR) calculations and general description of corrosion profiles are provided in **Standard 182.0050**.

In addition, the IE shall compare prioritized indications from the current assessment to those from the last integrity assessment to determine whether they are new indications or monitored indications that have changed to a more severe priority. The IE shall schedule the evaluation of indications that have a response time before the next assessment interval.

9.3 Response to Reported Anomalies

9.3.1 Discovery of an Integrity Condition

Discovery of a condition occurs when sufficient information exists that the condition presents a potential threat to the integrity of the pipeline. Sufficient information shall be obtained no later than 180 days following the date the last in-line inspection tool run of a scheduled series of tool runs is performed and deemed successful, unless it can be demonstrated that the 180-day period is impractical.

9.3.2 Immediate Response/Repair Conditions

Immediate response or repair conditions have the highest priority and shall be evaluated within 5 days of discovery (receipt of final ILI report). Immediate response/repair conditions are described in full detail in **Standard 167.0235.** Conditions requiring an immediate response and applicable reference(s) are provided in **Table 7**.

Table 7: Immediate Response Conditions

	Condition	Reference
1.	A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the MAOP at the location of the anomaly.	49 CFR Part 192 §192.933 & ASME B31.8S
2.	A dent that has any indication of metal loss, cracking or a stress riser.	49 CFR Part 192 §192.933 & ASME B31.8S
3.	An indication or anomaly that in the judgment of the IE requires immediate action.	49 CFR Part 192 §192.933
4.	Corrosion anomalies with metal loss in excess of 80% of the pipe wall thickness.	ASME B31.8S
5.	Metal loss affecting an ERW or flash-welded longitudinal seam.	ASME B31.8S
6.	Indications where likely near-term leaks or ruptures could occur.	ASME B31.8S
7.	Indications of SCC.	ASME B31.8S

9.3.3 Temporary Pressure Reduction

When an immediate repair condition has been discovered a temporary reduction in the operating pressure shall be implemented to ensure the safety of the impacted pipeline segment. The temporary reduction in pressure shall be implemented using one of the following two methods:

9.3.3.1 (PREFERRED) The first method is to reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered.

9.3.3.2 The second method is to reduce the operating pressure to a level that is calculated by multiplying the predicted failure pressure, P_f, by a factor of safety that is based on class location.

9.3.3.3 For Class 1 locations, reduced operating pressure = P_f x 0.72;

9.3.3.4 For Class 2 locations, reduced operating pressure = P_f x 0.60;

9.3.3.5 For Class 3 locations, reduced operating pressure = P_f x 0.50;

9.3.3.6 For Class 4 locations, reduced operating pressure = P_f x 0.40.

9.3.4 Scheduled One-Year Conditions

Scheduled one-year conditions have the second highest priority and shall be remediated within one year of discovery of the condition. One-year conditions along with the applicable reference(s) are shown in **Table 8**.

Table 8: Scheduled One-Year Conditions

	Condition	Reference
1.	A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than nominal pipe size (NPS) 12).	49 CFR Part 192 §192.933 & ASME B31.8S
2.	A dent with a depth greater than 2% of the pipelines diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.	49 CFR Part 192 §192.933 & ASME B31.8S
3.	Mechanical damage with or without concurrent visible indentation of the pipe.	ASME B31.8S

9.3.5 Monitored Conditions

Conditions in this category do not have to be assessed for remediation but must be recorded and monitored until the next scheduled integrity re-assessment. Monitored conditions along with the applicable reference(s) are shown in **Table 9**.

Table 9: Monitored Conditions

	Condition	Reference
1.	A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than nominal pipe size (NPS) 12) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).	49 CFR Part 192 §192.933
2.	A dent located between the 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for pipeline diameter lest than NPS 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.	49 CFR Part 192 §192.933
3.	A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties	49 CFR Part 192 §192.933

9.3.6 Other Scheduled Conditions

Indications characterized with a predicted failure pressure greater than 1.10 times the MAOP shall be examined and evaluated according to a schedule established by **Figure 6**. The figure contains three plots of the allowed time to respond to an indication based on the SMYS of the pipeline and the ratio between the predicted failure pressure and MAOP. The three plots correspond to:

9.3.6.1 Pipelines operating at pressures above 50% of SMYS;

9.3.6.2 Pipelines operating at pressures above 30% of SMYS but not exceeding 50% SMYS; and

9.3.6.3 Pipelines operating at pressures not exceeding 30% of SMYS.

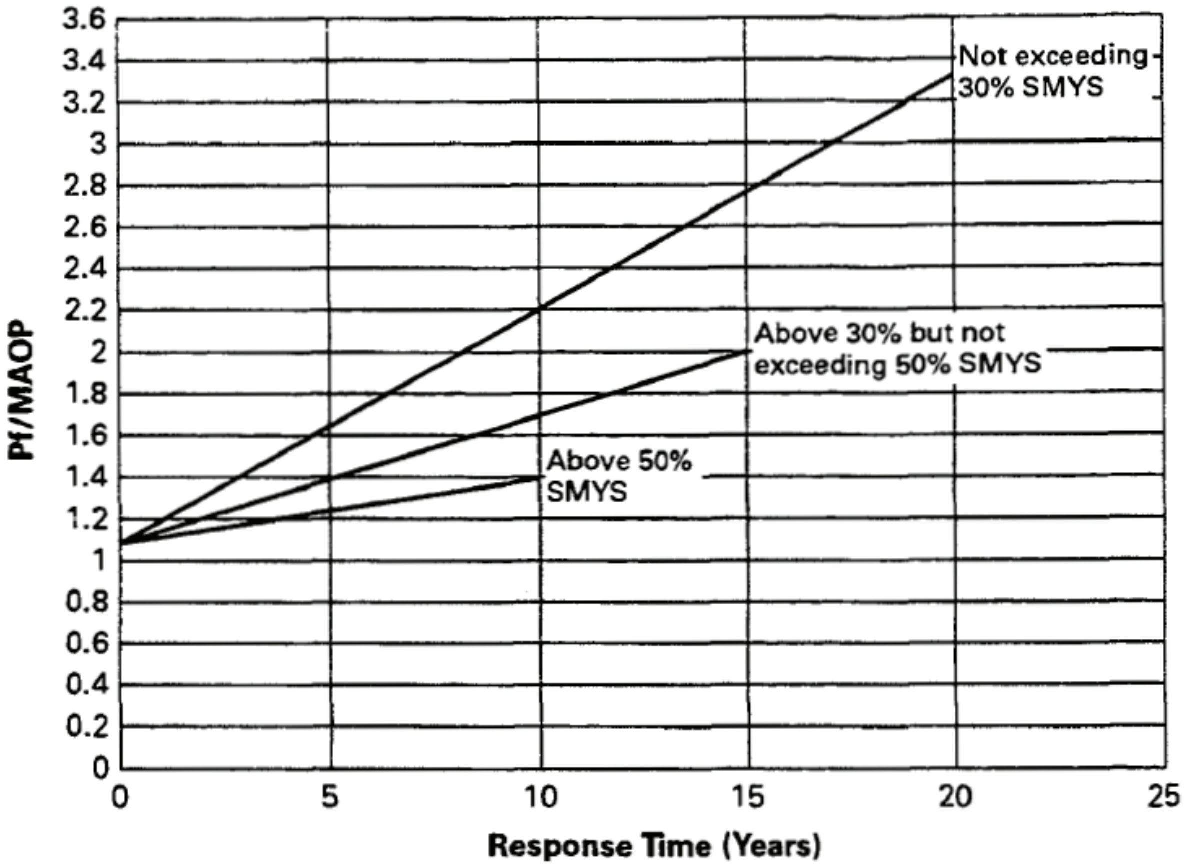


Figure 6: Timing for Other Scheduled Response Conditions[1]

9.3.7 Safety Related Conditions

Safety related conditions (SRC) are outlined 49 CFR Part §191.23 and §191.25. SRCs must be evaluated within 5 days and remediated within 10 days as required by the aforementioned sections. A temporary reduction in the operating pressure shall be implemented as outlined in §9.3.3. An SRC report must be filed with the Office of Pipeline Safety for all SRCs that are not remediated within the 10-day deadline. Additional guidelines on identifying and reporting safety related conditions are provided in **Standard 183.06**.

[1] Extracted from §7 of ASME B31.8S.

9.3.8 Integrity Inspection Report

The IE shall summarize the results of the ILI data analysis using the Integrity Inspection Report. The report shall provide detailed description and breakdown of anomalies detected by the ILI tool, comparison of prioritized indications from the current assessment to those from the last integrity assessment, analysis of short segments (refer to §7.7), prioritization schedule and quality assurance reviews of ILI data (refer to §§9.1.2 and 9.1.5).

9.3.9 Prioritization of Response Indications

The IE shall schedule a meeting with the AM to discuss the prioritization of anomalous indications for physical evaluation. Prioritization of indications shall be as follows:

9.3.9.1 **Priority 1**: Immediate Response Indications and SRCs;

9.3.9.2 **Priority 2**: Scheduled Response Indications (49 CFR Part 192 §192.933 & ASME B31.8S) and Other Scheduled Response Indications (ASME B31.8S);

9.3.9.3 **Priority 3**: Monitored Response Indications.

The IE shall record the meeting discussion using the Prioritization Meeting for Response Indications form (**Form H**).

9.3.10 Other Reporting Requirements

The reports outlined below are contained within the final ILI report. The IE shall submit these reports to the appropriate departments for further evaluation.

9.3.10.1 The bend strain report (if applicable) shall be routed to the Engineering Design Department.

9.4 Selection of Dig Sites

The IE shall determine which anomalous indications require visual examination. Digs shall be categorized into one of the groups described below.

9.4.1 Immediate Response Indication/SRC Digs

Digs in this category contain indications that warrant an immediate response or are SRCs as described in §§9.3.2 and 9.3.7. These digs shall receive the highest priority and all time deadlines for completing these digs shall be strictly adhered to. The number of digs in this category is not limited.

9.4.2 Validation Digs

The purpose of the validation dig is to assess the accuracy of reporting and attempt to correlate actual versus reported conditions. The IE shall make every effort to select digs that contain indications with a wide range of corrosion depths to evaluate how the ILI tool performed within each wall loss interval. A minimum of two validation digs shall be required per ILI run.

9.4.3 Remediation Digs

All other digs shall fall into this category. These digs include indications that fall into the scheduled response, other scheduled response or monitoring response condition. Remediation digs shall be completed within the time frames required for each indication evaluated. The number of digs in this category is not limited.

9.4.4 Other Type Digs

The IE shall collaborate with the Preventive and Mitigative Measures Groups to determine if additional integrity-related digs are required. These additional excavations may not contain anomalies that correlate with the ILI data. The number of digs is this category is not limited.

9.4.5 Dig Selection Summary

The IE shall complete the Dig Locator (**Form I**) and Dig Selection Summary (**Form J**). The Dig Locator is in Microsoft Excel format and contains logistical information on the excavation such as a sketch depicting distances to upstream and downstream references from the target anomaly, listing of other anomalies expected within the excavation and two aerial maps. The Dig Selection Summary contains anticipated response information such as whether repairs are anticipated and/or a reduction in pressure is required.

9.4.6 Bellhole Siting

Once the dig selection process has concluded, the IE shall submit the Dig Locator and Dig Selection Summary forms to the DMG for siting. Bellhole siting is the act of physically locating excavation sites using GPS technology or surface chaining.

9.4.6.1 *GPS Coordinates*: The most accurate and efficient method of siting is by means of sub-meter GPS equipment using the IMU data contained within the final ILI report.

9.4.6.2 *Surface Chaining*: In the absence of IMU data surface chaining may be used, although this process can result in location errors since the distance along a pipeline may not always match the distance the ILI tool travels inside the pipeline. Chaining shall be from both an upstream and a downstream reference feature or benchmark to bracket the anomaly location.

9.4.6.3 The DMG shall submit a siting report to the IE at the conclusion of the bellhole siting process.

9.4.7 Environmental Assessment

The IE shall submit the Dig Locator and Dig Selection Summary to the Pipeline Integrity Environmental Services group to perform an environmental assessment of the proposed excavation area. Environmental conditions and permitting must be considered (especially in environmentally sensitive areas such as wetlands) in preparation for the possibility of excavation to visually examine an indication or required pipe repair or replacement. Significant costs and delays in permitting can be incurred if the pipe section is located in an environmentally or ecologically sensitive area. Pipeline Integrity Environmental Services shall communicate the results of the environmental assessment to the IE.

9.4.8 Alternate Dig Selection

The IE shall consider any restrictions that result from the bellhole siting or environmental assessment and determine if an alternate excavation is required. Alternate dig selections are only allowed for validation, remediation and other type excavations that do not contain indications that pose a hazard to the integrity of the pipeline.

9.4.9 Dig Selection Meeting

The purpose of the Dig Selection Meeting is to review the Dig Locator, Dig Selection Summary and results of the bellhole siting and environmental assessments performed for each excavation. The IE shall invite the PPM, DMG, Gas Transmission and Pipeline Integrity Environmental Services to the meeting. Any changes such as the selection of alternate digs or alignment errors noted during the bellhole siting shall be addressed at the meeting. The IE shall keep a record of the meeting using the Dig Selection Meeting Minutes form (**Form K**).

9.4.10 Documenting the Dig Selections

The IE shall input the scheduled digs into the Direct Exam & Remediation Schedule.xlsx file.

9.5 Summary

The ILI Data Analysis and Reporting Requirements process is summarized in **Figure7**.

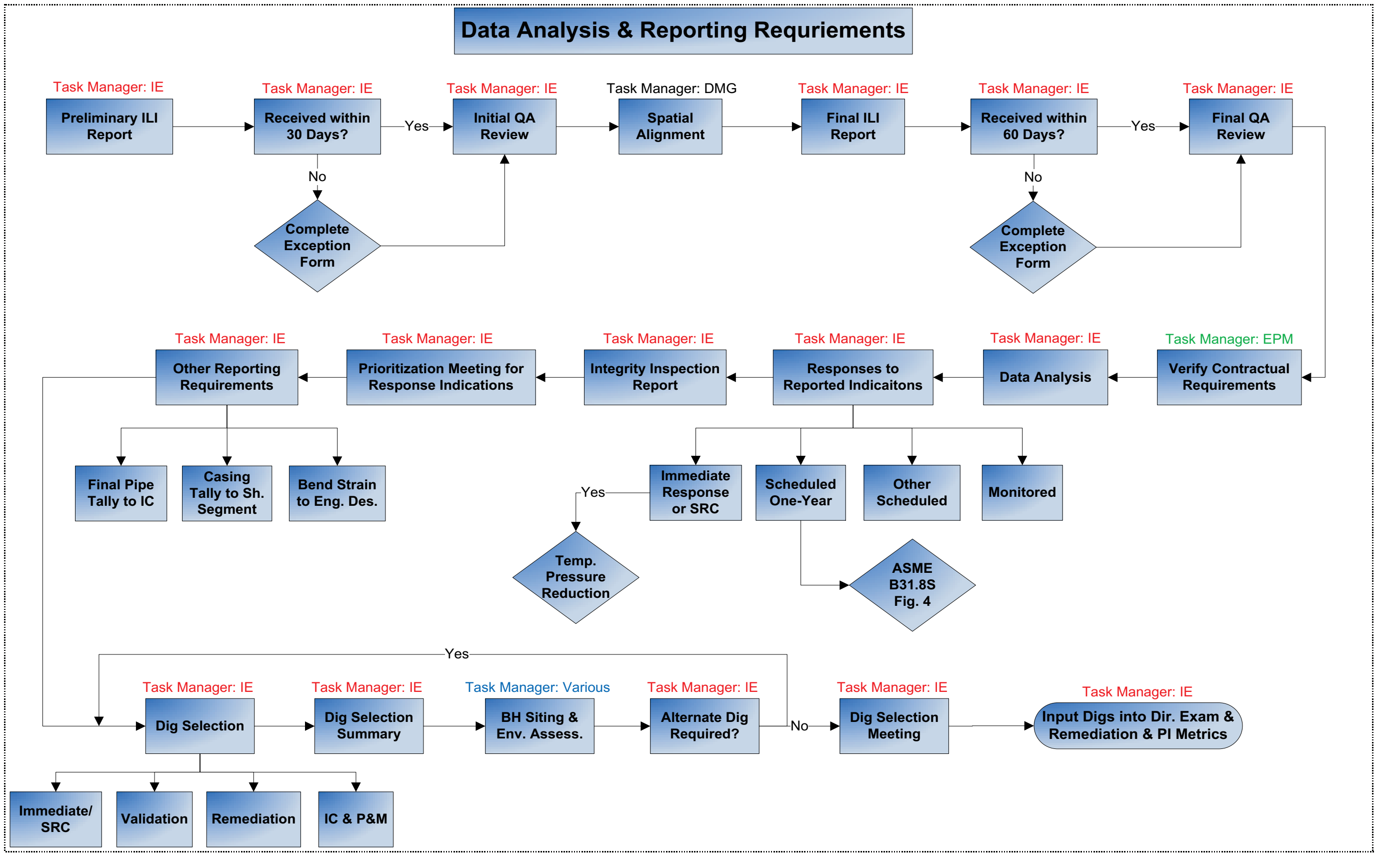


Figure 7: ILI Data Analysis & Reporting Requirements Summary

10.0 DIRECT EXAMINATION

Direct examination is the physical evaluation of the pipeline using non-destructive techniques. The objectives of the direct examination process are to: (a) perform a comprehensive bellhole inspection of the pipe section containing the target anomaly; (b) remediate anomalies that have reached critical values; and (c) establish a correlation between ILI reported results and actual field measurements. Direct examinations require coordination with property owners (if applicable) and permitting agencies to discuss post restoration activities. Restoration can include grading, grass planting, replacement of trees, installation of various plants, the replacement of driveways and parking lots. When work disturbs existing sidewalks and roadways, state and local jurisdictions will impose restoration requirements as a condition of the permit.

10.1 Preparing the Pipeline for Assessment

Gas Transmission shall be responsible for preparing the pipeline for assessment. The siting report generated by the DMG shall be used to locate the excavation site.

10.1.1 Excavation

The pipe shall be excavated in accordance with **Standard 184.0175** and **Standard 223.0140**. Environmental guidelines shall be strictly adhered to as outlined in **Manual TIMP.11**.

10.2 Bellhole Inspection

All bellhole inspection activities including field measurements and anomaly documentation shall be conducted in accordance with **Standard 167.0211**.

10.2.1 Exporting the Inspection Text Files

The IE shall generate inspection text files using the Bellhole Inspection Database for each excavation selected. The IE shall complete the “Identification” and “Background” tabs, export the newly created bellhole form, and forward to the IP performing the inspection. The IP shall populate all remaining tabs in the bellhole form using a hand held Trimble GPS device.

10.2.2 Site Verification

The IE or IP shall perform a secondary verification to ensure that the proper pipe joint has been excavated. Secondary techniques to verify the proper anomaly is being investigated are provided below. This process is facilitated by using a dig sheet provided by the ILI vendor.

10.2.2.1 The long seam orientations for the upstream, downstream and target joints shall be compared with vendor data.

10.2.2.2 The distance of the target anomaly to the upstream or downstream girth weld shall closely match the vendor distances.

10.2.2.3 The joint lengths of the upstream, downstream and target anomaly shall closely match the joints lengths in the ILI report or dig sheet.

10.2.3 Anomaly Categorization

The IE shall provide the IP with pertinent information to perform the required inspection at each bellhole site. Information can include vendor-provided dig sheets showing all anomaly characteristics and references, the Dig Locator and Dig Summary. Anomalies identified during the bellhole inspection shall be categorized as follows:

10.2.3.1 Category 1: Anomalies detected by the ILI tool and correlated by field measurements.

10.2.3.2 Category 2: Anomalies detected by the ILI tool, however, field measurements determined that either the anomalies do not exist or the anomalies exist but were not properly classified by the ILI vendor;

10.2.3.3 Category 3: Anomalies that were not detected by ILI tool but were discovered during the bellhole inspection.

The pipeline inspector will perform the following tasks based on the category of the anomaly:

10.2.3.4 Category 1: Locate, measure, document and photograph anomalies. The ILI anomaly number provided in the ILI report shall be used for labeling.

10.2.3.5 Category 2: Locate, measure, document and photograph anomalies. The ILI anomaly number provided in the ILI report shall be used for labeling. There may be cases where the ILI vendor identifies an external metal loss anomaly that could not be field-verified by the IP. In this situation, the IP shall perform a UT inspection of the area to determine if the anomaly was misclassified and is in fact an internal or mill flaw anomaly.

10.2.3.6 Category 3: Locate, measure, document and photograph anomalies. These anomalies shall be labeled in accordance with **Standard 167.0211**.

10.2.4 Expanding the Excavation

The IE shall determine if the excavation requires expansion to examine anomalies that visually appear to be critical. These anomalies are located beneath coating in the upstream or downstream joints that may only be partially visible. The IE shall collaborate with Gas Transmission personnel to determine the extent of expansion.

10.2.5 Importing the Inspection Text Files

At the conclusion of the bellhole inspection, the IP shall submit the completed bellhole form to the IE for review. The IE shall ensure that all tabs in the bellhole form were properly populated, particularly the tab on corrosion anomalies, since information in this tab shall be used to perform defect assessment calculations.

10.2.6 Discovery of an Immediate Response/Safety Related Condition

"Discovery" must be declared upon completion of the direct examination process if an immediate response or safety related condition is found that was not identified by the ILI tool. Response requirements for such conditions shall be performed in accordance with §§9.3.2, 9.3.3 and 9.3.7.

10.3 Defect Assessment

The IE shall perform a defect assessment of anomalies identified in the bellhole inspection report to determine if critical levels have been attained. Additional details on defect analysis are provided in **Standard 167.0236**.

10.3.1 Remaining Strength Evaluation of Corroded Pipe

The remaining strength of each critical anomaly shall be evaluated using KAPA. KAPA calculates an estimated failure pressure and operating safety factor of pipe impacted by either a blunt metal-loss defect or a crack-like defect in accordance with several published methodologies that are widely used in the industry. For blunt metal-loss defects, such as those caused by corrosion, KAPA calculates the estimated failure pressure according to three methods: ASME B31G, “Modified B31G” method also known as the “0.85-dL” method and the “Effective Area” method.

10.3.2 Corroded Girth Weld Analysis

Circumferentially oriented corrosion defects impacting a girth weld may be evaluated using the “Serviceability of Corroded Girth Weld” analysis, or other appropriate engineering critical analysis method. The guidelines are based on an engineering criterion that accounts for the geometric measurements of the corroded area, the material strength properties, the presence of fabrication flaws in the girth weld, and the operating conditions of the pipeline.

10.3.3 Predicted Failure Pressure Calculation

The IE shall calculate the failure pressure for each corroded area in accordance with **Standard 182.0050**.

10.3.4 Integrity Timeframes

Determination of integrity conditions shall be made as soon as practicable after discovery of such condition, but no later than 5-working days (excluding Saturday, Sunday or federal holidays) after discovery.

10.4 Remediation

The IE shall determine the applicable remediation requirements in accordance with **Standard 167.0236**.

10.4.1 Repair Methods

10.4.1.1 All defects requiring repair shall be remediated in accordance with **Standard 223.0180**.

10.4.2 Finalizing the Bellhole Inspection Report

The IE shall finalize the Bellhole Inspection Report and save in the Bellhole Inspection database. The report shall contain results of the defect assessment and summary of repairs conducted at each excavation, if applicable.

10.5 Root Cause Analysis

10.5.1 Objective

To identify the likely causes of corrosion or pipe damage to determine:

10.5.1.1 The likelihood that similar corrosion damage will occur elsewhere in the pipeline;

10.5.1.2 If the degradation is from a historic or active mechanism; and

10.5.1.3 Recommendations to mitigate the degradation.

10.5.2 Process

The IE shall perform a root-cause analysis of each indication associated with a significant external corrosion condition or other form of pipe damage which affects the MAOP of the pipeline.

10.5.3 Analysis Content

The analysis should discuss the following aspects:

10.5.3.1 Coating Failure: The extent and cause of coating failure, including discussion regarding whether the damage is localized or widespread.

10.5.3.2 Cathodic Protection Ineffectiveness: Historical readings shall be evaluated to determine the effectiveness of CP in the area.

10.5.3.3 Corrosion Mechanism: Identify the main drivers for corrosion in the area including soil chemistry, pH, moisture, corrosive microbes, etc. Is the corrosion active or historic?

10.5.3.4 Mitigative Measures: Identify potential mitigative measures to impede or arrest corrosion at the locations which contribute to the root cause.

10.5.3.5 Documentation: The root cause of significant corrosion conditions shall be documented. A root cause analysis may cover multiple conditions provided that the conditions share similar characteristics.

10.6 Discovery and Determination Report

The IE shall document the discovery and determination of integrity conditions using the Discovery and Determination Report (**Form L**). Remediation and root cause analysis of each critical condition discovered shall be included. RSTRENG or KAPA analyses shall be attached as separate supporting documentation.

10.7 Assessment of ILI Tool Performance

The IE shall be responsible for assessing and verifying the performance of the ILI tool. The performance assessment consists of a number of separate tool measures including probability of detection, probability of identification and sizing accuracy.

10.7.1 Probability of Detection

The probability of detection (POD) is the number of anomalies correctly detected and reported by the ILI tool divided by the total anomalies at each excavation.

10.7.2 Probability of Identification

An ILI tool can sometimes detect and report a pipeline anomaly but misidentify its type. The probability of identification (POI) is the ratio of anomalies correctly identified to the total number of anomalies identified at each excavation.

10.7.3 Sizing Accuracy

Sizing accuracy is the measure of the tools ability to report the correct size of certain types of corrosion anomalies. The standard method of comparing ILI depths to field measured depths is on a unity graph. A unity graph plots each anomaly as a point on an x-y plot. The x-coordinate is the field depth and y-coordinate is the ILI measured depth. An example of a unity graph is depicted **Figure 8** below.

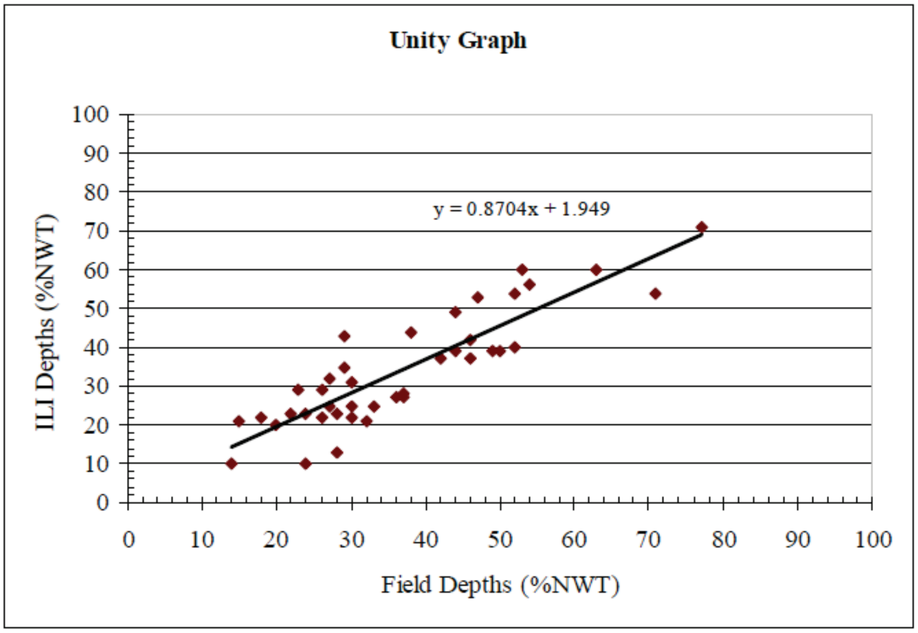


Figure 8: Example Unity Graph

10.8 Probability of Exceedance

Probability of Exceedance (POE) is a statistical analysis method that evaluates the probability of the likelihood of a leak and rupture of pipelines. The method is based on statistical analysis of errors in inspection tool predictions against field measurements. In POE analysis, the probability of failure is described by the probability of an actual defect size exceeding a given critical value, or by the probability of rupture pressure calculated from an actual defect below the MAOP.

10.8.1 Results of POE Analysis

The IE shall perform the POE analysis using the template available within the Company server. The IE shall use the results of the POE to determine if additional digs are required. These digs shall be identified as Remediation Digs. A unity graph is generated from the POE analysis showing the sizing accuracy of the tool.

10.9 Corrosion Growth Rates

The IE shall determine the corrosion growth in accordance with **Figure 8**. The corrosion growth rates are summarized below and are a function of the operating stress of the pipeline. In all equations, t, refers to the measured wall thickness.

10.9.1 Pipeline Operating at 72% of SMYS

The corrosion growth rate, in mils per year, for a pipeline operating at stress level of 72% of SMYS:

$$\mathbf{R_{72} = 28t\ [SMYS/(SMYS + 10{,}000]}$$

10.9.2 Pipeline Operating at 50% of SMYS

The corrosion growth rate, in mils per year, for a pipeline operating at stress level of 50% of SMYS:

$$\mathbf{R_{50} = 33t\ [SMYS/(SMYS + 10{,}000]}$$

10.9.3 Pipeline Operating at 30% of SMYS

The corrosion growth rate, in mils per year, for a pipeline operating at stress level of 30% of SMYS:

$$\mathbf{R_{30} = 35t\ [SMYS/(SMYS + 10{,}000]}$$

10.10 Summary

The Direct Examination process is summarized in **Figure 9** below.

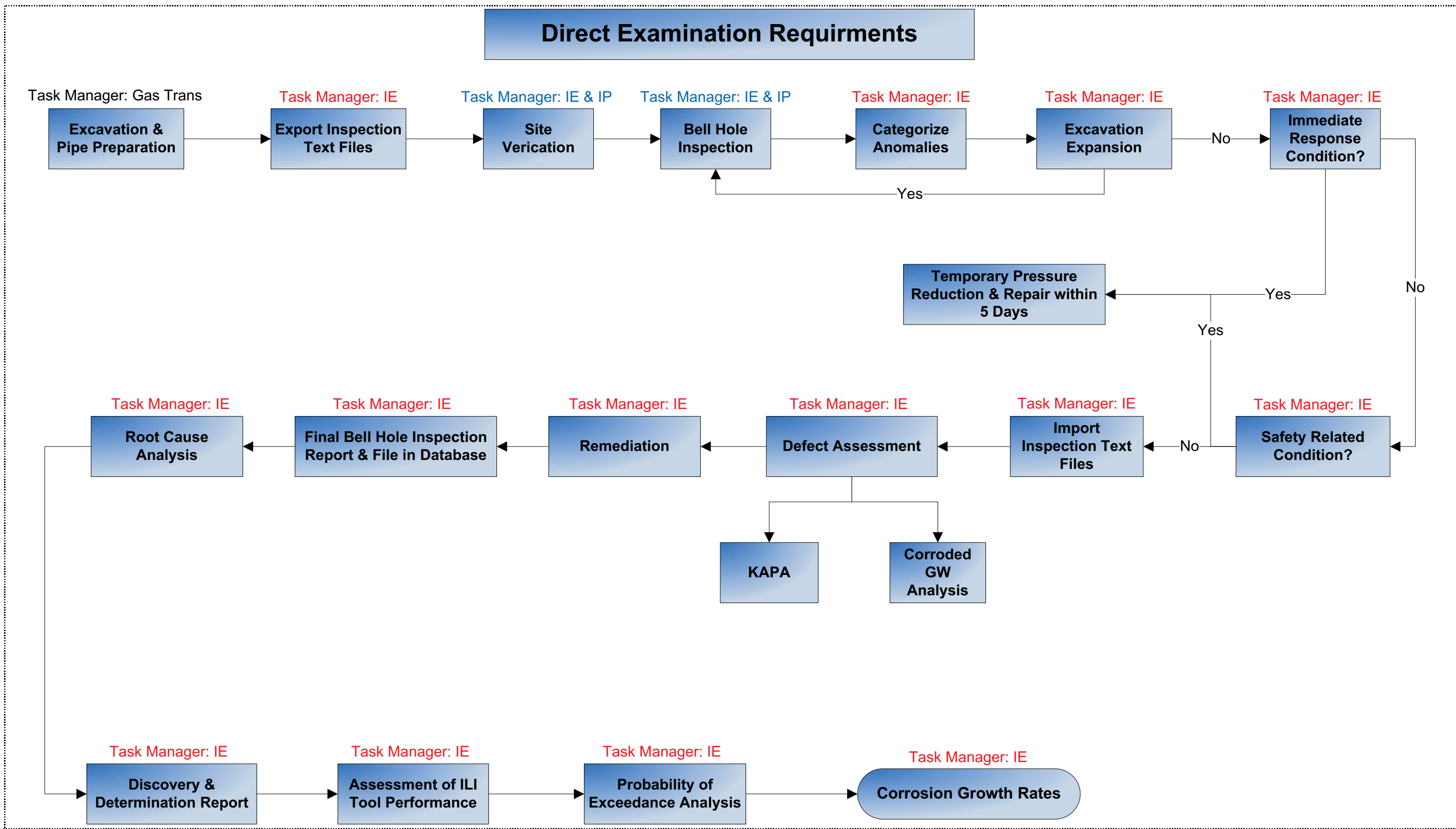


Figure 9: Direct Examination Summary

11.0 POST ASSESSMENT

11.1 Direct Exam Results Meeting

11.1.1 Objective

The IE shall communicate the results of the ILI project to operating personnel and the Preventative & Mitigative Measures Team to initiate development of preventative actions.

11.1.2 Agenda

The IE and AM shall organize the meeting and present the results of the direct examination. Other team members may be invited to the meeting.

11.1.3 Results

The IE shall document the results of the meeting using the Direct Exam Meeting Minutes form (**Form M**).

11.2 Update ILI Vendor of Results

The IE shall provide feedback of the field inspection results to the ILI vendor. Using this information the ILI vendor can continuously improve the validity and accuracy of the data analysis.

11.3 Submittal of ACF for Short Segments

The IE shall submit a completed ACF for the assessed short segments. The completed form, including identification of short segments as discussed in §7.7 will be reviewed by the AM to check for completeness and verify that the short segment evaluation does not exceed 5% of the total inspection length.

11.4 Establishing Re-Assessment Intervals

Re-assessment intervals are determined by the Line Assessment Summary Spreadsheet contained within the Integrity Inspection Report. However, the maximum re-assessment interval by any allowable re-assessment method is seven years.

11.5 PI Performance Metrics

The IE shall complete the Performance Metrics Spreadsheet including inputting information on all anomalies discovered in the bellhole, remediation activities, etc.

11.6 Change of Threat Documentation

When applicable, the IE shall complete **Form F4-1** to document changes or updates to the threat assignments of a covered segment in accordance with **Standard 167.0203**.

11.7 Direct Exam and Remediation Schedule

The IE shall complete Direct Exam and Remediation Schedule spreadsheet.

11.8 Request Pipe Condition and Maintenance Reports

The IE shall request Pipe Condition and Maintenance Reports (PCMRs) from the Construction Manager. PCMRs shall be filed in the project folder.

11.9 Pipeline Database Updates

The IE shall document changes to pipeline attributes, pipeline features or other noteworthy conditions/site locations noted using Company **Form 2112**. The IE shall review the instructions to ensure all applicable information is properly documented.

11.10 Final ILI Report

The IE shall complete a final comprehensive ILI report that summarizes the results of all activities associated with the pipeline survey. The report shall be filed in the project folder.

12.0 RECORDS

The retention period shall be LOA+5 (life of the asset plus five years) in accordance with the Corporate Retention Schedule for the following records:

- ILI Forms (A through M)
- Bellhole Inspection Records
- **Form 2112** for physical changes to the pipeline.
- **Form 677-1** for pipe and coating condition discovered during bellhole inspections.

APPENDIX A: CROSS REFERENCE TABLE

ILI Procedure		Reference Document						
Section	Description	ASME B31.8S	49 CFR	API 1163	ASNT ILI-PQ	NACE 35100	NACE SP0102	NACE 05164
1.0	Purpose							
2.0	Introduction					Introduction		
3.0	Code Reference and Standards			1.2				
4.0	Policy and Scope							
4.2	Scope	1.1	192.901	2				
5.0	Responsibility and Qualifications							
5.2	Qualifications		192, Subpart N	5.2	6.0			
6.0	Definitions	13	192.903	4			2	
7.0	Pre-Assessment							
7.1	Scheduling and Planning the ILI Survey						6, 6.2	
7.1.1	Physical Pipeline Restrictions			6.3		Operational Issues	3.2, 4	
7.1.2	Launching and Receiving Facilities	6.2.5		6.3		Operational Issues	3.2, 4	
7.1.3	Operational Conditions			6.3		Operational Issues	3.2, 4	
7.1.4	Waste and Debris Collection			6.3		Operational Issues	3.2, 4, 6.2.5	
7.2	Data Gathering and Integration	4	192.917			Reviewing the Effectiveness of Corrosion Control	4.8	
7.3	High Consequence Area Identification	4	192.903					
7.4	Baseline and Reassessment Plan	2.3.4	192.921					
7.4.1	Pipeline Threats	2.2	192.919					
7.4.2	Integrity Assessment Methods	6	192.919	6.1				
7.4.3	Assessment Schedule		192.919					
7.5	Threat Identification	2.2	192.917					
7.5.1	Time Dependent Threats	2.2	192.917					
7.5.2	Static or Stable Threats	2.2	192.917					
7.5.3	Time Independent Threats	2.2	192.917					
7.5.4	Human Error	2.2						
7.5.5	Interactive Threats	2.2						
7.6	Risk Assessment	5	192.917			Risk Analysis-Based Considerations		
7.9	ILI Tool Selection	6.2		6.1			3	
7.9.1	ILI Tools for External & Internal Corrosion Threats	6.2.1						
7.9.2	ILI Tools for Stress Corrosion Cracking Threat	6.2.2						
7.9.3	ILI Tools for Third Party Damage Threat	6.2.3						
7.9.5	All Other Threats	6.2.4						
7.10	Pipeline Cleaning Requirements						4.7	
8.0	In-Line Inspection	6.2						
8.1	Minimum Technical Tool Requirements	6.2.5		6.5, 7.2			3.1	
8.2	Procurement of ILI Services						5	
8.3	ILI Tool Compatibility Assessment						4	

ILI Procedure		Reference Document						
Section	**Description**	**ASME B31.8S**	**49 CFR**	**API 1163**	**ASNT ILI-PQ**	**NACE 35100**	**NACE SP0102**	**NACE 05164**
8.3.1	Vendor Questionnaire	6.2.5					3.2.1.2.1 – 3.2.1.2.7	
8.3.2	ILI Tool Specifications			6.5				
8.4	Benchmarking and Tracking					Benchmarking: Preparing Aboveground Location	6.3	
8.4.1	Survey Control Points and Aboveground Markers			8.3.3, 8.4.3			6.3	
8.4.2	ILI Tool Tracking					Tool Tracking	6.3.6 – 6.3.8	
8.4.3	ILI Tool Transmitters						6.3.5	
8.5	Pre-Intelligent Tool Run Requirements			8.3				
8.5.1	Pre-ILI Meeting			8.3				
8.5.2	Pipeline Cleaning Run					Cleaning and Gauging		
8.5.3	Pipeline Geometry Evaluation					Cleaning and Gauging	4.6.3	
8.6	Intelligent Tool Run			8.4				
8.6.2	Pre-Calibration Function Test			8.3.1				
8.6.3	Mechanical Checks			8.3.2				
8.6.4	Launching and Receiving Procedures			8.4.1, 8.4.4				
8.7	Post Intelligent Tool Run Requirements			8.5		Post-Run Data Assessment		
8.7.1	Post-Calibration Function Test			8.5.1, 8.5.2				
8.7.2	Survey Acceptance Criteria						5.1.5	
8.8.3	Post-Run Operational Report						5.2	
9.0	ILI Data Analysis & Reporting Requirements						8	
9.1	Reporting Requirements			10			5.3, 5.4	
9.3	Response to Reported Indications	7						
9.3.1	Discovery of an Integrity Condition		192.933					
9.3.2	Immediate Response/Repair Conditions	7.2.1, 7.2.3	192.933					
9.3.3	Temporary Pressure Reduction	7.2.1	192.933					
9.3.4	Scheduled One-Year Conditions	7.2.3	192.933					
9.3.5	Monitored Conditions	7.2.3	192.933					
9.3.6	Other Scheduled Conditions	7.5	192.933					
9.3.7	Safety Related Conditions		191.23, 191.25					
9.3.9	Prioritization of Response Indications	7.2	192.933					
9.4	Selection of Dig Sites			9.2.4		Verification Dig & Selection of Sites	8.7	
10.0	Direct Examination							
10.3	Defect Assessment					Evaluation of Examined Defects		
10.4.1	Repair Methods	7.6						
10.7	Assessment of ILI Tool Performance			7.3				Assessing ILI Tool Performance
10.8	Probability of Exceedance			7.3				

ILI Procedure		Reference Document						
Section	**Description**	**ASME B31.8S**	**49 CFR**	**API 1163**	**ASNT ILI-PQ**	**NACE 35100**	**NACE SP0102**	**NACE 05164**
10.9	Corrosion Growth Rates						9.3	
11.0	Post Assessment							
11.2	Update ILI Vendor of Results			9.2.4			8.7.3	
11.4	Establishing Re-Assessment Intervals		192.939					
11.5	PI Performance Metrics	9						

APPENDIX B: PHMSA INSPECTION PROTOCOL TABLE

ILI Procedure		PHMSA Inspection Protocol Item		Year of Finding
Section	Name	Item	Description	
7.4	Baseline and Reassessment Plan	B.01	Verify that the operator's Baseline Assessment Plan (BAP) specifies an assessment method(s) for each covered segment that is best suited for identifying anomalies associated with specific threats identified for the segment	2012
7.4.3	Assessment Schedule	B.02	Verify that the BAP contains a schedule for completing the assessment activities for all covered segments; and that the BAP appropriately considered the applicable risk factors in the prioritization of the schedule	2012
7.5	Threat Identification	C.01	Verify that the operator identifies and evaluates all potential threats to each covered pipeline segment	2012
7.2	Data Gathering and Integration	C.02	Verify that the operator gathers and integrates existing data and information on the entire pipeline that could be relevant to covered segments, and verify that the necessary pipeline data have been assembled and integrated	2012
7.6.3	Verifying the RFM Data	C.04	Verify that the integrity management program identifies and documents a process to validate the results of the risk assessments	2012
9.3	Response to Reported Indications	E.01	Verify that provisions exist to discover and evaluate all anomalous conditions resulting from integrity assessment and remediate those which could reduce a pipeline's integrity	2012
9.3	Response to Reported Indications	E.02	Inspect the operator's program to verify that provisions exist for the classification and remediation of anomalies that meet the criteria for: (1) Immediate repair conditions; (2) One-year conditions; (3) Monitored conditions; or (4) Other conditions as specified in ASME B31.8S-2004, §7	2012
7.2 & 7.8.1	Data Gathering and Integration/Previous ILI Surveys	E.04	Inspect operator repair and remediation records to verify that remediation activities have been conducted in accordance with program requirements	2012
11.3	Establishing Re-Assessment Intervals	F.04	Verify that the requirements for establishing the reassessment intervals are consistent with 49 CFR 192.939 and ASME B31.8S-2010. [49 CFR 192.937(a), 192.939(a), 192.939(b), 192.913(c), and ASME B31.8S-2010, §5, Table 3]	2012
9.3	Response to Reported Indications	H.06	Verify that the operator takes required actions to address corrosion threats	2012

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: Version 2.5. CPUC believed the language in §9.3.1 was ambiguous. They requested the language regarding the timeframe when discovery of a potential condition is made match that of PHMSA FAQ 34. Removed §§7.2.3 and 7.3.2 and Figure 4 because the content was obsolete. Revised §9.4.10 to identify the file an Integrity Engineer must utilize to document selection of direct examinations.

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Part of SoCalGas O&M Plan:	No
Part of SDG&E O&M Plan:	No
Last O&M Review date:	
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Part of Non-O&M Parts 191-193 Plan	Yes
Non-O&M 49 CFR Codes & Impacted Sections of Document	192.921: (a)(1)7.9 192.933(b): 9.3.1 192.933(c): 9.3.6 192.937: (c)(1) 7.9
Part of Distribution IMP (DIMP)	No
Part of Transmission IMP (TIMP)	Yes
Impacts GO112E	No
GO112E Codes & Impacted Sections of Document	
Impacts GO58A	No
GO58A Codes & Impacted Sections of Document	
Impacts GO58B	No
GO58B Codes & Impacted Sections of Document	
Indices/Binders in Which Document is Filed:	TIMP2
NOP Learning Module (LM) Training Code:	NOP00186

Company Operations Standard
Gas Standard
Pipeline Integrity

Bellhole Inspection Requirements	SCG:	167.0211

PURPOSE **To provide requirements and guidelines for conducting a bellhole inspection on DOT defined transmission pipelines that meet requirements of 49 CFR 192, Subpart O.**

1. POLICY AND SCOPE

1.1. This standard is applicable to all bellhole inspections conducted as part of the Transmission Integrity Management Program (TIMP). The bellhole inspection process examines the coating, pipe and environment of the exposed pipeline segment through the use of nondestructive examination (NDE) and other testing techniques. Observations are documented and the data is used to evaluate the integrity of the exposed pipeline segment, perform root cause analysis and verify pipe segment attributes within the High Pressure Pipeline Database (HPPD).

1.2. This standard describes the roles and responsibilities of all personnel involved during the bellhole inspection process and identifies qualifications, data collection and documentation requirements.

1.3. The bellhole inspection report, photographs and supplemental data (e.g. corrosion grids) generated during the bellhole inspection shall be submitted within twenty-four (24) hours of completing the pipe examination. When additional NDE is requested, the vendor's report documenting the results shall be submitted within twenty-four (24) hours of completion of the NDE method.

1.4. This document shall be controlled and reviewed per the requirements contained within **Manual TIMP.14** and **Manual TIMP.15**.

2. ROLES AND RESPONSIBILITIES

2.1. **Pipeline Integrity Construction and Inspection Project Manager (CIPM)** is responsible for providing access to the pipeline for coating and pipe examination by authorized personnel and coordinates required pressure reductions and/or remediation in accordance with Company procedures.

2.2. **Pipeline Integrity Engineering Project Manager (EPM)** is responsible for managing all aspects of an integrity assessment, facilitates the exchange of bellhole inspection documentation and communicates technical evaluation results and remediation recommendations to the CIPM.

2.3. **Integrity Engineer (IE)** is responsible for analyzing data collected during the bellhole inspection process, ensures bellhole inspection data is complete and accurate (quality assurance) and determines remediation recommendations.

2.4. **Inspection Personnel (IP)** is responsible for performing coating, pipe and environment examinations of the exposed pipeline segment and documenting the data specified within this standard in accordance with Company approved procedures. IP shall adhere to all requirements contained herein and request approval from the EPM prior to performing any procedural deviation.

2.5. **Data Management & GPS (DMG) Group** is responsible for conducting annual GPS training and the development, maintenance, deployment and support of the Company's "Bellhole Inspection Software"; which is used by the IP to document the requirements specified within this standard.

3. QUALIFICATIONS

3.1. The provisions of this procedure shall be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of defect assessment on ferrous piping systems. Table 1 lists the minimum qualifications for roles specified in this procedure in accordance with **Manual TIMP.15**.

Table 1: TIMP Minimum Qualification Requirements

Requirements	IE	CIPM	IP
Bellhole Inspection Requirements Training	X		X
RSTRENG/KAPA Training	X		
ASNT Level 1 UT & MPI			X
Operator Qualification		X	X
GPS Training (Annual)			X

4. DEFINITIONS

4.1. **Anomaly:** Refer to Manual TIMP.A, *Terms, Definitions and Acronyms*.

4.2. **Bellhole:** Refer to **TIMP.A**.

4.3. **Cathodic Protection (CP):** Refer to **TIMP.A**.

4.4. **Corrosion**:

4.4.1. *General corrosion:* A corrosion attack that proceeds uniformly over the exposed surface without any appreciable localization of attack.

4.4.2. *Localized corrosion*: A corrosion attack that occurs at discrete sites.

4.4.3. *Pitting*: A deep narrow corrosive attack, which often causes rapid penetration of the substrate.

4.5. **Examination:** Refer to **TIMP.A**.

4.6. **External Corrosion Direct Assessment (ECDA):** Refer to **TIMP.A**.

4.7. **Internal Corrosion Direct Assessment (ICDA):** Refer to **TIMP.A**.

4.8. **Inline Inspection (ILI):** Refer to **TIMP.A**.

4.9. **Inspection:** Refer to **TIMP.A**.

4.10. **Nondestructive Examination (NDE):** Refer to **TIMP.A**.

4.11. **Magnetic Particle Inspection (MPI):** A nondestructive inspection technique for locating surface cracks in a steel using fine magnetic particles and a magnetic field.

4.12. **Microbiologically Influenced Corrosion (MIC):** Refer to **TIMP.A**.

4.13. **Pipe-to-Electrolyte (P/E) Potential:** Pipe-to-electrolyte potential may also be referred to as structure-to-electrolyte or pipe-to-soil (P/S) potential. See "*Structure-to-Electrolyte Potential*" in §2.7 (Definitions) of **Gas Standard 169.0209**.

4.14. **Pressure Test (PT):** Refer to **TIMP.A**.

4.15. **Stress Corrosion Cracking (SCC):** Refer to **TIMP.A**.

4.16. **Scab:** A fold of metal that has been rolled or otherwise worked against the surface of the rolled metal, but has not fused into sound metal.

4.17. **Scale:** An imperfection in the form of a shell or veneer, generally attached to the surface by sound metal. Usually has its origins in an ingot defect when an air pocket or inclusion was rolled out and became surface breaking.

4.18. **Sleeve – Type A:** Pressure reinforcement sleeve that is installed without welding to the pipe. This type of sleeve cannot be used for repairs on leaking defects.

4.19. **Sleeve – Type B:** Pressure containment sleeve that is welded onto the pipe using fillet welds at the ends. This type of sleeve is used to repair leaking defects and circumferential-oriented defects.

4.20. **Sleeve – Composite:** Pressure reinforcement sleeve (similar to Type A) that uses high strength composite materials that are wrapped or coiled around the pipe.

4.21. **Sliver:** A thin elongated piece of metal typically attached to the pipe at one end. Slivers are caused by an air pocket or inclusion in the molten steel being rolled out in one direction.

4.22. **Stingers:** Lines mostly parallel to the direction of rolling that are caused by foreign material in the molten steel being rolled out.

5. INSTRUMENTATION

5.1. A handheld computer with Global Navigation Satellite System (GNSS) capabilities shall be used to record coating, pipe and environment data and collect GPS data in accordance with the specifications contained within Table 1 of **Gas Standard 167.0245**.

5.1.1. Equipment shall be loaded with the latest version of the Company's "Bellhole Inspection Software".

5.1.2. The current version of the GPS manufacturer software, firmware, and mobile operating system shall be maintained and used to ensure optimum performance.

6. SAFETY

6.1. When bellhole inspections are performed by Company personnel, it shall be done in accordance with the **Manual IIPP.1** and **Gas Standard 166.0080**.

6.2. When bellhole inspections are performed by a contractor, it shall be done in accordance with **Safety Standard 167.04**.

7. EXCAVATION REQUIREMENTS

7.1. The pipe shall be excavated in accordance with **Gas Standard 184.0175** and **Gas Standard 223.0140**.

7.2. The CIPM shall identify the appropriate environmental procedures to use depending upon the nature of the work being performed. Additional guidance is available in **Manual TIMP.11**.

7.3. The minimum length of coating and pipe that shall be examined during an integrity assessment is fifteen (15) feet. For locations where no indications are detected during an integrity assessment or for other TIMP-related activities (e.g. RFR sample collection or P&M excavations), the EPM or IE may reduce the length to ten (10) feet.

7.4. Excavations shall be extended in length when:

7.4.1. The original indication may be contained in the portion of the pipeline buried beyond the boundaries of the excavation;

7.4.2. To examine an anomaly that has not been completely exposed; or

7.4.3. A girth weld is required for establishing a reference for axial measurements.

The CIPM or IP shall contact the EPM to determine when expansion of the excavation is necessary.

8. REFERENCE REQUIREMENTS

8.1. The reference location for all axial measurements during the coating and pipe examinations is dependent upon the assessment method or activity. The IP must establish the reference prior to performing the coating and pipe examinations.

8.1.1. When conducting Direct Assessment (DA), Pressure Test or other TIMP-related activities, the center of the excavation or an exposed girth weld should be the point of zero ("0") reference.

8.1.2. When conducting ILI, the most upstream girth weld within the excavation should be the point of "0" reference.

8.2. The reference location for determining orientation (clock position) is the top-dead center (TDC) of the exposed pipe (also referred to as the 12:00 position).

8.3. Chalk, pencil or paint markers shall be used for marking out the coating and pipe prior to conducting the coating and pipe examinations.

8.3.1. Use colors that contrast the surface being examined and that allow markings to be read in photographs.

8.3.2. All markings must be written legibly on the coating or pipe.

8.4. Measure and mark one (1) foot increments from the "0" reference in both the upstream and downstream directions along the exposed pipe.

8.4.1. Label each increment with the appropriate distance (in feet) from the axial reference location at the 2:00, 6:00 and 10:00 positions.

8.4.2. Flow shall be indicated with a negative (-) sign for upstream values and a positive (+) sign or no sign for downstream values.

9. NAMING REQUIREMENTS

9.1. When conducting ILI, the identification of girth welds, longitudinal seams and pipe anomalies may be predetermined within the bellhole inspection report. Anomalies and pipe characteristics that do not have a predetermined name shall be identified in accordance with this section.

9.2. Longitudinal seams and girth welds shall be labeled using an identifier that contains either LS (for longitudinal seam) or GW (for girth weld), followed by a dash (-) and number.

9.3. Coating and pipe anomalies shall be labeled with an identifier that contains the anomaly type (abbreviated), followed by a dash (-) and number. The abbreviations to be used for the identifier (with examples) are listed Table 2.

9.4. Previous repairs shall be labeled with an identifier that contains the repair type (abbreviated), followed by a dash (-) and number. The abbreviations to be used for the identifier (with examples) are listed Table 3.

9.5. The minimum number of digits for the numerical portion of the identifier shall be two (2) and each type of pipe anomaly, repair, longitudinal seam or girth weld should be numbered in sequential order beginning upstream and heading in the downstream direction.

Table 2

Coating Anomaly Type	Abbreviation	Example
Holiday	H	H-01
Disbondment	DIS	DIS-08
Blister	BL	BL-05
Pipe Anomaly Type	**Abbreviation**	**Example**
Arc Strike	AS	AS-77
Bulge	BG	BG-07
Crack	CR	CR-22
Dent w/ Corrosion	DC	DC-03
Dent w/ Cracking	DCR	DCR-14
Dent w/ Gouge	DG	DG-07
External Corrosion	EC	EC-15
Gouge	G	G-06
Internal Wall Loss	IA	IA-33
Lamination	LAM	LAM-04
Linear Indication	LI	LI-13
Plain Dent	PD	PD-09
Scab	SB	SB-12
Scale	SE	SE-03
Sliver	SL	SL-04
Stingers	ST	ST-01
Stress Corrosion Cracking	SCC	SCC-01
Wrinkle Bend	WB	WB-01

Table 3

Repair Type	Abbreviation	Example
Grind Repair	GR	GR-08
Mechanical Clamp	MC	MC-33
Puddle Weld	PW	PW-05
Sleeve – Type A	SLA	SLA-09
Sleeve – Type B	SLB	SLB-02
Sleeve – Composite	SLC	SLC-01

10. PHOTOGRAPH REQUIREMENTS

10.1. The coating and pipe shall be marked in accordance with §8 of this standard prior to taking photographs.

10.2. Photographs taken during the bellhole inspection shall be in an electronic format. Each photograph shall contain the following general information on an arrow board pointing in the direction of flow (downstream) as established in §8.4.2 of this standard:

10.2.1. Pipeline name;

10.2.2. Excavation identifier (i.e. dig name);

10.2.3. Inspection date;

10.2.4. Name of IP;

10.2.5. Description of object being photographed (e.g. H-01, EC-23 or 3:00 position of exposed pipe);

10.3. IP shall take photographs of the following:

10.3.1. The environment (topography) upstream and downstream of the excavation;

10.3.2. Coating anomalies;

10.3.3. An overall view from aboveground of the coating after coating examination, but prior to coating removal;

10.3.4. Pipe anomalies (before and after MPI);

10.3.5. Welds and longitudinal seams (before and after MPI);

10.3.6. An overall view from aboveground of the pipe after pipe examination, but prior to any form of remediation; and

10.3.7. Local low spot (e.g., sag, drop section, etc.).

10.4. IP shall take close-up, far and overall view photographs of each coating and pipe anomaly discovered during the bellhole inspection. A scale/ruler must be included in each photograph (in units of inches) and the anomaly dimensions shall be written on an arrow board, the coating or the pipe.

10.5. The file name of each photograph shall contain the pipeline name (as it appears in the HPPD), the excavation ID, the assessment ID (as it appears on the ACF), the descriptor and the picture number.

10.5.1. File renaming shall be performed by the IE.

10.5.2. The file name may not contain any spaces and each aspect of the file name shall be separated by a carrot (^) such that the file name appears as follows: *PipelineName^ExcavationID^AssessmentID^Descriptor^###.FileExtension*" (e.g. "33-120^S2R3D11^RA-2012^EC-01^001.JPG"

10.5.3. The descriptor shall contain one of the following identifiers:

10.5.3.1. Coating anomaly identifier (e.g. DIS-01);

10.5.3.2. Pipe anomaly identifier (e.g. EC-03)

10.5.3.3. Longitudinal seam identifier (e.g. LS-01);

10.5.3.4. Girth weld identifier (e.g. GW-03);

10.5.3.5. The word "PIPE" (all letters uppercase) for photographs taken during the pipe examination that provide an overall view of the pipe and not intended to show the detail of an anomaly;

10.5.3.6. The word "COAT" (all letters uppercase) for photographs taken during the coating examination that provide an overall view of the coating condition and not intended to show the detail of an anomaly; or

10.5.3.7. "OV" (all letters uppercase) for photographs that show the environment upstream and downstream of the excavation.

10.5.4. The picture number should begin with "001" and continue sequentially for all file names with the same descriptor. Reset the picture number when the descriptor is unique.

10.5.5. For photograph containing multiple anomalies and/or features, the descriptor should contain commas (,) to separate each identifier (e.g. GW-01, LS-01), a dash (-) to show a group/range for the same identifier (e.g. DIS-01-10) or both (e.g. EC-01-03, G-03).

11. DATA REQUIREMENTS

11.1. Pipeline Segment Identification

11.1.1. The IE shall obtain and provide the IP with the following information:

11.1.1.1. Pipeline name;

11.1.1.2. Excavation identifier (i.e. dig name);

11.1.1.3. HCA segment (if applicable) and class location for the pipe being inspected;

11.1.1.4. Inspection category (ECDA, ICDA, ILI, P&M, PT, RFR, or Subpart M);

11.1.1.5. Name of the EPM and IE responsible for the assessment of the pipeline;

11.1.1.6. Pipe grade, diameter, nominal wall thickness (NWT), year of installation, manufacturer (if available), MAOP and MOP;

11.1.1.7. ECDA horizontal station, odometer readout from the ILI for the proposed inspection site or pipeline mile post; and

11.1.1.8. Reason for excavation.

11.1.2. The IP shall record the date the bellhole inspection began, their first and last name and their company's name.

11.2. Coating Examination

11.2.1. The axial location of coating anomalies shall be measured from the point of "0" reference to the center of the anomaly. Measurements shall be recorded in units of inches and taken to the nearest 0.01 inch or 1/64 inch.

11.2.2. The orientation of coating anomalies shall be measured from TDC (in the clockwise direction facing downstream) to the center of the anomaly. Length and width measurements shall be recorded in units of inches and taken to the nearest 0.01 inch or 1/64 inch.

11.2.3. The coating holiday detector shall be used in accordance with manufacturer instructions.

11.2.4. The following items shall be recorded by the IP:

11.2.4.1. Pipe coating type and condition;

11.2.4.2. Field coating type and condition (if applicable);

11.2.4.3. Dimensions of coating holidays (excluding those made during the excavation process or to calibrate the holiday detector), disbondment and blisters; and

11.2.4.4. Indicate if liquids were present under coating, whether a sample of liquid was collected and, the pH of liquids under the coating (if available).

11.2.5. The IP should also provide additional information that is pertinent to the examination. Examples include, but are not limited to:

11.2.5.1. Manufacturer, model and serial number of the holiday detector;

11.2.5.2. Voltage settings used for holiday detection;

11.2.5.3. Assessment of coating adhesion (sagging or hollow locations in coating);

11.2.5.4. Measurement of coating thickness;

11.2.5.5. Observations of brittleness;

11.2.5.6. Reasons use of the holiday detector was not possible;

11.2.5.7. Calcareous deposit details;

11.2.5.8. Descriptions of the nature of the holiday (i.e. natural or excavation caused); and

11.2.5.9. Mentioning disbondment was significant on the coating and therefore the labeling of the individual anomalies was not performed

11.2.6. After the coating examination has been completed, coating residue and corrosion deposits shall be removed to optimize the effectiveness of the pipe examination. The steel pipe surface must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products and coating remnants.

11.2.6.1. Coating removal is not required on factory-applied fusion bonded epoxy (FBE) coated pipeline segments where crack-like flaws are not suspected.

11.3. Pipe Examination – Characteristics

11.3.1. The axial location of girth welds, miter welds, wrinkle bends, fittings (e.g. fabricated branches, tees, reducers and elbows), wall thickness measurements and previous repairs shall be measured from the point of "0" reference to the center of the pipe characteristic or wall thickness measurement location. Measurements shall be recorded in units of inches and taken to the nearest 0.01 inch or 1/64 inch.

11.3.2. The orientation of longitudinal seams, wrinkle bends, fabricated branches, and previous repairs shall be measured from TDC (in the clockwise direction facing downstream) to the center of the anomaly.

11.3.3. The length, width and height measurements for wrinkle bends shall be recorded in units of inches and taken to the nearest 0.01 inch or 1/64 inch.

11.3.3.1. The height of a wrinkle bend shall be measured from peak to valley.

11.3.3.2. When multiple wrinkle bends are present, the spacing shall be measured from one wrinkle peak to the next downstream wrinkle peak, beginning with the most upstream wrinkle bend.

11.3.4. One (1) set of wall thickness measurements shall be performed 1-inch upstream and downstream of a girth or miter weld, at the "0" reference location (that is not a girth weld), local low spots (e.g., sag, drop section, etc.) and tees. Measurements shall be recorded in units of inches and taken to the nearest 0.001 inch.

11.3.4.1. A set consists of measurements taken at the 12:00, 3:00, 6:00 and 9:00 positions and near the longitudinal seam.

11.3.4.1. At a local low spot, one (1) set of measurements shall be taken at the lowest point and two (2) sets of measurements upstream and downstream of the lowest point (5 sets total). Measurements shall be spaced 1-foot apart.

11.3.4.2. At the discretion of the integrity engineer, B-Scan or an equivalent method may be performed to measure wall thickness from the 3:00 to the 9:00 position.

11.3.5. The following items shall be recorded by the IP:

11.3.5.1. Girth weld type, joint design (if possible) and axial location;

11.3.5.2. Longitudinal seam type, orientation and seam height (if applicable);

11.3.5.3. Dimensions of wrinkle bends, bend angle formed by the wrinkle(s) and spacing (if multiple wrinkles are present);

11.3.5.4. Pipe temperature (°F);

11.3.5.5. Pipeline circumference (units of inches);

11.3.5.6. Angle of inclination in the direction of flow;

11.3.5.7. Wall thickness measurements;

11.3.5.8. Evidence of recent excavation or recent third-party damage (TPD) and previous repair locations; and

11.3.5.9. Grade, manufacturer, class/rating and size of fabricated branches and tees.

11.3.6. The IP should also provide additional information that is pertinent to the examination. Examples include, but are not limited to:

11.3.6.1. The longitudinal seam was not visible or could not be identified; and

11.3.6.2. Damage caused by the excavation crew.

11.4. Pipe Examination – Anomalies

11.4.1. The axial location of pipe anomalies shall be measured from the point of "0" reference to the center of the anomaly. Measurements shall be recorded in units of inches and taken to the nearest 0.01 inch or 1/64 inch.

11.4.2. The orientation of pipe anomalies shall be measured from TDC (in the clockwise direction facing downstream) to the center of the anomaly.

11.4.3. Length and width measurements for pipe anomalies shall be recorded in units of inches and taken to the nearest 0.01 inch or 1/64 inch.

11.4.3.1. Length and width of corrosion anomalies shall be established in accordance with **Gas Standard 182.0050**.

11.4.4. The maximum depth measurement for metal loss, cracking or a stress riser shall be recorded in units of inches and taken to the nearest 0.001 inch.

11.4.4.1. When metal loss, cracking or a stress riser interact with a dent, the maximum deflection of the dent (Dimension "C" in Detail A of Figure 1) and the maximum depth of the metal loss or stress riser below the surface of the dent (Dimension "D" in Detail A of Figure 1) shall be measured.

11.4.4.2. The wall thickness near each metal loss anomaly shall be measured and recorded in units of inches and taken to the nearest 0.001 inch.

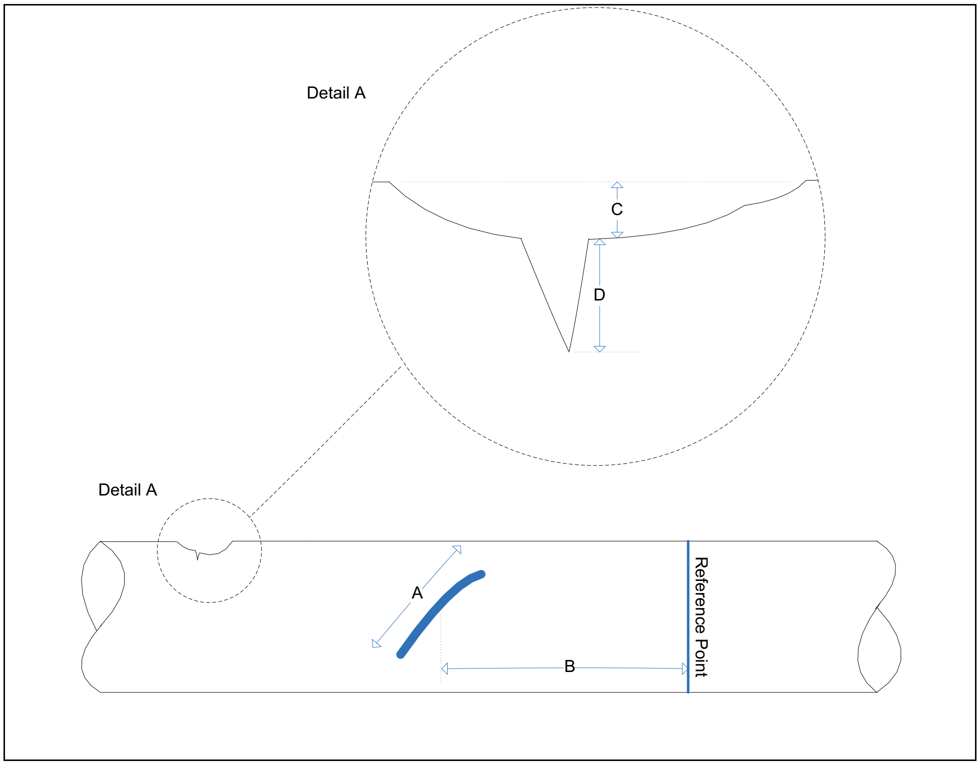

Figure 1: Mechanical damage data collection schematic

11.4.5. The following items shall be recorded by the IP:

11.4.5.1. Dimensions and description of external corrosion anomalies (refer to §12 of this standard for guidelines on corrosion grids);

11.4.5.2. Dimensions of all internal wall loss anomalies, mechanical damage (e.g. dent, gouge) and linear indications; and

11.4.5.3. Wall thickness near pipe anomalies.

11.4.6. The IP should also provide additional information that is pertinent to the examination. Examples include, but are not limited to:

11.4.6.1. Distribution of corrosion around the pipe circumference;

11.4.6.2. Corrosion following the pattern of tape wrap;

11.4.6.3. Corrosion associated only with field-applied coatings;

11.4.6.4. Corrosion present before installation (refurbished pipe);

11.4.6.5. Results of MIC testing (when performed);

11.4.6.6. Mechanical damage caused during the excavation;

11.4.6.7. Interaction of external corrosion with mechanical damage, other anomalies or pipe characteristics (e.g. – welds or mechanical damage); and

11.4.6.8. The type of dent (e.g.-smooth), interaction with other anomalies, constrained or unconstrained, etc.

11.5. Pipe Examination – NDE

11.5.1. Wet MPI or wet fluorescent MPI shall be performed on all welds, longitudinal seams, pipe anomalies and wrinkle bends.

11.5.1.1. MPI is not required on factory-applied FBE coated pipeline segments where crack-like flaws are not suspected.

11.5.1.2. If field conditions are not conducive, dry MPI may be used if approved by a Company representative prior to pipe examination.

11.5.1.3. In the absence of pipe anomalies, MPI shall be conducted on a random two (2) foot section of pipe located at the bottom third of the pipe.

11.5.2. The IE may utilize additional NDE methods to support engineering analysis. Examples include, but are not limited to: ultrasonic testing (e.g. guided or shear wave, phased array and Time-of-Flight Diffraction) and radiography.

11.5.3. NDE instruments shall be used in accordance with manufacturer instructions.

11.5.4. The following items shall be recorded by the IP:

11.5.4.1. Methods of NDE used to evaluate longitudinal seams, girth welds or parent metal and results; and

11.5.4.2. Manufacturer, model number and serial number of NDE tools.

11.5.5. The IP should also provide additional information that is pertinent to the examination. Examples include, but are not limited to:

11.5.5.1. The longitudinal seam was not visible or could not be identified;

11.5.5.2. No anomalies were discovered and therefore MPI was performed as described in §11.5.1.3 (specify axial location range MPI was performed); and

11.5.5.3. Information regarding why NDE was performed (e.g. shear wave was requested due to crack like indications).

11.6. Cathodic Protection

11.6.1. Pipe-to-electrolyte (P/E) potentials shall be measured using a calibrated copper-copper sulfate ($Cu\text{-}CuSO_4$) field reference electrode. Measurements shall be recorded in units of volts (DC) and taken to the nearest 0.001 volts.

11.6.2. Soil resistivity shall be obtained using a soil resistance meter in combination with a soil box and recorded in units of ohm-centimeters (Ω-cm).

11.6.3. The following items shall be recorded by the IP:

11.6.3.1. The P/E potentials at grade level (below the pavement), 12:00 and 6:00 positions (at the soil and pipe interface within the excavation); and

11.6.3.2. Dry and saturated (wet) soil resistivity for the native and backfill soils.

11.6.4. The IP should also provide additional information that is pertinent. Examples include, but are not limited to:

11.6.4.1. Additional soil resistivity values obtained;

11.6.4.2. AC voltage measurement; and

11.6.4.3. Another appurtenance was shorting the CP.

11.7. Location

11.7.1. The following items shall be recorded by the IP:

11.7.1.1. GPS coordinates of the bellhole reference with a fix quality of "DGPS Fix"; and

11.7.1.2. The length of coating and pipe examined (in units of feet).

11.7.2. The IP should also provide additional information that is pertinent. Examples include, but are not limited to:

11.7.2.1. Landmarks, street address or intersection where excavation is located

11.8. Environment

11.8.1. The depth of cover shall be measured from the surface to TDC of the exposed pipe and recorded in units of inches.

11.8.2. The following items shall be recorded by the IP:

11.8.2.1. Predominant land use at the site of the excavation;

11.8.2.2. Topography in the immediate area of the excavation including flat, hillside, toe of slope and water crossing;

11.8.2.3. The type of cover located above the pipe;

11.8.2.4. Depth of cover;

11.8.2.5. Quality of backfill soil;

11.8.2.6. Native soil type;

11.8.2.7. Moisture content of native soil;

11.8.2.8. Whether soil samples were taken; and

11.8.2.9. Presence of ground water, whether a sample was collected and the pH of the ground water (if available).

11.8.3. The IP should also provide additional information that is pertinent to the environment. Examples include, but are not limited to:

11.8.3.1. Observations of excessive rubbish and construction debris in the backfill;

11.8.3.2. Pipeline crossings at or near the excavation;

11.8.3.3. Evidence of ground movement or severe erosion; and

11.8.3.4. Surrounding tree roots.

11.9. Additional information should be populated with notes from the inspection that would be useful for engineering analysis or any deviation from standard procedure.

11.10. IP shall document the date on which all field activities related to the inspection were completed (not including repair activities).

12. CORROSION GRIDS

12.1. At the discretion of the IE, construction of a corrosion grid may be required to complete accurate depth measurements for remaining strength analysis or ILI "pit matching". Guidelines for the grid are listed below:

12.1.1. Neatly record the data on a separate sheet of paper. Transfer the data into an electronic format (i.e. spreadsheet) after the measurements are taken.

12.1.2. Ensure the corrosion grid corresponds to the correct corrosion anomaly identified in bellhole inspection report.

12.1.3. Use numbers for the column labels. The numbers for the labels should increase linearly in the pipeline axial direction.

12.1.4. Use letters of the alphabet for the row labels; which correspond to the circumferential spacing.

12.1.5. Standard grid resolution should be 1-inch increments. Use good judgment when deviating from the standard resolution to a finer or coarser grid.

13. SOIL SAMPLE COLLECTION

13.1. The IP shall collect one (1) sample of "Backfill" soil from the upstream or downstream bank wall in close proximity to the exposed pipeline

13.1.1. The area from which the soil sample is taken shall not exceed a distance of one-half (½) the pipe diameter from any location along the surface of exposed pipe.

13.2. Samples shall be collected in a well-built container capable of enclosing a volume of approximately 1 gallon. The container should have all the air removed and sealed tightly. If using plastic bags, double bag the samples. The sample should be as close to the original state as possible when collected and delivered.

13.2.1. All sample collection tools (bucket, shovel, etc.) shall be rinsed with clean water and dried thoroughly before sample collection at each bellhole to prevent contamination.

13.2.2. Minimize sample exposure to direct sunlight and elevated temperatures.

13.3. The IP shall deliver the samples with a completed Chain-of-Custody form to the appropriate analysis vendor. The soil containers shall be labeled with the following details:

13.3.1. Utility (SoCalGas or SDG&E);

13.3.2. Name of IP who collected the sample;

13.3.3. Pipeline name;

13.3.4. Dig number;

13.3.5. Date, time and temperature.

14. OPERATOR QUALIFICATION COVERED TASKS
(See **167.0100**, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 2.1.** – 49 CFR 192.459 – Examining buried pipeline when exposed.
- **Task 2.12.** – 49 CFR 192.477 – Regular monitoring for internal corrosion.
- **Task 2.14.** – 49 CFR 192.485 – Recognizing general and localized corrosion, taking action: Transmission
- **Task 2.15**. – 49 CFR 192.487 – Recognizing general and localized corrosion, taking action: Distribution
- **Task 5.2.** – 49 CFR 192.614(c)(6) – Inspection and standby for prevention of damage to pipelines

15. RECORDS

15.1. IP shall submit the completed report (i.e. text files exported from "Bellhole Inspection Software"), photographs and supporting documentation (e.g. corrosion grids) to the EPM by e-mail or through the Company's Electronic Data Transfer website (https://edt.sempra.com).

15.2. Physical changes to the pipeline shall be documented and routed by the CIPM in accordance with **Form 2112**.

15.3. Pipe and coating condition discovered during bellhole inspections shall be documented and routed by the CIPM in accordance with **Form 677-1**.

15.4. The record retention period shall be LOA+5 (life of the asset plus five years) in accordance with the SoCalGas Retention Schedule.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
Brief: The following items were revised in response to suggested process improvements: §2.1 - Changed title of "Pipeline Integrity Transmission O&M Project Manager" to "Pipeline Integrity Construction and Inspection Project Manager". Changed acronym from "O&M PM" to "CIPM" throughout document. §2.2 - Changed acronym for Pipeline Integrity Engineering Project Manager from "PM" to "EPM" throughout document. §2.4 - Added statement that requires IP to seek approval from EPM prior to performing procedural deviations. Table 1 - Modified Table 1. Removed PM field and added OpQual requirement for CIPM. §5.1.1 - Changed name of "Bellhole Inspection Program" to Bellhole Inspection Software". Changes also made throughout entire document. §11.2.6.1 - Revised statement to not require coating removal on factory-applied FBE coated pipeline segments where crack-like flaws are not suspected. §11.5.1 - Revised statement to not require MPI on factory-applied FBE coated pipeline segments where crack-like flaws are not suspected. §11.7.1.1- Section revised to specify fix quality for GPS coordinates based on Ralph and Gerri's observations. §14 - Added OpQual Task 5.2 based on CA Govenrment Code §4216.

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PURPOSE **Provide a scope of work and consistent specifications for contractors of Sempra Energy that provide services in support of in-line inspection (ILI), analysis, and reporting of pipeline systems.**

1. POLICY AND SCOPE

1.1. This document has been identified as part of the Integrity Management Program and is subject to the Program's Quality Assurance Plan. This document shall be controlled per the guidelines established within the Program's Quality Assurance Plan. The Integrity Management Program applies to Transmission lines within high consequence areas (HCA) as defined by the Code of Federal Regulations (Title 49 Part 192).

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **ILI Contractor Responsibilities**

- **Tool Specification**

2.1.1. The following are minimum detection requirements for ILI inspection tool systems:

- Metal loss detection shall detect and size all volumetric wall loss anomalies of 10% wall thickness and greater.
- Deformation detection shall be capable of indicating and sizing dents of 2% diameter and greater.
- Systems shall be capable of indicating and locating dents with metal loss and dents impacting a long seam or girth weld.

2.1.2. Caliper Tool Minimum Requirements: A Caliper tool shall be provided when the ILI CONTRACTOR proposes a stand-alone combination MFL/Geometry tool as part of the ILI CONTRACTOR'S bid. The tool shall be selected by the ILI CONTRACTOR and be appropriate for the inspection of each pipeline project. As a minimum, the tool must be able to resolve the following:

- Deformation depths greater than 2% of the diameter of the pipeline
- The orientation of the deformation by o'clock positioning

- Significant bends (with angle and orientation noted), Example: 45 degree bend right
- Significant changes in pipe diameter or geometry (ovality, bulging, etc.); and, Identification of each girth weld

2.1.3. Geometry Tool Minimum Requirements: The tool shall be selected by the ILI CONTRACTOR and be appropriate for the inspection of each pipeline project. As a minimum, the tool must be able to resolve the following:

- Deformation depths greater than 2% of the diameter of the pipeline
- The orientation of the deformation by o'clock positioning
- The axial length and circumferential width
- Significant bends (with angle and orientation noted), Example: 45 degree bend right
- Significant changes in pipe diameter or geometry (ovality, bulging, etc.)
- Identification of each girth weld

2.1.4. Smart Tool Minimum Requirements: The tool shall be selected by the ILI CONTRACTOR and be appropriate for the inspection of each pipeline project. As a minimum, the tool must be able to resolve the following:

- Be used in conjunction with the geometry tool to indicate and locate dents impacting a long seam or girth weld.
- Be used in conjunction with the geometry tool to indicate and locate dents with metal loss.
- Identify wall loss greater than 10%
- Provide ID/OD discrimination
- Discriminate wall loss at girth welds and long seams

- Provide location of anomalies (i.e. axial, circumferential and orientation of indication or anomaly)
- Long seam detection and O'clock orientation

2.1.5. The ILI CONTRACTOR shall provide complete descriptive information including performance and dimensional specifications for the proposed tool(s). The information to be provided shall include but is not limited to the following:

- Inspection tool velocity range (minimum, maximum, and optimal) and description of impact on data resolution if inspection tool is operated outside of specified velocity range.
- Minimum flow and pressure specifications to successfully push the insertion tools (cleaning, geometry & Smart Tool).
- Confirmation that the pipeline is suitable for in-line inspection. Metal loss sensor sample rate.
- Inspection tool length and weight.
- Inspection tool sensor type (Hall Effect or Coil, Ultrasonic, Eddy Current, EMAT, other).
- Number, circumferential spacing, and redundancy of sensors.
- Location of offices where data analysis will be performed, including a single point of contact for technical support.
- Inspection tool tolerances for parameters including odometer data in relation to defect location, depth of metal loss, length of metal loss, and clock position (circumferential position) on the pipe. Specifications regarding the percentage of time the identified tolerances are met.
- AGM placement requirements.
- Tool bend radius and wall thickness specifications
- Inertial Mapping Unit (IMU) mapping and reporting capabilities Tool pipe size transition range.

2.1.6. The ILI CONTRACTOR shall assume that branch connections are unbarred unless otherwise specified. The ILI CONTRACTOR shall ensure that the inspection tool can successfully negotiate such branch connections without incurring damage or impacting the integrity of the survey.

2.1.7. Mainline block valves may have valve seat spaces that require spanning by the inspection tool. The ILI CONTRACTOR shall ensure that the inspection tool can successfully negotiate such spans without incurring damage or impacting the integrity of survey.

2.1.8. Mainline check valves shall not be pinned open during the inspection survey and the inspection tool is expected to negotiate such check valves without incurring damage or impacting the quality of the final results.

- **Field Activities**

2.1.9. The ILI CONTRACTOR shall confirm the tool's calibration and tool's overall condition with the COMPANY representative before and after run. The ILI CONTRACTOR will provide the COMPANY with a written report that describes the details of complying with the requirements of the latest version of API-1163 ILI Systems Qualification Standard concerning: Section 8.3 Pre-Inspection Requirements and Section 8.5 Post-Inspection Requirements. This written report describing pre-inspection and post-inspection tool condition will be included in the ILI CONTRACTOR'S comprehensive data summary and analysis Final Report which is sent to the COMPANY within 60 calendar days following the removal of the tool from the pipeline. The following summarizes the ILI CONTRACTOR'S Pre-Inspection and Post-Inspection requirements for this issue:

- Pre-Inspection Requirements: Pre-inspection requirements are defined as the activities that are to be completed before launching an ILI tool into the pipeline.

2.1.9..1. Functional Tests: The ILI CONTRACTOR shall define and document necessary steps to prepare and validate proper operation of the ILI tool prior to an inspection run. The steps shall include a function test to ensure the tool is operating properly. Pre-inspection function tests may include, but are not limited to:

2.1.9..1.1. Confirmation that an adequate power supply is available and operational.

2.1.9..1.2. Confirmation that all sensors, data storage, odometers, and other mechanical systems are operating properly.

2.1.9..1.3. Confirmation that adequate data storage is available.

2.1.9..1.4. Confirmation that all components of the inspection tool are properly initialized.

2.1.9..2. Mechanical Checks: Prior to an inspection run, the in-line inspection tool shall be checked visually to ensure that it is mechanically sound. The electronics shall be checked to make sure that they are properly sealed and functional.

2.1.9..3. Above Ground Markers: The ILI Contractor shall set the appropriate tool detection threshold on the above-ground markers to ensure proper detection.

- Post-Inspection Requirements: Post-inspection requirements cover activities that are to be completed, if required, on site after an inspection run has been completed and the inspection tool is retrieved from the pipeline. These activities are intended to validate that the in-line inspection tool has operated correctly during the inspection run.

2.1.9..1. Functional Tests: The ILI CONTRACTOR shall define and document steps necessary to validate the proper operation of the In-line inspection tool after an inspection run. These steps shall include a function test to ensure the tool has operated properly during the inspection. Deviations from these function checks shall be noted, and their effects shall be included in the inspection report sent to the COMPANY. Post-inspection function tests may include but are not limited to:

2.1.9..1.1. Tool cleanliness visual inspection.

2.1.9..1.2. Confirmation that adequate power was available and operational.

2.1.9..1.3. Confirmation that all sensors, data storage, odometers, and other mechanical systems operated properly.

2.1.9..1.4. Confirmation that adequate data storage was available.

2.1.9..1.5. Examination of tool for damage and significant wear.

2.1.9..2. Data Checks: The ILI CONTRACTOR shall define and document the steps necessary to check the quality and quantity of the data collected during the inspection run. Data checks are typically based on direct measurement data, data completeness, and data quality. Deviations shall be noted and their effects communicated to the COMPANY and included in the written report. These steps shall include but are not limited to:

2.1.9..2.1. Confirmation that a continuous stream of data was collected during the inspection.

2.1.9..2.2. Confirmation that the data meets basic quality requirements.

2.1.9..3. Direct Measurement Data: Direct measurement data may include information regarding system speed, operating temperature, operating pressure, and technology-specific data, such as magnetization levels for a magnetic flux leakage tool. Direct measurement data is typically used to make general judgments about the basic operation of an inspection tool during a run. Such data shall be utilized as one of the post-inspection data checks.

2.1.9..4. Data Completeness: The amount of data to be collected during an inspection is a function of line length and circumference. The amount of data collected allows an initial assessment of data completeness. The amount of data collected is typically accessible after processing the recorded data. Completeness of data shall be checked after the initial processing of the data. This will be considered one of the data checks.

2.1.9..5. Data Quality: Data quality can be demonstrated using a variety of data integrity checks, such as verification that the data taken was within the operating ranges of the sensors used. Such data checks shall be included in the data checking process. Post-inspection data quality checks do not cover the interpretation of the obtained data.

2.1.10. Pipeline Cleaning: The following summarizes the ILI CONTRACTOR'S responsibilities for this issue: The ILI CONTRACTOR shall provide the tools, equipment [ex. Pigs, air compressors etc.], and support [including multiple tracking/transmitter devices and personnel] necessary to adequately clean the pipeline to achieve successful geometry and smart tool inspections. As a minimum, the ILI CONTRACTOR'S cleaning program shall include the following progressive runs:

- All inspection and/or cleaning tools inserted into the pipeline shall be equipped with tracking devices.
- First run to include a 5 lb. foam squeegee pig or Disc pig. COMPANY representative shall determine which cleaning tool is best suited for the particular pipeline inspection.
- Two (2) runs with a construction style pig with brushes. ILI CONTRACTOR to have two (2) construction style pigs with brushes on site.
- Two (2) runs with a magnetic pig. ILI CONTRACTOR to have two (2) magnetic pigs on site.

- Final mechanical run to include a gauge plate sized to indicate a go or no-go determination for the geometry and MFL tools.

- If a combination MFL / Geometry tool is employed, ILI CONTRACTOR shall have available, a Caliper tool to indicate a go or no-go determination for the geometry / MFL tool. COMPANY representative shall determine if the Caliper tool is required for the particular pipeline inspection.

- The above description is a minimum and can be used for bidding purposes; additional runs may be required. If necessary, the COMPANY will provide a filter unit as part of the “Dry Cleaning” proposals. ILI CONTRACTOR will provide the specifications and requirements for any additional filter/separators proposed as part of the cleaning program. The COMPANY may choose not to use the ILI CONTRACTOR’S equipment.

2.1.11. The ILI CONTRACTOR shall provide a fully functioning in-line inspection tool (metal loss, geometry, bend, etc.) to be fully prepared for service and compatible with the pipe specifications and inspection parameters as detailed within the Feature Line Summary and elsewhere in the bid package.

2.1.12. The ILI CONTRACTOR shall supply an inspection tool that provides adequate battery life and storage capability to minimize the number of runs required with no impact on specified measurement tolerances.

2.1.13. The ILI CONTRACTOR shall provide benchmarking AGM device[s]. The number of each device shall be proposed as part of the bid or will be identified in the Request for Proposal. The COMPANY shall provide Above Ground Marker (AGM) locations and other intermediate Survey Control Points (SCPs) coincident with physical features, e.g., valves, taps, tees, ETSs, bends, girth welds on spans, etc., in a document identified as GPS Control Survey. The COMPANY shall perform any work that requires excavation and installation of devices on the pipeline.

2.1.14. Tracking of Inspection Tools: The following summarizes the ILI CONTRACTOR’S responsibilities for this issue:

- **All pigs will be equipped with tracking/transmitter devices.** Mounting hardware for transmitters will be constructed of robust material to withstand a rigorous environment.
- The ILI CONTRACTOR shall be responsible for providing insertion and extraction of all tool devices. The COMPANY will provide lifting.
- The TRACKING CONTRACTOR shall track all insertion tools launched into the pipeline, inclusive to the cleaning, geometry and smart tool inspection runs.
- The ILI CONTRACTOR shall provide support to TRACKING CONTRACTOR personnel and shall communicate the timing of the passage of all inserted tools as they pass established tracking points to a pre-established COMPANY Representative. This information will be used to assist COMPANY personnel in maintaining adequate speed control during the inspection runs.
- For bidding purposes, the ILI CONTRACTOR will NOT include in his price all costs associated with tracking the inspection tools throughout the pigging process.

2.1.15. Benchmark Placement: The following summarizes the ILI CONTRACTOR'S responsibilities for this issue:

- The ILI CONTRACTOR shall provide a minimum of (1) benchmarking unit per approximately every 1.2 miles to be placed periodically along the pipeline route representing Above Ground Markers (AGM). These units will be placed by the TRACKING CONTRACTOR exactly as specified by the COMPANY'S GPS Control Survey.
- The benchmarks units shall communicate with the ILI CONTRACTOR'S tooling in such a way as to be identifiable in the ILI CONTRACTOR'S inspection results, and utilized as linear identifiers to aid in locating anomalies.

2.1.16. The ILI CONTRACTOR shall provide, manage, and direct its team while conducting and performing in-line inspection services and provide a name and phone numbers for a single point of contact for field activities [i.e. superintendent or field lead]. The superintendent or field lead will coordinate all aspects of the ILI CONTRACTOR'S field activities and decision making regarding the acceptance of the pipeline's condition and the acceptability of the tool data.

2.1.17. The ILI CONTRACTOR shall provide all labor, supervision, per diem, materials, tools, vehicles, and inspection equipment to support field operations.

2.1.18. The ILI CONTRACTOR shall provide and transport the inspection and benchmarking equipment and ensure that they are in good operating condition.

2.1.19. The ILI CONTRACTOR shall provide sufficient pre and post calibration, programming and QC of the inspection tool to assure that performance specifications can be met.

2.1.20. The ILI CONTRACTOR will, prior to any instrument entering the piping system, demonstrate to a company representative the diameter of the tool and explain the specific performance. In the event of a dual diameter application, ILI CONTRACTOR will demonstrate to the COMPANY the action of the cups as they transition into and out of the pipelines diameter change.

- The ILI CONTRACTOR shall be responsible for the insertion and extraction of all tools entering the pipe system. The ILI CONTRACTOR is responsible for providing the personnel and any specialized equipment required for the insertion / extraction ILI tool process. The COMPANY will provide a crane or backhoe to support these activities.

- **Data Analysis for ILI**

2.1.21. 24 Hour Time Limit to Determine if Inspection is Successful: The following summarizes the ILI CONTRACTOR'S responsibilities for this issue:

  - The ILI CONTRACTOR shall declare to the COMPANY within 24 hours of the removal of any inspection tool, if a re-run is required due to problems such as tool malfunction or data quality issues. If a re-run is required, the COMPANY and the ILI CONTRACTOR shall schedule a re-run as soon as reasonably possible. The COMPANY shall determine if a rerun is required based on the ILI CONTRACTOR'S recommendation.

- **ANY DATA THAT NEEDS TO BE SENT FROM THE FIELD TECHNICIAN TO THE ANALYST MUST BE DELIVERED FROM THE TIME OF TOOL EXTRACTION TO THE ANALYST WITHIN 12 HOURS**.

- **ILI CONTRACTOR ANALYST MUST BE ON CALL AT ALL HOURS OF THE DAY OR NIGHT (24 hours 7 days of the week) TO RECEIVE AND PROCESS THE DATA TO MEET THE 24 HOUR TIMELINE LISTED ABOVE. ILI CONTRACTOR SHALL INCLUDE ANALYST STANDBY PRICING IN THEIR PROPOSAL TO MEET THIS MANDATE.**

- Successful inspection shall be determined in accordance with COMPANY'S engineering ILI Run Acceptance Criteria within 24 hours of inspection.

2.1.22. Data Alignment Deliverable**:** The following summarizes the ILI CONTRACTOR'S responsibilities for this issue:

- ***Prior to delivery of the final report***, the ILI CONTRACTOR shall submit a preliminary data alignment report. The purpose of this report is to align COMPANY supplied AGM and Survey Control Point (SCP) pipeline physical features (as identified in the GPS Control Survey) to the ILI CONTRACTOR tool generated inspection results for the same pipeline physical features. The report shall require the ILI CONTRACTOR to align their inertial mapping unit (IMU) data to match COMPANY AGM/SCP points to sub meter accuracy. There should be virtually no offset between COMPANY physical AGM/SCP features and the reporting ILI CONTRACTOR physical feature. This report shall also address any distance discrepancies between the coordinate locations generated by the ILI CONTRACTOR'S inertial mapping unit (IMU), and the distance generated by the ILI CONTRACTOR'S own odometer (for the same two points). This approach yields better aligned data that greatly facilitates anomaly siting for bellhole excavation. The ILI CONTRACTOR shall prepare a QA deliverable spreadsheet and map that illustrates how well the survey data compares to the original GPS Control Survey data. The QA spreadsheet and map shall illustrate both sets of data, and any offsets that occur between the COMPANY AGM/SCP locations and the ILI CONTRACTOR data locations. The ILI CONTRACTOR QA deliverable shall precede transmission of the ILI CONTRACTOR'S Final Report. Upon receipt, the COMPANY will determine whether or not the ILI CONTRACTOR data sufficiently aligns with COMPANY data. If the COMPANY discovers alignment problems, the COMPANY will work with the ILI CONTRACTOR to resolve the problems before the ILI CONTRACTOR delivers the ILI CONTRACTOR Final Report. Examples of items to check include:

2.1.22..1. Verify that geospatial distances (GPS-derived) agree with ILI CONTRACTOR odometer distances.

2.1.22..2. Verify that the AGM/SCP control points the ILI CONTRACTOR used to align primary sensor geophysical data match the original COMPANY GPS Control Survey AGM/SCP features.

2.1.22..3. Verify that there are no significant deviations when the ILI CONTRACTOR pipe geometry is superimposed on the COMPANY pipe geometry.

2.1.22..4. Verify and if necessary resolve discrepancies between the distance generated by the ILI Contractor odometer and the coordinate distance generated by the ILI Contractor inertial navigation system (INS) mapping tool, for the same two locations.

- To verify proper alignment, ILI CONTRACTOR shall provide COMPANY with an alignment summary in the following format:

Feature	AGM #	Company Lat	Company Long	Odometer	Vendor Lat	Vendor Long	Diff (Ft)
Valve	40	33.91629975	-118.39581573	3125.42	33.91629975	-118.39581573	0.0
ETS		33.91633624	-118.40704122	6532.34	33.91633617	-118.40702910	3.7

2.1.23. The ILI CONTRACTOR shall make available, at no additional cost to the COMPANY, personnel, telephone, cell phone, fax and e-mail contact information to support the COMPANY, while the COMPANY performs any investigations of anomalies or reported defects.

2.1.24. The ILI CONTRACTOR shall make available upon request of the COMPANY sample calculations of its analysis.

2.1.25. The ILI CONTRACTOR shall re-grade the results if determined by the COMPANY that the reporting specifications were not satisfied as a result of the analysis.

- **Data Analysis for Bend Strain Reporting**

2.1.26. Bend Strain Reporting: The following summarizes the ILI CONTRACTOR'S responsibilities for this issue:

- This section represents an initial attempt to outline the requirements and to provide a basis for additional discussions and planning. Typical inertial surveys are focused mainly on the "mapping" of the pipeline (based on numerical integration of the IMU and odometer data) with respect to specified GPS tie points and identification of key pipeline features along the alignment. If the ILI CONTRACTOR has an example outline or template of their typical inertial report format, it should be provided for review as part of the PROPOSAL REQUEST submittal. A supplemental "strain report" document should also be provided as one of the deliverable items from the inertial survey. The "Bid Worksheet" identifies those pipelines requiring Bend Strain Reporting.
- The COMPANY'S primary interests are in the pipeline bending strain and/or curvature information, which can be computed based on numerical differentiation of the IMU and odometer data. Many of the COMPANY'S pipelines pass through seismic hazard areas (such as earthquake fault zones) so there is an interest in reviewing the processed inertial data to look for areas of relatively high bending strain or curvature associated with potential permanent ground movement. Curvature signals/profiles resulting from field cold bends and fabricated elbows will tend to be fairly short (e.g., less than one joint length), whereas ground movement-induced curvature

signatures/profiles will tend to develop over relatively longer lengths (e.g., more than one joint length). Therefore, the base length of the curvature feature or "lobe" is one way to distinguish field bends and elbows from bending strains resulting from ground movement. Also, cold bends and elbows will stand out as significant angle changes with large strain/curvature values (for example, a cold bend in an NPS24 pipeline will have a nominal bend radius of 720" (30D), which corresponds to an apparent bending strain of about 1.7%). For a given pipeline, The COMPANY will have a set of Strip Maps (construction drawings) and pipe books that provide a log of the location of all known elbows and field bends. As part of the strain report, it is expected that the vertical, horizontal and resultant curvature or bending strain be computed for the entire length of the pipeline and that the resultant curvature/bending strain profiles be screened for locations of interest. The ILI CONTRACTOR shall have leeway in identifying anomalous bends based on experience and/or using his standard screening procedures. For the first inertial survey of a given pipeline, a screening criterion that would "flag" any locations along the pipeline with a maximum resultant bending strain of 0.1% or more with a lobe length longer than one pipe joint (i.e., crossing over a girth weld) is suggested. Alternatively, it may be simpler for the ILI CONTRACTOR to screen out (identify) the 5 or 10 locations with the highest resultant bending strain (excluding field bends and elbows). For subsequent inertial surveys, the screening criteria would be supplemented to look for specified changes in the bending strain/curvature profiles. For all areas that are flagged by the screening process, the following information should be provided:

- Items to be Tabulated for Features of Interest:

2.1.26..1. Station or Odometer Distance
2.1.26..2. Latitude and Longitude (decimal degrees), WGS 84 Datum
2.1.26..3. Estimated length of feature of interest
2.1.26..4. Vertical, horizontal and resultant/total bending strain based on 10' curvature calculation gage length
2.1.26..5. Vertical, horizontal and resultant/total bending strain based on curvature calculation gage length equal

to cup-to-cup length of pig canister containing the IMUs

- Items to be Plotted for Features of Interest:

  2.1.26..1. Plan view "map" plot of Easting vs. Northing with equal Easting and Northing scales
  2.1.26..2. Along the pipe profile view plot of elevation vs. odometer distance or station distance
  2.1.26..3. Along the pipe profile view plots of horizontal, vertical and resultant bending strain (based on 10' curvature calculation gage length) vs. odometer distance or station distance
  2.1.26..4. Along the pipe profile view plots of horizontal, vertical and resultant bending strain (based on curvature calculation gage length equal to cup-to-cup length of pig canister containing the IMUs) vs. odometer distance or station distance
  2.1.26..5. Pitch angle (degrees) vs. odometer distance or station distance
  2.1.26..6. Azimuth or yaw angle (degrees) vs. odometer distance or station distance

- Notes for Bend Strain Reporting

  2.1.26..1. All along the pipe profile plots the locations of pipeline girth welds shall be denoted using a symbol like "o" or "+" or a vertical line or equivalent symbology.
  2.1.26..2. Plots should be presented for a distance of approximately 200 (to 300) feet centered on the high strain zone
  2.1.26..3. Plots vs. odometer distance or station distance should show the distance on the X axis and the quantity of interest on the Y axis. The Y axis should be "*auto-scaled*" (i.e., maximum Y axis value slightly larger than Y_{max} and minimum Y axis value slightly smaller than Y_{min}) in order to provide a *zoomed* view of the quantity of interest wherein the details of the signal will be clearly visible.

2.1.26..4. The units of all plotted and tabulated quantities should be clearly denoted in all plots and tables.

2.1.26..5. All references to curvature and/or bending strain should identify the curvature calculation gage length (e.g., a 10’ curvature calculation gage length or a curvature calculation gage length equal to cup-to-cup length of pig canister containing the IMUs)

2.1.26..6. For each high strain zone, it shall be noted whether or not any pipe ovality or out-of-roundness was detected. If the inertial survey also includes high resolution caliper measurements, then the screening criteria should be extended to include a review of the caliper data. For the areas flagged by the bending strain criteria discussed above, detailed profile plots of pipe out of roundness (if present) shall also be included. Also, any locations with dents or ovality features of 2% of the pipe diameter or more shall be identified and plotted in the screening report.

2.1.26..7. Similarly, any high strain zone at/near a girth weld shall note whether or not rotational or translational misalignment was detected at the weld

2.1.26..8. For each high strain zone, it shall be noted whether or not any metal loss was detected at/near the high strain location.

- Any ILI CONTRACTOR specific calculations for localized strains due to pipe wall deformations shall also be provided.

- The ILI CONTRACTOR shall include a standard overall inertial measurement unit (IMU) mapping report. The report to include the following information:

2.1.26..1. A summary of the tool specifications

2.1.26..2. A summary of the sensor accuracies

2.1.26..3. A description of the algorithm used to compute curvature/bending strain

2.1.26..4. Documentation of the accuracy realized during the survey (what was the realized position accuracy and curvature/bending strain accuracy and did they meet or exceed specifications)

2.1.26..5. A profile plot of the tool velocity during the survey

2.1.26..6. A detailed drawing of the pig that was run showing all pertinent dimensions (including cup-to-cup distances) and locations of all sensors.

- Once the COMPANY has reviewed the strain report, additional detailed data files may be requested from some or all of the locations that were flagged by the data screening. The detailed data files should be provided in digital (Excel or ASCII) format for a specified distance upstream and downstream of the location of interest. The following columns of data would be requested at the raw data spacing:

2.1.26..1. Latitude specified in WGS-84 decimal degrees (8 decimal places)

2.1.26..2. Longitude specified in WGS-84 decimal degrees (8 decimal places)

2.1.26..3. Elevation referenced to Mean Sea Level (International feet, 2 decimal places)

2.1.26..4. Tool velocity (feet/second)

2.1.26..5. Pipe chainage distance and/or Company station distance (feet)

2.1.26..6. Pitch angle (degrees)

2.1.26..7. Azimuth or yaw angle (degrees)

2.1.26..8. Vertical bending strain (or curvature) for a 10-foot gage length

2.1.26..9. Horizontal bending strain (or curvature) for a 10-foot gage length

2.1.26..10. Total/resultant bending strain (or curvature) for a 10-foot gage length

2.1.26..11. Vertical bending strain (or curvature) for a gage length equal to the cup-to-cup (or wheel-to-wheel) length of the pig canister containing the inertial measurement unit (IMUs)

2.1.26..12. Horizontal bending strain (or curvature) for a gage length equal to the cup-to-cup (or wheel-to-wheel) length of the pig canister containing the inertial measurement unit (IMUs)

2.1.26..13. Total/resultant bending strain (or curvature) for a gage length equal to the cup-to-cup (or wheel-to-wheel) length of the pig canister containing the inertial measurement unit (IMUs)

- A summary tabulation of the girth weld detection data should also be provided with a tally of the chainage or station associated with each girth weld. The ILI CONTRACTOR may also provide specialized software that can be used to view and/or export the survey data along with the survey data.

- ILI CONTRACTOR'S digital data will be used to implement the centerline strain calculations per the procedures outlined in COMPANY'S PRCI report. Data will be used to determine the odometer, pitch and azimuth data to compute curvature/bending strain using any desired gage length.

- ILI CONTRACTOR shall align their IMU and odometer data to match the COMPANY'S GPS Control Survey control points to sub meter accuracy. Wherever possible, the COMPANY establishes Above Ground Markers (AGMs) and other intermediate Survey Control Points (SCPs) coincident with physical features, e.g., valves, taps, tees, ETSs, bends, girth welds on spans, etc. There should be virtually no offset between an AGM and the associated physical feature. This approach yields better aligned data that greatly facilitates anomaly siting for bellhole excavation. To verify proper alignment, contractor shall provide company with an alignment summary in the following format:

Feature	AGM #	Company Lat	Company Long	Odometer	Vendor Lat	Vendor Long	Diff (Ft)
Valve	40	33.91629975	-118.39581573	3125.42	33.91629975	-118.39581573	0.0
ETS		33.91633624	-118.40704122	6532.34	33.91633617	-118.40702910	3.7

- **Documentation and Reports**

2.1.27. The ILI CONTRACTOR shall provide documentation to demonstrate that they are experienced in conducting the requested ILI services and that their personnel are qualified to conduct the required tasks including tool calibration, field work and data analysis.

2.1.28. The ILI CONTRACTOR shall issue a benchmark report whereby the distance between aboveground markers per the odometer of the ILI CONTRACTOR'S inspection tool is compared to COMPANY'S pipeline station numbers.

2.1.29. A preliminary report may be requested by the COMPANY depending on the expected severity of metal loss. If requested, format, timing and content will be mutually agreed between COMPANY and ILI CONTRACTOR. Typically, if requested, ILI CONTRACTOR shall provide a preliminary MFL report to the COMPANY within 10 calendar days of removing the inspection tool from the pipeline. Typically preliminary MFL report shall identify all wall loss features with predicted maximum defect depths greater than 50% of the wall thickness, as well as all features that have a Rupture Pressure Ratio less than 1.1

2.1.30. The ILI CONTRACTOR shall provide the, Modified B31G (.85dL) and Effective Area Method predicted failure pressure (Pf) based on metal loss indications identified by the inspection tool. The ILI CONTRACTOR shall also provide the Rupture Pressure Ratio (RPR) calculated using the following formula for each metal loss anomaly and cluster of metal loss.

Where: $$\text{RPR} = \frac{Pf}{\text{MAOP}}$$

Pf = Predicted failure pressure (also called burst pressure) calculated using Effective Area Method and Modified B31G equations.

MAOP = DOT defined Maximum Allowable Operating Pressure for the pipe segment as provided by the COMPANY. If requested, ILI CONTRACTOR shall provide to the Company it's procedures and equations for calculating Pf and RPR.

2.1.31. The ILI CONTRACTOR shall use the following Interaction Rules in their data analysis and documentation reporting. The Interactions Rules are intended to represent the maximum separation distance between areas of metal loss (boxes) to be considered interacting for determining failure pressure using Modified B31G or Effective Area Method

Circumferential spacing:	Six (6) times wall thickness (6t)
Axial spacing:	One (1) inch.

2.1.32. The ILI CONTRACTOR shall provide a comprehensive data summary and analysis Final Report to the COMPANY within 60 calendar days following the removal of the tool from the pipeline. The Final Report shall include the following.

- A Pipe Tally List that indicates all features detected by the tool(s). The ILI CONTRACTOR will receive a Pipe Tally List Excel spreadsheet template which will be used for reporting features detected by the tool(s).

  2.1.32..1. Feature items required in the Pipe Tally List should include those listed in the, “COMPANY’S ILI Features Terminology” which is included later in this standard. Whenever possible the features should be identified using the COMPANY’S terms.

  2.1.32..2. Required column headings for the Pipe Tally List are shown below. For each designated feature/appurtenance/anomaly detected, the following data shall be listed and appear as column headings starting from left side of the report. The column headings listed below are the minimum requirements to be reported. If the ILI CONTRACTOR wants to add any additional column headings, the ILI CONTRACTOR should use approved acronyms listed in the “StdReportHeadings” tab included in the Pipe Tally List Template. The COMPANY should be contacted if the ILI CONTRACTOR wants to use an acronym which is not listed.

- Item No: ILI CONTRACTOR'S item number
- VendorFeature: ILI CONTRACTOR' feature name
- SempraFeature: COMPANY'S feature name
- SempraAlignmentID: COMPANY'S unique alignment ID number, assigned by the COMPANY for each GPS Control Survey feature.
- ClusterID
- Comments
- OdometerFt
- StationFt: COMPANY'S stationing in feet
- PipeDiameterInches
- WallThickInches
- DimensionClass: axial slotting, pitting, etc.
- Internal/External: anomaly location
- DepthInches
- DepthPercent
- AvgDepthInches
- LengthInches
- WidthInches
- OrientationOclock: units in o'clock (HH:MM)
- BendRadiusDeg: units in decimal degrees
- ModB31GBurstPressurePsi
- ModB31GRPR
- EffectAreaBurstPressurePsi
- EffectAreaRPR
- MAOPpsi: maximum allowable operating pressure
- PipeGradeSMYS: 52000, 60000, etc.
- JointNumber
- JointLengthFT
- LongSeamOclock: units in o'clock (HH:MM)
- DistFromUSWeldFt
- DistFromDSWeldFt
- USAGM: upstream above ground marker
- DistToUSAGMFt
- DSAGM: downstream above ground marker
- DistToDSAGMFt

- USReference: ETS, feature seen from grade, etc.
- DistToUSReferenceFt
- DSReference: ETS, feature seen from grade, etc.
- DistToDSReferenceFt
- LatitudeDeg: in WGS-84 (8 decimal places)
- LongitudeDeg: in WGS-84 (8 decimal places)
- ElevationFt: referenced to Mean Sea Level (International feet, 2 decimal places)
- AzimuthChangeDeg
- AzimuthDirection
- PitchChangeDeg
- PitchDirection
- Eventcode_ID: see Pipe Tally Event Code tab
- EventDescription: see Pipe Tally Event Code tab
- Type_CL: see Pipe Tally Event Code tab
- TypeDescription: see Pipe Tally Event Code tab

2.1.32..3. COMPANY'S ILI Features Terminology

The following information is the COMPANY'S requested terminology for the Pipe Tally List

- **Anomaly:** An indication, generated by non-destructive examination of an irregularity or deviation from base pipe or sound weld.
- **AGM (#):** Identifier for Above Ground Marker that can be used to locate the pipe from the surface. ILI CONTRACTOR should provide an identifying number according to the COMPANY'S Feature List or other numbering method.
- **Bend:** A forged fitting causing a directional change to the pipeline. ILI CONTRACTOR should provide the angle.
- **Bend-Miter:** Pipe joined at an angle connected by a girth weld. ILI CONTRACTOR should provide the angle.
- **Bend-Wrinkle (#):** Pipe bent to slightly change the angle using an approach that caused a wrinkle or wrinkles. Typically more than one wrinkle will occur

and the ILI CONTRACTOR should provide the number in parenthesis.

- **Buckle:** A bend, warp, or crumple in the pipeline that has been caused by external forces
- **Casing**: Steel pipe surrounding, but not attached, to the pipeline (ILI CONTRACTOR should provide casing length in the ILI data).
- **Close Metal Objects**: Indiscernible objects that have been detected adjacent to the pipeline but do not appear to be connected.
- **Cluster**: Two or more adjacent metal loss anomalies in the wall of a pipe or in a weld that may interact to weaken the pipeline.
- **Corrosion**: An electrochemical reaction of the pipe wall with its environment causing a loss of metal.
- **Crack**: A planar, two-dimensional feature with displacement of the fracture surfaces.
- **Dent**: A local change in surface contour caused by environmental or mechanical impact but not accompanied by metal loss.
- **Drip:** Tap on the pipeline used to drain liquids**.** ILI CONTRACTOR should provide diameter.
- **ETS:** Electrolysis Testing Station that generally has two steel leads attached to the pipe line where the testing unit can be attached. These are good above ground references and are very necessary for aligning the ILI Data accurately.
- **Flange:** Joined pipe by a bolted flange
- **Girth Weld Indication:** Construction related defects caused by poor fusion, misalignment, lack of penetration, etc. ILI CONTRACTOR should provide length.
- **Girth Weld**: Circumferential weld that connects pipeline segments or pipeline fittings.

- **Gouge**: Mechanically induced metal-loss, which causes localized elongated grooves or cavities.
- **Lamination**: Imperfection or discontinuity with a layered separation, which may extend parallel or angular to the pipe wall surface.
- **Long Seam Weld Indication:** Construction related defects caused by poor fusion, misalignment, lack of penetration, etc. ILI CONTRACTOR should provide length.
- **Manufacturing Indication:** Discontinuities or irregularities in the pipe showing metal loss anomalies that are not surface breaking. ILI CONTRACTOR should provide depth, length and width.
- **Metal Loss @ Dent**: A dent that has any indication of metal loss, cracking or a stress riser.
- **Metal Loss @ Long Seam**: Indications of metal loss affecting the long seam of a pipe segment.
- **Metal Loss @ Weld**: Any metal loss on a Girth Weld that is greater than or equal to 10% of the diameter.
- **Metal Loss**: Any metal loss on the transmission line that is greater than or equal to 10% of the diameter.
- **Mill Anomaly**: An anomaly that arises during manufacture of the pipe, as for instance a lap, sliver, lamination, non-metallic inclusion, roll mark and seam weld anomaly.
- **MLV:** Large Valves that dissect the pipeline. ILI CONTRACTOR should provide number according to the COMPANY'S Feature List.
- **Pipe Support:** Touching metal objects that are found along the pipe line where support is necessary.
- **Reducer:** A forged fitting that shows a reduction in pipe diameter
- **Sleeve:** Repaired pipe using a steel sleeve that is welded to the pipeline.

- **Tap**: A location on the pipeline showing a circular metal void. ILI CONTRACTOR should provide approximate sizing based on ILI Data.
- **Tee (barred or unbarred):** A forged fitting that joins the pipeline with another pipeline
- **Touching Metal Objects**: Indiscernible objects that appear to touch the pipeline.
- **X-ray Tap:** A reoccurring metal gain located near the girth weld that was used to assess the weld at the time of pipeline installation.

- An MAOP Breakdown List shall be included. This list contains a feature subset of the ILI Pipe Tally List containing the information from the most severe metal loss features prioritized by burst pressure according to Effective Area Method, and grouped into the following three categories:

  - Anomalies with Burst Pressures <1.1*MAOP
  - Anomalies with Burst Pressures ≥1.1*MAOP, but ≤1.39 *MAOP
  - Anomalies with ≤50% remaining wall thickness

- A Mechanical Damage/Mill Flaw List shall be provided for all mechanical damage and mill related features located on the pipe. This spreadsheet shall contain the following features information:

  - Dents with metal loss or other defects.
  - Dents affecting weld (long seam or girth)
  - Dents larger than 6% of the diameter

- A histogram of the metal loss showing the number of anomalies identified along the tool run distance.

- The final report shall include a graphic representation of the Rupture Pressure Ratio curve (RPR vs. odometer).

- The Final Report shall include a section providing analysis and quality evaluation of the ILI tool survey including tool performance, sensor performance, detection and speed impacts as related to tool specifications. This should include a graph of speed vs. odometer distance.

- The Final Report will include a section that describes the details of complying with the requirements of the latest version of API-1163 ILI Systems Qualification Standard concerning: Section 8.3 Pre-Inspection Requirements and Section 8.5 Post-Inspection Requirements.

- The Final Report shall include a copy or summary of the tool(s) performance specifications.

- An AGM benchmark Summary Table shall be included. This table will contain the following information for each AGM benchmark including launcher and receiver used for the smart tool runs:

  - ILI CONTRACTOR'S identifying number used in ILI final report
  - COMPANY'S identifying AGM number
  - Pipeline Survey Control Point (SCP) feature or appurtenance for the AGM benchmark (e.g. ETS, MLV, Tap)
  - Odometer
  - Latitude
  - Longitude
  - Elevation
  - AGM location description such as Street address or nearby intersection

2.1.33. The ILI CONTRACTOR shall provide two copies of the final report to the COMPANY.

- The Final Report shall include results, data, spreadsheets and Final Report verbiage on electronic media (CD or DVD) accompanied by appropriate ILI CONTRACTOR software. This "appropriate software" shall provide the COMPANY the ability to view the actual tool signals.

- All hard copy reports will be provided in a 3 ring binder using 8 ½" x 11" paper.

2.1.34. The ILI CONTRACTOR shall provide training to COMPANY personnel in the use of the appropriate software

2.2. Company Responsibilities

- **ILI Activities**

2.2.1. The COMPANY will identify tool technology to be utilized including but not limited to Metal Loss Tools (high resolution magnetic flux leakage, transverse magnetic flux leakage, or ultrasonic), Geometry Tools (caliper, bend, gauge or combination), Mapping Tools (GPS inertial mapping), tethered Tools, or Cleaning Tools

2.2.2. The COMPANY will furnish pipe data (MAOP, wall thickness, grade, diameter, etc.), fitting data (bend radius on elbows, minimum bore on flanges, bars on tees, etc.) via a Feature Line Summary spreadsheet, and information pertaining to flow rates and gas/fluid physical properties, as requested and available.

2.2.3. The COMPANY will complete and submit to the ILI CONTRACTOR their information Questionnaire detailing specific project information such as project location, description of work, line segmentation, scheduling, etc. The COMPANY will also provide the ILI CONTRACTOR with most recent data, such as geometry/bend tool reports, gauging pig results, etc., to allow the ILI CONTRACTOR to determine if pipeline modifications, including launching and receiving facilities, are recommended prior to the start of an ILI survey.

2.2.4. The COMPANY will provide equipment and operator to assist the ILI CONTRACTOR with inspection tool insertion and removal from the launching and receiving facilities. Typically this involves a crane and/or backhoe.

2.2.5. The COMPANY will provide personnel to operate launcher and receiver facilities.

2.2.6. The COMPANY will operate pipeline facilities.

2.2.7. The COMPANY will identify the work areas to the ILI CONTRACTOR including available equipment preparation, cleaning, refurbishment, and field data processing locations.

2.2.8. The COMPANY will be responsible for disposing of pipeline liquids and debris that result from the inspection tool run.

2.2.9. Tool Cleaning: The following summarizes the COMPANY'S responsibilities for this issue:

- The COMPANY shall provide all manpower necessary to clean the inspection tools after completion of an inspection. The COMPANY shall provide a cleaning area, all necessary tools (i.e. power sprayers, rags, etc.), and disposal of related cleaning equipment and liquids. The COMPANY'Ss preferred method of cleaning is water (H_20).

- The COMPANY shall provide cleaning services to ensure that hazardous materials and debris from COMPANY pipelines are removed from the pigs to ensure safe and compliant transport of the tools from the receiver site. This may or may not occur at the time of receiving the inspection tool, depending on time of day and other variables that may affect cleaning scheduling. Generally, the COMPANY will make every effort to clean the tools within a reasonable time (generally within 1 business day). The ILI CONTRACTOR shall not transport the tools off-site until the cleaning has been completed. If the ILI CONTRACTOR insists that the tool be removed from the site prior to cleaning, then the ILI CONTRACTOR shall take any and all liability regarding the transport and storage of the tool in the contaminated condition, and shall sign a document stating such.

- **Bend Strain Reporting Activities**

2.2.10. Bend Strain Reporting:_The following summarizes the items that the COMPANY will provide for this issue:

- Global positioning systems (GPS) control coordinates for Above Ground Markers (AGMs) and Survey control points

(SCPs) shall be provided in the GPS Control Survey document, in the following geographic coordinate system:

2.2.10..1. Latitude and Longitude (decimal degrees) Datum WGS 1984 with associated positional confidence metadata.
2.2.10..2. Pipeline centerline elevation referenced to Mean Sea Level with associated positional confidence metadata.
2.2.10..3. Many SCPs will also serve as calibration locations for tool tracking by means of above ground markers (AGMs).

- Survey accuracies:

2.2.10..1. SCP and any associated AGM position to be in sub-foot accuracy, and in no case worse than sub-meter accuracy, recorded in latitude / longitude decimal degrees to (8) decimals places; elevations recorded in decimal International feet, to (1) decimal place
2.2.10..2. SCP spacing shall be approximately spaced at ½ miles intervals in distance, where possible, and not to exceed 1-mile intervals.

- Survey control point (SCP) locations:

2.2.10..1. AGM locations
2.2.10..2. Launcher and Receiver valves
2.2.10..3. Fixed pipeline features such as mainline valves, tees, flanges, bends, or exposed girth welds that are physically attached to the pipeline.
2.2.10..4. Electrolysis test stations (ETS)

- Marker magnet to be provided by COMPANY:

2.2.10..1. Orientation: North pole oriented downstream and the south pole upstream of pipeline
2.2.10..2. Top of Pipe at the 12:00 O'clock

- Equipment specifications used:

2.2.10..1. As defined in **Standard 167.0245.** Overburden depth based on Radio Detection pipeline current mapper (PCM) or Metrotech locator device.

2.2.10..2. Elevation adjusted to center of pipeline.

- **Please note**: As a general rule, the COMPANY selects AGM and SCP features that coincide with physical features on the pipeline discernible by the ILI tool primary sensor, e.g., valves, CP attachments, taps, or girth welds on spans. The methodology and format of this GPS control survey is detailed in **Standard 167.0246.** Additionally, the COMPANY can provide the ILI CONTRACTOR (upon request) a pipeline geometry file (shape file format). The ILI CONTRACTOR will use this information to geospatially align the geophysical results of the pigging survey.

3. DEFINITIONS

3.1. Not Applicable

4. PROCEDURE

4.1. This document shall be attached to the request for proposal form that is sent to the ILI CONTRACTORS. This Standard provides detailed instructions for the ILI CONTRACTORS.

5. RECORDS

5.1. Not Applicable

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
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PURPOSE: **This standard establishes the requirements and procedures for responding to immediate repair conditions on Department of Transportation (DOT) defined transmission pipelines.**

1. POLICY AND SCOPE

1.1. Policy

This Gas Standard shall be controlled and reviewed per the guidelines established under the Quality Assurance Plan (QAP) and Management of Change Process (MOC) established under the Pipeline Integrity Management Program.

1.2. Scope

This procedure is applicable to all transmission pipelines within a covered segment(s) as defined by **Standard 223.0415**. These pipelines are located in the Distribution, Storage and Transmission departments. Gathering and distribution lines are excluded.

2. RESPONSIBILITIES & QUALIFICATIONS

Responsibility for implementing the field activities identified in this gas standard shall lie with appropriate Operations & Maintenance (O&M) personnel that are involved with immediate repair conditions in the field.

2.1. **Pipeline Integrity Engineer**

The Pipeline Integrity Engineer shall be responsible for applying the procedures established in this Gas Standard when an immediate repair condition is determined.

2.2. **Pipeline Integrity Department**

The Pipeline Integrity Department shall be responsible for the development of the procedures established in this Gas Standard.

2.3. **Inspection Personnel**

The Inspection Personnel (IP) shall be responsible for the assigned tasks corresponding to the data collection. They shall be responsible for conducting the inspections in accordance with Company procedures. The IP shall have appropriate certifications and possess the necessary equipment to perform all pipeline inspections.

2.4. All employees shall be responsible for adhering to company safety procedures and follow all protocols identified in the Injury and Illness Prevention Program Binder under **Manual IIPP.4.**

3. DEFINITIONS

Additional terms and definitions associated with this gas standard are provided in **Manual TIMP.A** and **Standard 223.0415**.

3.1. **Anomaly**: An unexamined pipe feature which is classified as a potential deviation from sound pipe material, welds, or coatings. All engineering materials contain anomalies which may or may not be detrimental to material performance. Indications of anomalies may be determined by nondestructive inspection methods such as in-line inspection (ILI).

3.2. **In-line Inspection (ILI) Tool**: ILI is an integrity assessment method used to locate and preliminarily characterize the condition of a pipeline. An ILI tool is a device or vehicle that uses a nondestructive testing (NDT) technique to inspect the pipeline from the inside. An ILI tool is also known as an intelligent or smart pig.

3.3. **Stress Corrosion Cracking (SCC)**: SCC is a form of environmental attack of the metal involving an interaction of a local corrosive environment and tensile stresses in the metal resulting in formation and growth of cracks.

3.4. **Superficial Corrosion**: Insignificant corrosion on the surface of the pipeline (less than or equal to 10% of nominal wall thickness) that has no direct impact on the remaining strength of the pipeline, and additionally no indirect material effect on pipeline integrity or secondary interactive impact to other threats.

4. PROCEDURE

4.1. Immediate Repair Conditions

Immediate repair conditions shall be evaluated within a period not to exceed **5 days** following determination of the condition in accordance with ASME B31.8S, *Managing System Integrity of Gas* Pipelines, Section 7. To maintain safety, the operating pressure shall be reduced in accordance with paragraph 4.3 or shut down the pipeline until repair of these conditions is completed. The following conditions require an immediate response:

4.1.1. A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure (MAOP) at the location of the anomaly. Additional guidelines for calculating the remaining strength of corroded pipe are provided in **Standard 182.0050**.

4.1.2. A dent having any indication of metal loss, cracking or a stress riser.

4.1.3. An indication or anomaly that based on the Pipeline Integrity Engineer's or Inspection Personnel's judgment could result in a likely risk of danger to the public, employees or pipeline and would require immediate repair or reduction in pipeline pressure. These conditions may include any of the following:

4.1.3.1. Pits with metal loss in excess of 80% of pipe wall thickness.

4.1.3.2. Severely distorted pipe segments subject to excessive stress loading.

4.1.3.3. Other pipe anomalies or defects where a likely rupture or leakage could occur.

4.1.4. Indications of metal loss, not including superficial corrosion, affecting the long seam of a pipe segment manufactured by direct current or low frequency electric resistance welding (ERW) or by electric flash welding.

4.1.5. Pipelines showing indications of SCC.

4.2. Remediation Requirements

Immediate repair conditions shall be remediated in accordance with **Standard 223.0180**. The Pipeline Integrity Engineer shall be responsible for recommending repair guidelines.

4.3. Temporary Pressure Reduction

When an immediate repair condition has been discovered a temporary operating pressure reduction shall be implemented to ensure safety of the impacted pipeline segment. The temporary operating pressure reduction shall be implemented using one of the following two possible methods:

4.3.1. The first method is to reduce the operating pressure to a level that is calculated by multiplying the predicted failure pressure, P_f, by a factor of safety that is based on class location. This method is discussed in **Standard 182.0050**:

4.3.1.1. For Class 1 locations, reduced operating pressure = P_f x 0.72

4.3.1.2. For Class 2 locations, reduced operating pressure = P_f x 0.60

4.3.1.3. For Class 3 locations, reduced operating pressure = P_f x 0.50

4.3.1.4. For Class 4 locations, reduced operating pressure = P_f x 0.40

4.3.2. The second and preferred method is to reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered.

4.4. Operator Notifications

4.4.1. The following departments shall be notified upon identifying an immediate repair condition:

4.4.1.1. Gas Control Operations

4.4.1.2. Gas Engineering – Pipeline Integrity

4.4.1.3. Local Transmission District Operations Manager and/or Distribution District Operations Manager

4.4.1.4. If it involves a Distribution pipeline – the Region Technical Services Manager shall be contacted.

4.5. Safety-related Condition Reporting

Safety-related conditions (SRC) are outlined 49 CFR 191.23 and 191.25 and include immediate response condition. SRCs and immediate response conditions must be evaluated within 5 days and remediated within 10 days. An SRC report must be filed with the Pipeline and Hazardous Material Safety Administration (PHMSA) for all safety-related and immediate conditions that are not remediated within the 10-day deadline. Additional guidelines on identifying and reporting safety related conditions are provided in **Standard 183.06**.

4.6. The following actions shall be taken if the evaluation of an immediate repair condition cannot be completed within 5 days and the subsequent remediation cannot be completed in a timely manner:

4.6.1. The conditions shall be documented and the California Public Utilities Commission (CPUC) and PHMSA shall be notified in accordance with **Standard 183.06**.

4.7. Long-Term Pressure Reduction

If the pressure reduction due to an immediate repair condition must be maintained for longer than 365 days, the CPUC and PHMSA will be notified in accordance with **Manual TIMP.20**. Gas Engineering Pipeline Integrity shall provide the following information:

4.7.1. Explanation and reasons for the remediation delay.

4.7.2. Technical justification that the continued pressure reduction does not jeopardize the integrity of the pipeline.

4.7.3. Description on how the public will not be jeopardized.

5. OPERATOR QUALIFICATION COVERED TASKS
(See GS **167.0100,** *Operator Qualification Program*, **Appendix A**, *Covered Task List*)

- **Task 2.6.** - 49 CFR 192.465(d) **-** Taking prompt action to correct any deficiencies indicated by monitoring
- **Task 2.14. -** 49 CFR 192.485 - Recognizing general and localized corrosion, taking action: Transmission
- **Task 10.1.** - 49 CFR 192.711 – Recognizing a leak, imperfection, or damage that impairs serviceability of a transmission line
- **Task 10.2.** - 49 CFR 192.713 – Making permanent field repair of imperfections and damages on transmission lines
- **Task 10.3.** – 49 CFR 192.715 – Making permanent field repair of welds on transmission lines
- **Task 10.4.** - 49 CFR 192.717 – Making permanent field repair of leaks on transmission lines

6. RECORDS

6.1. Discovery and determination dates, pressure reduction, repair of conditions, etc. shall be documented using all applicable Company forms, including but not limited to the following:

6.1.1. Company **Form 677-1.**

6.1.2. Company **Form 2112.**

6.1.3. All applicable forms contained within **Standard 167.0210.**

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
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PURPOSE **The purpose of this procedure is to describe the process of using Guided Wave, also known as Long Range, Ultrasonic inspection to assess the integrity of natural gas pipelines.**

1. POLICY AND SCOPE

This procedure shall be used in conjunction with any Guided Wave Ultrasonic (GWUT) inspection intended to satisfy integrity assessments as either a complementary tool or as a stand-alone assessment method as "other technology" as defined in 49 CFR 192.921 (a)(4) and 192.937 (c)(4).

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **GWUT Inspection Program Manager (IM):** The GWUT Program Manager has the overall program oversight and responsibility to assure that this procedure is implemented effectively and is fully integrated with the Company Integrity Management Plan (IMP).

2.2. **GWUT Inspection Project Manager (PM):** The GWUT Project Manager is responsible for ensuring that all aspects of the assigned projects are conducted in full compliance with this procedure. In addition, the Project Manager is responsible for planning, documenting, and communicating various aspects and stages of the assigned GWUT projects including:

- Review and approval of contractor inspection procedures.
- Verification of inspection results.
- Remaining strength evaluations.
- Response to discovery of anomalies.

The Project Manager shall be sufficiently trained in Guided Wave inspection technology. Documented participation in training classes given by the manufacturers or providers of the technology shall constitute adequate training. This procedure has response time requirements. The Project Manager has point responsibility to assure that those time requirements are met throughout the project.

2.3. **GWUT Inspection Project Engineer (PE):** The Project Engineer is responsible for the technical oversight and support of evaluations and analyses conducted throughout the assessment process. These include, but are not limited to, sensitivity analysis and direct examination results. This procedure has various response time requirements pertaining to the priority of the discovered features. The Project Engineer will be responsible for meeting those scheduling requirements.

2.4. **Direct Examination Personnel (DP):** The Direct Examination Personnel are responsible for conducting the inspections and tests in accordance with this procedure and other testing procedures that have been referenced in the assessment process.

3. DEFINITIONS

3.1. **Call DAC:** Distance amplitude curve representing a fixed proportion of the Weld DAC (typically 40% of the weld DAC for Guided Ultrasonics Limited (GUL) systems, for example). The Call DAC may be used as a threshold for reporting the detection of features or as a benchmark for estimating feature size.

3.2. **Characterization:** The process of determining the origin of a Guided Wave signal reflection; i.e., assigning **type**, **location**, and **size** attributes to a detected feature. Features may be characterized as "unknown."

3.3. **Critical Defect Size:** A flaw size that would fail in a hydrotest conducted according to the requirements of CFR 49 Part 192 Subpart O.

3.4. **Dead Zone:** The length of pipe immediately adjacent to the transducer collar that cannot be inspected because the receiving transducers are shut off while the transmitting transducers are generating the torsional waves. The length of the dead zone is related to the number of cycles and the speed of sound in the material. The WaveProG3 software automatically calculates and displays the dead zone.

3.5. **Defect:** A flaw that requires repair in order to maintain the current MAOP.

3.6. **Depth:** The dimension of a feature measured in the radial direction from the surface of the pipe to the surface of the feature. In the case of external corrosion the depth is measured from the nominal OD of the pipe to the corroded surface. GWUT depth data is typically expressed as a percentage of the nominal wall thickness.

3.7. **Desired:** "Desired" data listed in Table 1 in the "Need" column should be obtained if reasonably possible or easily measured. Its omission does not require approval or documentation.

3.8. **Distance Amplitude Curve (DAC):** A DAC illustrates the exponential decay in signal strength as distance from the source increases. Signal strength is expressed in terms of amplitude, using millivolts as the unit of measurement. The DAC is established based on the output of the system, the reflection from a feature of known attributes, and the observed decay rate (attenuation) in signal amplitude as distance from the transducer collar increases. The sensitivity along the length of a DAC is constant. Inspection systems may allow multiple DAC curves of specific sensitivities to be displayed.

3.9. **Estimated Cross Sectional Area Change (ECL):** Guided wave inspection detects changes in the cross sectional area (CSA) of the pipe wall. Test equipment software provides a percent estimate of the change (gain or loss) and is often expressed as % ECL (estimated cross sectional loss).

3.10. **Feature:** A pipeline attribute that produces a detectable signal reflection or perturbation that can be characterized. Features include, but may not be limited to:

- Various types of attachments to the pipe.
- Changes in pipe thickness (either from corrosion or changes in nominal thickness).
- Transitions to different materials in contact with the pipe.
- Changes in pipe shape or direction.

Examples of features include: metal loss (corrosion), denting or other mechanical damage, a hard contact (such as a pipe support or casing centralizer), tee or branch connections, welds, pipe fittings, pipe bends, flanges, and transitions between buried/submerged pipe to unburied segments.

3.11. **Flaw:** An imperfection that may or may not require repair. Examples include corrosion, manufacturing or fabrication-related imperfections, dents, cracks, buckles, and gouges.

3.12. **Guided Wave UT Inspection (GWUT):** Ultrasonic inspection of pipe using low frequency) sound waves induced into the pipe through a collar of UT transducers. The waves propagate in several modes for long distances along the length of the pipe. Analysis of wave mode reflections (typically flexural and/or compressional) is used to detect and characterize features.

3.13. **Inspectable Range:** The maximum distance from the transducer collar at which acceptable sensitivity is achieved.

3.14. **Known Feature:** A feature whose characterization can be determined from Pre-Assessment data such as pipeline records, strip maps, or the pipeline database.

3.15. **Length:** The dimension of a feature measured in the axial direction of the pipeline.

3.16. **Long Flaw:** For the purpose of evaluating the remaining strength of a corroded area using ASME Standard B31G, a "long flaw" is flaw having an axial length greater than:

$$\sqrt{20 * D * t}$$

where:

D= pipe outside diameter (inch), and
t = pipe nominal wall thickness (inch)

3.17. **Near Field:** An area one to two feet out from the Dead Zone, where results can be poor or inconclusive because the receiving amplifiers are ramping up in power.

3.18. **Noise DAC:** The Noise DAC is a fixed proportion of the Weld DAC. It may or may not represent the actual amplitude of "noise", depending upon the pipe condition and the presence or absence of mechanical noise in the pipeline. The Noise DAC is another benchmark that can be used to estimate feature size.

3.19. **Region of Concern (ROC):** Any area where excavation is not possible or desirable, i.e., casing, river crossing, environmentally sensitive area, etc.

3.20. **Required:** "Required" data listed in Table 1 in the "Need" column are data elements that must be accounted for in the assessment process.

3.21. **Safety Factor:** The safety factor is the ratio of estimated failure pressure (Pf) to MAOP. The failure pressure is calculated using GAS STANDARD **182.0050,** *MAOP Evaluation of Corroded Pipe*.

3.22. **Sensitivity:** The minimum detectable feature size, expressed as a percentage of the cross sectional area of the pipe wall. For example at 5% sensitivity, a feature with a cross sectional area of 2.5 square inches (in a transverse cross section - i.e., depth vs. width) is detectable in a pipe wall having a cross sectional area of 50 square inches.

3.23. **Shall:** A requirement that must be followed, or its exception must be approved and documented in accordance with Section 9.0 of this procedure.

3.24. **Shot Distance**: The maximum distance from the transducer collar at which the minimum acceptable sensitivity is reached.

3.25. **Should:** A recommendation that is desirable to follow whenever possible. Deviating from the recommendation does not require documentation or approval.

3.26. **Validation:** The process of demonstrating (through verification) that the inspection method is **sensitive** to a minimum standard, and therefore is **justified** in the assessment of non-verifiable features. The process is designed to increase the confidence that the inspection and analysis have correctly evaluated inaccessible portions of the pipe.

3.27. **Verifiable Feature:** An uncorrelated feature that is accessible and may be evaluated by direct examination.

3.28. **Verification:** To measure or confirm the **accuracy** of the characterization by comparison against a known feature.

3.29. **Weld DAC:** Distance amplitude curve aligned with the average peak height of signals reflected from girth welds. The signal amplitude is related primarily to the ratio of the weld root and cap reinforcement to the nominal thickness of the pipe.

3.30. **Width:** Dimension of a feature measured in the circumferential direction.

4.0 PROCEDURE

4.1 Pre-Assessment

4.1.1 Objective

Pre-Assessment serves four purposes:

- Determine if GWUT will assess the applicable categories of integrity threats.
- Identify the likely morphology of metal loss to support characterization of new or previously undiscovered features.
- Establish the locations and types of known pipeline features that can serve as benchmarks during the inspection process.
- For threat categories assessable by GWUT, determine if GWUT is feasible based on sensitivity levels required to validate pipeline integrity.

4.1.2 Data Collection

Data pertinent to the Pre-Assessment process is summarized in **Table 1 – Guided Wave Pre-Assessment Data**. This data will serve to aid in the threat identification, feasibility analysis, and the validation efforts.

Data elements are listed as either “Required” or “Desired.” Required data elements shall be collected before the completion of Pre-Assessment; “Desired” elements should be obtained if available in existing records or if they can be easily obtained from measurements or examinations.

Data elements are recorded in **Form A: Data Element Check Sheet**.

4.1.3 Identify Likely Threats to Support Characterization of Unknown Features

Review the pipeline operating and maintenance history (e.g. direct examination data, ILI data, or pipeline records for the subject pipeline segment) to reveal the form, severity, and typical circumferential orientation of anticipated threats that may be detected by GWUT. Prior knowledge of anticipated or previously observed forms of corrosion may assist an inspector in correctly characterizing features. Information regarding previously discovered corrosion or mechanical damage is recorded on Line 7 of **Form B: Register of Known Features**.

4.1.4 Establish Known Pipeline Features

A key outcome of the Pre-Assessment is the designation of known pipeline features. Known features and their corresponding locations serve as benchmarks to verify the accuracy of inspection results and axial distance measurements. SoCalGas staff complete Fields 1, 2, and 3 and columns A, C, D, and E of **Form B: Register of Known Features** and supply the completed form to the inspection personnel prior to the inspection.

4.1.5 Determine Guided Wave UT Feasibility

GWUT is an appropriate assessment method for detection of volumetric metal loss defects associated with internal corrosion, external corrosion, and mechanical damage integrity threats. GWUT is also capable of detecting several physical pipeline features unrelated to metal loss.

The range of a GWUT inspection is determined by two parameters: the sensitivity requirement and the required signal to noise ratio.

4.1.5.1 Sensitivity

For casings, a sensitivity of less than or equal to 5% of the cross sectional area (CSA) must be achieved. In addition, the sensitivity achieved must be able to identify the smallest defects that will fail by rupturing in a hydrostatic test. Appendix A demonstrates the method for calculating this defect size.

For non-cased pipe, there is no strict sensitivity requirement. The PM should use good engineering judgment to specify the minimum sensitivity. It is recommended that the PM consider failure pressure, MAOP, and the limitations of the GWUT technique when selecting the sensitivity. An appropriate solution is outlined in Appendix A.

4.1.5.2 Determination of Range

The PM shall determine the minimum range needed for the GWUT assessment of a pipe segment inspection zone. The first step is to determine probable collar locations. Shots from adjacent collar locations must show a minimum 5% overlap for the segment to be completely inspected. For example, Figure 3.3 depicts a hypothetical casing to be inspected using GWUT. Collar 1 is placed 5 feet from the casing to ensure that the near field and dead zone can be proven up correctly. Because of access or some other consideration, collar 2 must be placed 10 feet away from the casing. The minimum *combined* shot distance would be (5+50+10)*1.05 or 68.25 feet. The PM shall document the minimum GWUT range on, if applicable.

Maximum Range

For an inspection of cased pipe, shots should be taken from both ends of the casing. For planning purposes, an estimated range of 80 feet is recommended; however, the PM may exercise his/her judgment to change the estimate. Caution: The actual range of the shot is determined after it is taken, and depends on factors like coating and spacers. If neither shot meets the minimum sensitivity requirement at some point in the casing, GWUT is not feasible and another inspection method must be used.

For non-cased segments, if the required range of GWUT assessment exceeds 80 feet, then multiple access locations to the pipe should be made to keep the GWUT assessment shots less than 80 feet with a ten foot overlap. Bell holes should be spaced no further than 140 feet apart; 100 foot spacing is recommended.

An example of determining the minimum required range is given in Figure 4.1. The combined shot distance is calculated by adding the shot distances of collars 1 and 2. Note that the combined shot distance is at least 5% longer than the adjacent collar distance.

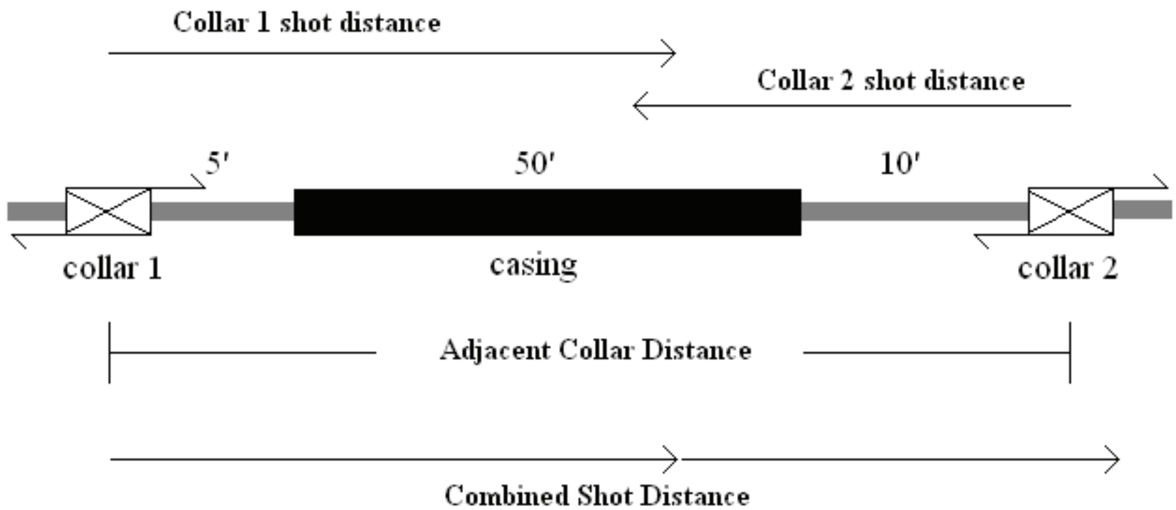

Figure 4.1: Minimum required range example.

Table 1 – Guided Wave Pre-Assessment Data

ID #	Data Element	Use & Interpretation Of Results	Need [1]	Impacts Cased Pipe	Impacts Buried Pipe	Affects Suitability for Guided Wave Assessment	Affects Characterization of Features Found by Guided Wave UT	Affects the Impact of a Feature on Integrity	District/Archive Files	GIS	Field	Pipeline Databases	Maps Other
1.0 Pipe Related													
1.1	Material and Grade	The SMYS will be used for predicted burst pressure calculations that will influence the remaining life calculations.	R	Y	Y	N/R	N/R	R					
1.2	Diameter	The diameter will be used for selection of the appropriate transducer collar size. It is also used in burst pressure calculations that will influence the remaining life calculations. A known change in diameter assists in interpretation of features.	R	Y	Y	R	D	R					

[1] Notes on abbreviations: R = Required D = Desired N/R = not relevant Y = yes N = no

ID #	Data Element	Use & Interpretation Of Results	Need [1]	Impacts Cased Pipe	Impacts Buried Pipe	Affects Suitability for Guided Wave Assessment	Affects Characterization of Features Found by Guided Wave UT	Affects the Impact of a Feature on Integrity	District/Archive Files	GIS	Field	Pipeline Databases	Maps Other
1.3	Wall thickness	The wall thickness will be used for predicted burst pressure calculations as well as remaining life calculations. A known change in thickness assists in interpretation of features.	R	Y	Y	N/R	D	R					
1.4	Year manufactured	Vintage may provide indication of manufacturing practices that relate to material properties and surface features.	D	Y	Y	N/R	D	D					
1.5	Seam Type	Older pipe typically has lower weld seam toughness that reduces critical defect size. Pre-1970 ERW or flash welded pipe may be subject to higher corrosion rates than the base metal.	D	Y	Y	N/R	D	D					

ID #	Data Element	Use & Interpretation Of Results	Need [1]	Impacts Cased Pipe	Impacts Buried Pipe	Affects Suitability for Guided Wave Assessment	Affects Characterization of Features Found by Guided Wave UT	Affects the Impact of a Feature on Integrity	District/Archive Files	GIS	Field	Pipeline Databases	Maps Other
1.6	Bare pipe	Bare pipe or transitions from coated to bare influence inspection range and may produce detectable features.	D	Y	Y	N/R	D	D					
2.0 Construction Related													
2.1	Year installed	Impacts time over which coating degradation may occur, defect population estimates, and corrosion rate estimates.	D	Y	Y	N/R	N/R	D					
2.2	Recent route changes/	Some fittings may limit inspection beyond the fitting.	R	Y	Y	R	R	N/R					

	modifications not reflected in drawings												
2.3	Backfill Construction practices	Some backfill (i.e., concrete) may severely limit inspection range. Significant changes in backfill may be detectable features.	R	N	Y	R	D	N/R					
2.4	Location of major pipe appurtenances such as valves, and taps	Some appurtenances may prevent inspection beyond the feature.	R	N	Y	R	D	N/R					
2.5	Length of casings	Casing length influences the number of access points needed.	R	Y	N	R	D	N/R					
2.6	Type of casing end seal	These are detectable features that can aid in data interpretation. May have some minor influence on inspection range.	D	Y	N	D	D	N/R					
2.7	Presence or absence of metallic short	These are detectable features that can aid in data interpretation. May have some minor influence on inspection range and future corrosion	D	Y	N	D	D	D					

2.8	Type and spacing of insulators/ centralizers	These are detectable features that can aid in data interpretation. May have some minor influence on inspection range.	D	Y	N	N/R	D	N/R					
2.9	Location of bends, including miter bends and wrinkle bends	Some fittings may affect inspection and may make metal loss difficult to detect. Remaining strength assessments are different for metal loss on fittings	R	N	Y	R	R	R					
2.10	Underwater sections and river crossings	Immersion influences inspection range and the feasibility of performing direct examinations	R	N	Y	R	D	N/R					
2.11	Locations of river weights or anchors	These are detectable features that can aid in data interpretation. May have some minor influence on inspection range.	D	N	Y	N/R	D	N/R					
3.0 Soil and Environmental													
3.1	Soil characteristics & types including soil contamination	May influence inspection range. Influences corrosion rate and remaining life assessment	D	N	Y	D	D	D					
3.2	Drainage	Influences corrosion rate and	D	N	Y	N/R	N/R	D					

		remaining life assessment											
3.3	Presence or absence of electrolytic short	These are detectable features that can aid in data interpretation. May have some minor influence on inspection range.	D	Y	N	D	D						
3.4	Frozen ground	Influences inspection range	R	N	Y	D	N/R	N/R					
4.0 Corrosion Control													
4.1	Test point locations (pipe access points)	These may be detectable features that can aid in data interpretation	D	N	Y	N/R	D	N/R					
4.2	CP maintenance history (rectifier adjustments, anode maintenance, etc.) over the past five years	May help establish likely time that corrosion occurred in buried sections, and assist in determination of corrosion rate	D	N	Y	N/R	N/R	D					

4.3	1st Assessment Requirement**:** All available CP Maintenance History	May help establish likely time that corrosion occurred in buried sections, and assist in determination of corrosion rate	D	N	Y	N/R	N/R	D					
4.4	Years without CP applied	Negatively affects ability to estimate corrosion rates and make remaining life predictions for buried pipe	N/ R	N	N	N/R	N/R	N/R					
4.5	Coating type-pipe	Coating type will influence inspection range. Change in coating type may be a detectable feature	D	Y	Y	D	D	N/R					
4.6	Coating type-joints	Coating type will influence inspection range. Change in coating type may be a detectable feature	R	Y	Y	D	D	N/R					
4.7	Coating condition	Coating condition may influence inspection range and sensitivities	D	Y	Y	D	D	N/R					
4.8	Routine pipe to soil potential survey data/history	Suspected corrosion may influence interpretation of guide wave UT data	D	N	Y	N/R	D	N/R					
4.9	Data from other over the ground	Other assessment data can be used to validate guided wave results or influence selection of	D	N	Y	N/R	D	N/R					

	surveys (DCVG, CIS, or similar)	direct examination sites												
5.0 Operational Data														
5.1	Operating stress level	Impacts critical flaw size and remaining life predictions	R	Y	Y	N/R	N/R	R						
5.2	Monitoring programs (Coupon, patrol leak history etc.)	Provides information regarding anticipated corrosion size and morphology	R	Y	Y	N/R	N/R	R						
5.3	Pipe inspection reports-excavation	May provide insight into corrosion rate. Known location of corrosion may influence interpretation of GWUT data	D	Y	Y	N/R	R	R						

5.4	Repair history/records, steel/composite repair sleeves, repair locations	Suspected corrosion and presence of repairs may influence interpretation of GWUT data.	D	Y	Y	N/R	D	N/R						
5.5	Leak rupture history	May be useful in selecting corrosion rate for remaining life analysis. Suspected corrosion may influence interpretation of GWUT data.	D	Y	Y	N/R	D	D						
5.6	Evidence of external or internal MIC	May influence estimation of corrosion rate. Suspected corrosion may influence interpretation of GWUT data.	D	Y	Y	N/R	D	D						
5.7	Type and frequency of third party damage	Suspected damage may influence interpretation of GWUT data, although perhaps only applicable to buried, rather than cased segments.	D	N	Y	N/R	D	N/R						
5.8	Hydro test dates/pressures	Pressure test results can bound the limits of probable existing flaw size.	R	Y	Y	N/R	N/R	D						
5.9	Other prior integrity related activities – CIS, ILI runs, etc.	Other assessment data can be used to validate guided wave results or influence selection of direct examination sites.	R	Y	Y	N/R	D	N/R						

4.2 Contractor Procedures, Equipment, and Qualifications

The contractor shall follow the details of the approved procedure to generate and interpret the Guided Wave data.

4.2.1 Contractor Procedures and Qualification

The GWUT Inspection Project Manager PM shall assure that the Request For Proposals (RFP), contract, and/or work authorizations have the following requirements of the contractor:

- GWUT Procedure Submittal
- Personnel qualification requirements and documentation submittal
- Equipment type requirements/specifications
- Equipment condition tests
- Equipment maintenance and calibration requirements and records

4.2.2 GWUT RFP Technical Requirements

The RFP of GWUT services will include the technical requirements for the documents that the contractor submits for review with their proposal as well as testing requirements and activities while on site.

4.2.3 GWUT Contractor Procedure Review

Contractors shall submit written inspection procedures to the PM for review and acceptance prior to performing any inspections in the field. The procedures submitted by contractors must address the requirements of this section in their procedures or describe why a step, if it is omitted, is not applicable to their procedure. The procedure shall reference the version of the equipment software used. Only the latest version issued by the manufacturer of the GWUT equipment will be acceptable.

The PM shall review the GWUT Contractor's procedure(s) for the following items.

4.2.3.1 Numbering

The procedure shall have a unique alphanumeric number assigned to it with a revision number and date.

4.2.3.2 General Description

The procedure should describe the scope and the general theory regarding how GWUT works, what it measures, and what it is capable of detecting.

4.2.3.3 Limitations

The procedure must describe where GWUT should not be used and what it cannot detect with the contractor's specific equipment and test procedures.

4.2.3.4 Instrumentation

The procedure shall list all equipment by name and model number that is allowed for the inspection. Any equipment not included on this list must be separately and specifically accepted by the PM prior to its use.

4.2.3.5 Personnel Qualifications

Documentation shall list all personnel conducting the inspection, qualification requirements of each position, and compliance of personnel with qualification requirements including how the personnel were trained on the specific procedure. Minimum qualification requirements are specified in Section 4.2.5 of this Procedure.

4.2.3.6 Step-by-step Instructions

The procedure shall have specific step-by-step instructions containing the following details as a minimum:

- Selection criteria and guidance on transducer collar location and placement;
- Establishment of a reference location or datum that the transducer collar is located from;
- Pipe surface preparation requirements;
- Transducer collar installation requirements and checks;
- Collar, guided wave generator, and laptop connection requirements;
- Establishment and photographic documentation of collar orientation (positive/negative directions);
- System check including channel and balance checks;

- Shot documentation requirements including shot number, datum location and direction, and system or location identification;
- Shot setup criteria / instructions including frequency selection, length of shot, level of attenuation, and data averaging;
- Process of identifying known features;
- Instructions for setting the Distance Amplitude Curves (DAC);
- Identification of non-manmade features such as wall loss;
- Method of determining distance of shot at a given sensitivity;
- Method of estimating wall loss;
- Method of comparing known feature(s) to verify system performance; and
- Process of overlaying and aligning indications from different shots.

4.2.3.7 Preparation and Approval

The procedure shall document the person who prepared it and the date it was prepared. It shall have been reviewed and approved by a responsible person in the organization that issued it. This person shall be *Certified GUL Level II.* Both of the above requirements shall be indicated by signatures and dates. The PM shall record comments from the procedure review on **Form C: GWUT Inspection Procedure Review**.

4.2.4 Inspection Equipment

The PM shall assure that the contractor's equipment complies with the following sections. The verification of the equipment type and condition will occur in the field at the test site.

If the equipment does NOT meet the following requirements but is acceptable to the PM it shall be documented by the exception process outlined in Section 11 of this procedure.

4.2.4.1 Equipment Type

The PM shall assure that the latest generation GWUT device is being used, either third generation GUL equipment (G3) or a later version.

4.2.4.2 Software Version

Only the latest software shall be used (currently Version 3). Contractor shall provide documentation that the latest software is being used. The PM shall assure that the latest software is being used and record the manufacturer, type and serial numbers of the relevant equipment.

4.2.4.3 Equipment Maintenance and Calibration

The contractor shall produce evidence that periodic factory maintenance or calibration has been conducted in compliance with the manufacturer's and the contractor's QA procedures. The contractor shall produce evidence that the equipment has been calibrated within the last 12 months per the manufacturer's specifications.

4.2.4.4 Equipment Condition

Inspection equipment shall be maintained in good working order. The PM shall assure that provisions in the contract work authorization provide the Company the right, upon request, for inspection personnel to demonstrate that the transducer modules pass a capacitance check, and that there are no "open" or "short" conditions in modules, cables, or other equipment. The observation of these tests will be required in the inspection phase of this procedure.

4.2.5 Qualifications of Inspectors

4.2.5.1 Training

The PM shall assure that inspection personnel **DP** (including personnel who operate guided wave inspection equipment and personnel who interpret inspection data) shall have a minimum of 40 hours of documented training provided by an instructor accredited by the equipment manufacturer and have GUL Level I certification. GUL certification requires a knowledge of equipment operation, testing procedures, frequency determination, field data collection, conversion of guided wave data into pipe features, estimation of metal loss (estimated cross-sectional area loss and circumferential extent), and data interpretation of anomaly features on cased and buried pipe. Personnel shall provide evidence of successful completion of certification tests related to the training.

4.2.5.2 Experience

In addition, inspection personnel **DP** shall have experience inspecting pipe segments similar to those to be inspected. They shall submit inspection data and the corresponding interpretation from one or more shots for review by the PM prior to inspecting pipeline segments. At least one shot shall be of a pipe with heavy bitumastic coating and at least one shot shall show a metal loss feature for which the size has been estimated.

4.2.5.3 Operator Qualification Requirements (OQ)

Inspection personnel **DP** shall meet the requirements of the Company's OQ program.

4.2.6 Quality Assurance

Inspection contractor shall have quality assurance procedure in place that requires that a GUL Level II inspector (or equivalently certified Senior Level equipment operator with pipeline and casing experience) reviews each shot, approves reports and ensures that the GWUT operator is qualified.

5.0 INSPECTION

5.1 Excavation

5.1.1 Size of Excavation

The excavation shall expose, and the coating shall be removed on, at least ten feet of pipe being assessed. If this is not possible the PM shall document the justification and authorization by the Exception process outlined in Section 11 of this procedure.

5.1.2 Excavation Procedure

The pipe shall be excavated in accordance with Company's procedure for pipe excavation.

5.2 Pre-GWUT Activities

The PM shall assure that the following tasks are performed prior to the GWUT inspection.

5.2.1 Visual Pipe Inspection

The PM shall assure that the following inspections occur in accordance with the requirements of GAS STANDARD **167.0211,** *Bell Hole Inspection Data Requirements* or in accordance with the procedures of the third party inspection contractor.

5.2.2 Casing End Seal Removal

SoCalGas personnel should remove the end seal from the casing at each GWUT test location to facilitate limited visual inspection. They shall observe and collect the corrosion data, if found, under the end seal, in order to verify GWUT findings.

5.2.3 Coating Removal

Coatings shall be removed and the pipe surface prepared in accordance with the inspection company's accepted procedures. When practicable, consideration should be given to removing as much as 10 feet of coating for GWUT inspections.

Epoxy type coatings (i.e., FBE) generally do not need to be removed from the pipe as the transducer collar can transmit sound through these types of thin film coatings.

5.2.4 Identification and Marking of Carrier Pipe

The PM shall assure that the carrier pipe is physically marked and photographed with the following information:

- Pipe number

- Assumed direction of gas flow[3]

5.3 GWUT Inspection Locations

The PM has the responsibility to assure that the following tasks are performed. Company or contract personnel may perform the tasks as directed by the PM or as specified below.

5.3.1 GWUT Location Selection

5.3.1.2 Selection

At each inspection location, the **DP** shall select and mark two locations where GWUT shots will be taken. The **DP** shall use his or her experience in selecting the best locations. The selection criteria shall be identified in accepted procedures prior to inspection.

5.3.2.1 Marking

The following data shall either be marked with a grease pen on the pipe surface or written on a removable writing surface. This data shall appear in photographs of the collar on the pipe at each location.

1. Shot number
2. Location of the collar (i.e. dig site and/or chainage)
3. Assumed direction of flow

If using a grease pen directly on the pipe, this step can be deferred until after the B-Scan wall thickness measurements described in the following paragraph are completed.

5.4 B-Scan Wall Thickness Testing

B-Scan testing is performed to detect any interior wall loss or pitting in the vicinity of the transducer collar and to provide complete inspection within the Dead Zone and Near Field. This is important for two reasons: a) because the GWUT does not assess the pipe effectively in the Dead Zone and Near Field, and b) because the thickness of the pipe in this location is used in calculating estimated remaining wall thickness at indications. The length of the Dead Zone and Near Field for each inspection must be recorded.

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[3] This is for convention purposes and only aides in the alignment of data. Actual gas flow direction does not affect the testing.

5.4.1 Test Technique

B-Scan is a semi-automated technique in that the pipe surface is manually scanned with an ultrasonic transducer with a distance encoder. This provides a relatively rapid and continuous examination of the interior surface. A straight beam point-by-point technique can be substituted for the B-Scan technique.

5.4.2 Test Location

The pipe thickness shall be scanned in each quadrant (top, bottom, and sides) at each shot location for an axial distance for at least two feet[4] from the center line of the collar. The **DP** must ensure that the entire Dead Zone and Near Field is covered by the B-Scan test area.

5.4.3 Recorded Data

The nominal and minimum wall thickness shall be recorded for each quadrant. The side quadrants shall be identified by clock position or geographically (i.e. north, south, east, or west). The contractor may use their own forms or SoCalGas forms to document the readings.

5.5 GWUT Test Setup

5.5.1 Collar Positioning

The transducer collar shall be placed at the test location. The positive direction of the collar shall be pointing in the direction of assumed gas flow. The collar shall be oriented perpendicular to the pipe axis as closely as possible.

For casing shots, the collar must be positioned such that the Dead Zone and Near Field do not extend into the casing. If that is impractical, another shot may be taken from a different location to assess the Dead Zone and Near Fields of the first shot.

5.5.2 Transducer Coupling

5.5.2.1 Rigid Collar

If a rigid collar is used it shall be clamped tightly onto the pipe per approved procedures. The **DP** shall check to assure that all the transducer screws are loose to assure that the transducers are uniformly coupled to the pipe.

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[4] Dead Zone widths were measured for pipe diameters from 2 inch to 30 inches at the minimum frequency available for each pipe diameter. Dead zone widths ranged from 26 to 36 inches. 48 inches exceeds the largest Dead Zone width generated by the GUL equipment.

5.5.2.2 Inflatable Collar

If an inflatable collar is used the collar shall be partially inflated. The **DP** shall assure that the transducer modules are properly aligned to the pipe surface and are in contact with the pipe surface.

5.5.2.3 Inflation of Collar

If an inflatable collar is used then the **DP** shall inflate it to the manufacturer's recommended pressure (typically 20 to 35 PSI) as identified in approved procedures.

5.6 Taking the Shot

5.6.1 Data Input

The **DP** shall input the following information into the GWUT software:

5.6.1.1 Site

The name of the site. This will include the line number, approximate Mile Point or stationing.

5.6.1.2 Pipe Diameter

Outside diameter of the pipe shall be the same as the diameter of the collar that is recognized by the computer.

5.6.1.3 Datum

The reference location from which the collar and indications will be measured.

5.6.1.4 Distance

The distance in feet and inches from the center of the transducer collar to the datum shall be recorded. If the datum is in the positive direction then the distance shall be recorded as a positive distance. If the datum is in the negative direction then it shall be recorded as a negative distance.

5.6.1.5 Range

The maximum distance achieved during the shot and set by the computer shall be at least the range specified during the pre-assessment.

5.6.1.6 Notes & Operator Comments

Notes or comments that the operator wants to be recorded shall be completed in the fields provided in the software.

5.6.2 Capacitance Check

For the first test at each location the **DP** shall conduct capacitance and coupling checks to assure that collar and the cables do not have electrical faults and that the transducers are properly coupled to the pipe. The capacitance check provides a quick method of detecting faults that would later corrupt the data.

5.6.2.1 Method

The **DP** shall rub or tap the pipe and view the response from the transducer. The response shall be relatively the same for each segment. Figure 5.1 shows a sample of the response from the transducers with channel A1 being low. If the response is not similar on all the channels the **DP** shall trouble shoot the collar and cables to correct the problem before taking the shot.

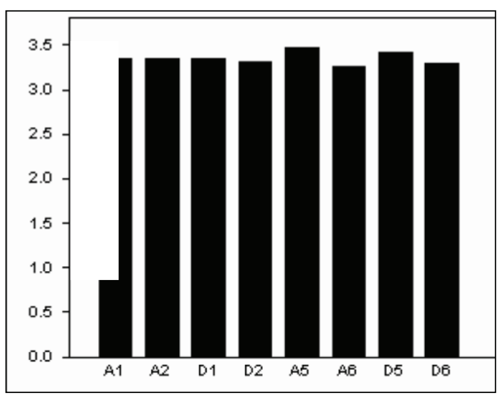


Figure 5.1: Capacitance check of transducers showing that A1 is out of range

5.6.3 Acquiring the Shot

The **DP** shall have the computer acquire the shot. During the shot no work shall be performed on the pipe that may induce acoustic noise into the pipe section being tested. Activities such as grinding, welding, removal of coating, and sand blasting can reduce the range of the shot.

5.7 Analysis

5.7.1 Location of Analysis

The analysis of the test shall be performed on-site at the time of the testing. This is to ensure that features can be identified, wall loss proven-up, and the test retaken if necessary. The test can be reviewed and reanalyzed offsite but only after a thorough on-site analysis.

5.7.2 Transducer Collar Check

The following characteristics of the raw data shall be checked:

5.7.2.1 Amplitude Balance

Figure 5.2 shows the amplitude balance for all the segments. The amplitude compensation for all segments should have values between 0.5 and 1.5. If any segments are outside of this range the collar shall be reattached and the test retaken.

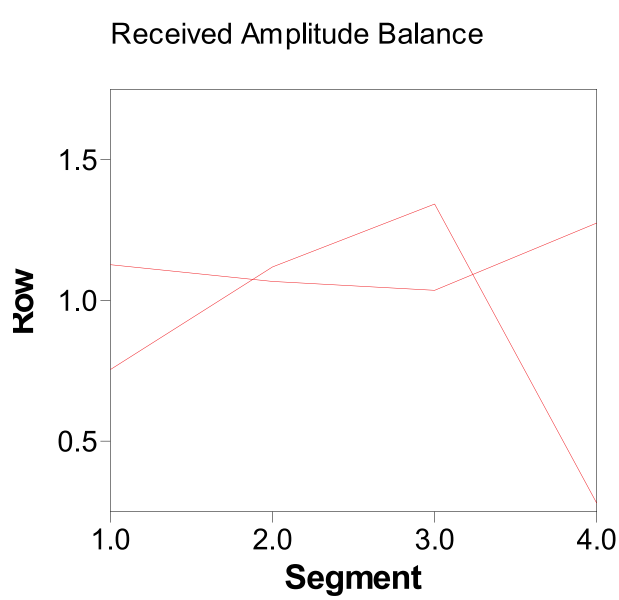


Figure 5.2: Amplitude balance chart showing that segment 4.0 is out of range

5.7.2.2 Raw Data

Figure 5.3 shows the raw voltage for all channels. The raw data of each test shall be reviewed by the **DP**. If any voltage level is significantly different than the others the **DP** shall troubleshoot the problem and re-perform the test.

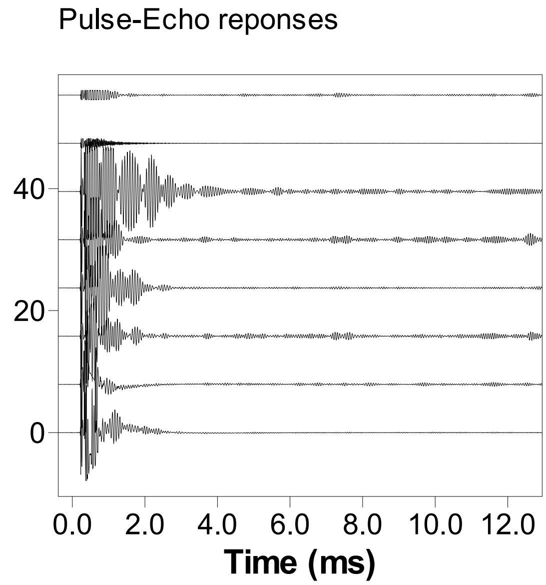


Figure 5.3: Raw data chart showing unequal response at various voltages

5.7.2.3 Capacitance Check

The **DP** shall check the capacitance of the collar after the shot is taken to make sure all segments have similar capacitance levels. This check is similar to that specified in section 5.6.2 except that it is taken after the shot and is a measure of the capacitance levels during the shot. If the capacitance is low on one segment adjustments shall be made and the test retaken. Figure 5.4 shows the capacitance chart with Segment 4 too low.

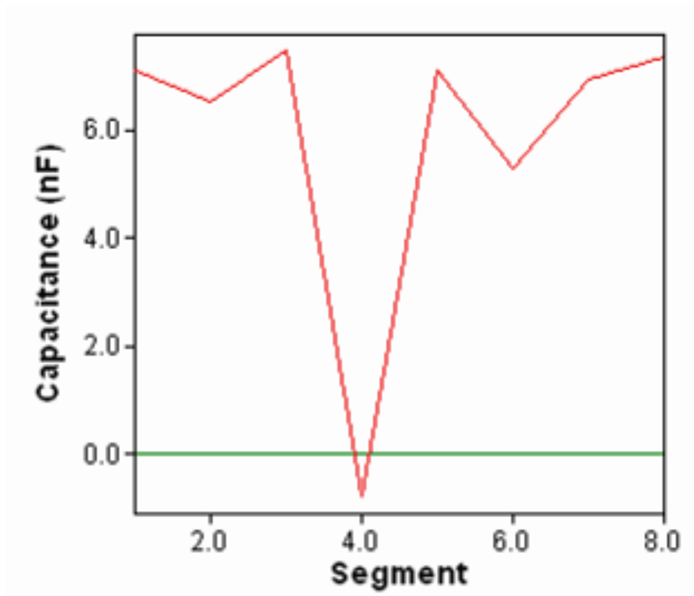


Figure 5.4: Capacitance chart showing that the capacitance on Segment 4 is too low

5.7.2.4 Documentation

The PM shall review the results of these on-site diagnostics (amplitude balance, voltage per channel, capacitance). Where on site diagnostics show some discrepancies with the manufacturer's requirements and specifications, the testing shall cease until the equipment can be restored to manufacturer's specifications.

5.7.3 Initial Analysis Steps

The **DP** shall perform the following steps to analyze the test results;

5.7.3.1 Identification of Known Pipe Features

The **DP** shall identify on the test scan known pipe features such as welds, bends, and entrances into soil and casing.

5.7.3.2 Review of Shot at Various Frequencies

Each shot shall be reviewed at various frequencies (at least 3) to assist in the analysis of the shot and the optimal frequency to display the shot. The interpolated frequency function on the G3 shall be used. The range of frequencies utilized shall be documented. *Note: In many cases there is not a single optimal frequency and the analysis of features is performed reviewing their response at varying frequency.*

5.7.3.3 Setting of the DAC

The weld Distance Amplitude Curves (DAC) shall be set for each inspection based on known features of the pipeline. Changes in attenuation rates caused by features, coatings, and entering soil shall be accounted for in developing and setting the DACs. Accessible welds, along or outside the pipe segment to be inspected, are used in setting the DAC curve. A weld(s) in the access hole (secondary area) is an alternative to set the DAC curve. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. Having a weld, in the near field or dead zone, between the transducer collar and the calibration weld is not permitted. If the coating is removed from the weld prior to the inspection then the expected attenuation has been changed. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible or version 3 software is being used. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating if it is impractical to set the DAC curve on the segment being inspected. If the actual cap height is different from the assumed cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve may be required. Actual weld cap heights, if measured, shall be recorded. Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.

5.7.3.4 Signal to Noise Ratio

To ensure that the entire pipeline segment is assessed there must be at least a 2 to 1 signal to noise ratio for the required wall loss anomalies to be detected, across the entire pipeline segment that is inspected. This may require multiple GWUT shots.

5.7.3.5 Length of Shot

The end of the shot is the point where the Signal-to-Noise Ratio (SNR) dips below the required ratio of 2:1. The **DP** shall provide a screen shot of the test that shows the "Call" and "Noise" DACs running into the background noise. This screen shot shall be used to determine the length of the shot. A logarithmic vertical axis scale is preferred for this analysis, but not required. Examples are shown in Figures 5.5 and 5.6.

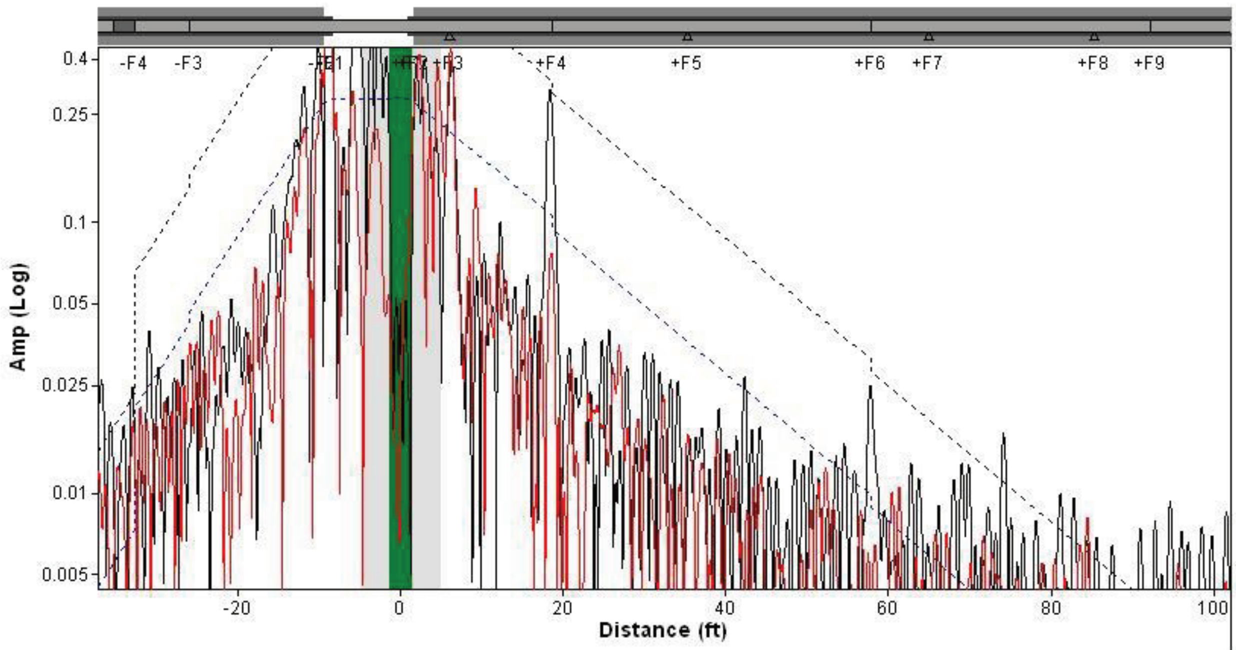


Figure 5.5: GWUT scan with log scale used to determine length of shot

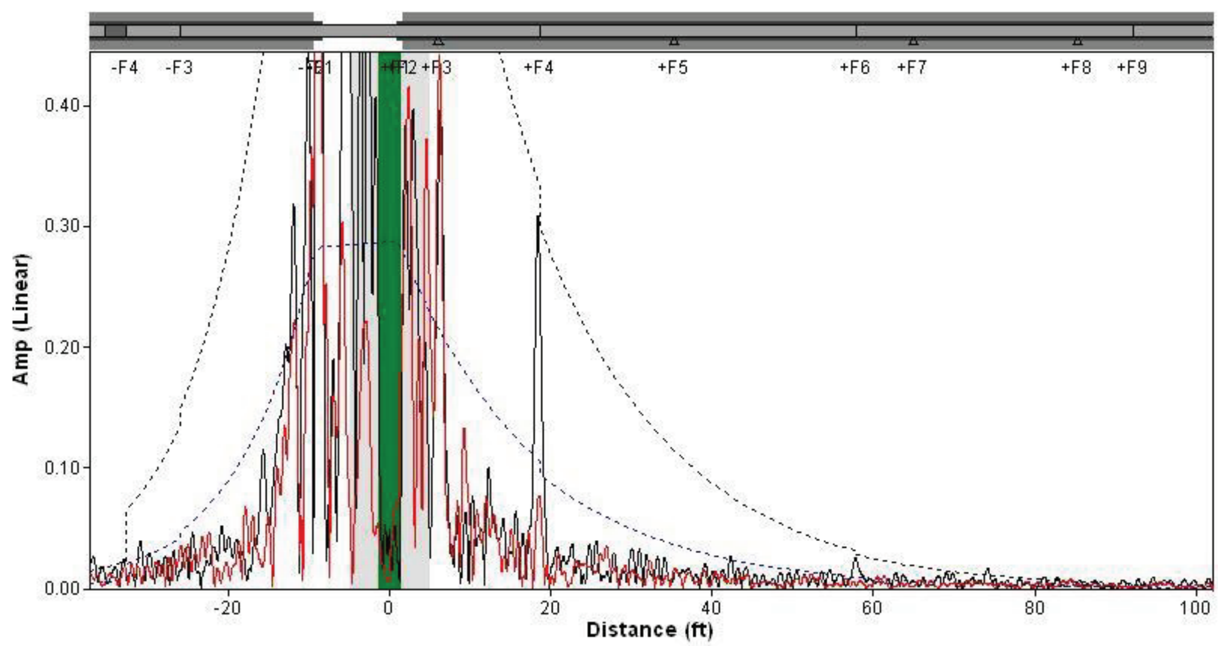


Figure 5.6: GWUT scan with linear scale used to determine length of shot

The "Noise" DAC should be half the height of the "Call" DAC. The shot length is determined by the point where the Noise DAC intersects the general noise level or "noise floor." For example, if the minimum sensitivity is established at 5% CSA, the range can be calculated by observing the point where a "noise DAC" set at 2.5% CSA hits the noise floor. In Figures 5.5 and 5.6, this occurs at about 50 feet.

For casings, a sensitivity of less than or equal to 5% CSA must be achieved at the maximum inspection range.

5.7.3.6 Overlap of indication for Casings

Casings shall be shot from both ends. These two inspections are to be overlaid to show the minimum 2 to 1 SNR is met in the middle. If possible, show the same near or midpoint feature (if present) from both sides. If the required sensitivity cannot be met for the entire length of the casing, use of GWUT is not feasible and another inspection method must be used.

5.7.3.7 Shorted Casing

If the GWUT operator sees any evidence of interference other than some slight dampening of the GWUT signal from a shorted casing, the short must be cleared prior to the use of GWUT as 'other' technology.

5.7.3.8 Identification of wall loss features

The **DP** shall identify features of potential wall loss on the scan of the test. The **DP** shall determine whether the signal response is representative of metal loss. The **DP** shall describe the type of feature if it is not representative of metal loss.

5.7.3.9 Identification of Verification Indication

The **DP** shall identify a feature(s) that can be used to verify that the test technique is adequate.

5.7.4 Weld Size Calculation

The PM shall calculate the estimated cross sectional area change of the weld using the following equation:

$$\%ECLWeld = \frac{WD^2 - OD^2}{OD^2 - ID^2}$$

Where:

%ECLWeld = % of cross sectional change from weld crown
WD = Weld Crown Diameter = OD + 2(weld crown height)

OD = Outside pipe diameter
ID = Inside pipe diameter

5.7.4.1 Documentation

The PM shall document the estimated cross sectional change of the weld.

5.7.4.2 No Weld Present

If no weld is present to measure the crown height then the PM shall document such and assume a weld cap height that is the maximum acceptable API 1104 weld cap height of 1/8 inch.

5.7.5 Sensitivity Determination

5.7.5.1 Measurements

The distance where the following sensitivities are achieved shall be recorded.

- 3%
- 4%
- 5%
- Calculated required sensitivity
- Sensitivity at the end of shot

5.7.5.2 Acceptance Evaluation

The PM shall compare the measured sensitivity at the end of the range of the inspection to the specified sensitivity identified in Section 3.6 of this procedure. If the sensitivity does not meet the required value then that length of pipe has not been considered assessed and another technique must be used.

5.7.6 Sizing of Wall Loss Features

5.7.6.1 Estimate dimensions

The **DP** shall provide an estimate of the location and dimensions (depth, axial length, circumferential width) for all metal loss features above the sensitivity requirement. The inspection contractor will provide a written description of how the dimensional estimates are determined. The latest version of test equipment manufacturer's algorithms shall be used. This documentation shall be provided to SoCalGas in the final report.

5.7.6.2 Estimation of Wall Loss in Near Field

While the receiving amplifiers are coming up to full power, the size of features detected may be inaccurate. The affected area on the pipe is called the near field. Features in the Near Field shall have an added 20% increase to the axi-symmetric and non-axi-symmetric responses for conservatism in sizing. Alternatively, they can be physically proven up with B-Scan.

5.7.6.3 B-Scan or Straight Beam Sizing

If the features are accessible, detected wall loss shall be measured with B-Scan, straight beam ultrasonics and/or a pit depth gauge. Casings have a more involved verification system, described in sections 7 and 8.

5.7.6.4 Estimated Cross Sectional Area Wall Loss

The **DP** shall provide the PM the estimated cross sectional area change for all areas of wall loss. This shall be based off of the default weld cross sectional area change of 25%.

5.7.6.5 Circumferential Extent

The **DP** shall provide the PM the estimated circumferential extent of each wall loss area.

5.7.6.6 Documentation

The estimates of wall loss shall be documented.

5.7.6.7 Calculation

The PM shall calculate the estimated wall loss utilizing the following formula:

$$Est.\%WallLoss = \frac{ECL}{CE} \times \frac{\%CSCWeld}{25\%}$$

Where:
Est.%WallLoss = Estimated % wall loss
ECL = Estimated cross sectional area loss in percent
CE = Circumferential extent in percent
%CSCWeld = Measured % cross sectional change of weld

This calculation shall be shown.

5.7.6.8 Accuracy of sizing

The inspection contractor shall provide an estimate of the tolerances applicable to metal loss feature dimensions.

5.7.7 Reporting Requirements

Form D functions as a Preliminary Report and is to be completed the day of the inspection.

Final reports from the inspection contractor are to be issued to the Project Manager within 30 days of the inspection. The Final Report should include summaries of methods used and inspection findings as well as all raw data and applicable charts, drawings, etc. developed during the course of the inspection. The Final Report shall be provided in both hardcopy and electronic formats

6.0 PRIORITIZATION OF THE SITE AND RESPONSE – CASED PIPE

6.1 Objectives

The objective of this section is to identify the appropriate response to indications and establish the urgency of action. When possible, indications may be verified as per Sections 8.4 through 8.6.

IMPORTANT: This section applies only to cased pipe, when utilizing the GWUT technology as a stand-alone 'other technology'. See Section 7 and 8 for the non-cased segment classification and verification process.

6.2 Indications on Pipe inside Casings

All indications of wall loss greater than 5% CSA on pipe within a casing shall be directly examined prior to completing the integrity assessment on the cased carrier pipe. As described in Table 6.1 below, the maximum time frame for each is 6 months for those pipelines operating at greater than 30% SMYS and 12 months for those operating at or below 30% SMYS. For those locations where the operating pressure is greater than 50% SMYS, the pressure must be reduced to 80% of the operating pressure at the time the indication is "discovered" by the GWUT. For those locations where the operating pressure is greater than 30% and less than or equal to 50% SMYS, then the operating pressure shall not exceed the operating pressure at the time of the "discovery" of the indication and the monthly leak survey shall be performed until the indication is directly examined. For those locations where the operating pressure is less than or equal to 30% of SMYS, the casings must be leak surveyed once a month until the indication is directly examined.

Table 6.1: Prescriptive Plan for GWUT Indications within Casings

GWUT Criterion	Less than 30%	Over 30 to 50% SMYS	Over 50% SMYS
Over 5% CSA and identified for examination	Interval < 12 month	Interval < 6 months	Interval < 6 months
	Leak survey once per month	Direct Examination	Direct Examination
	Direct Examination	MOP<psi @ discovery	Reduce to 80% MOP @ discovery
		Leak survey once per month	

7.0 CLASSIFICATION OF INDICATIONS – NON CASING APPLICATIONS

7.1 Overview

GWUT for non-casing applications may be used in conjunction with, and in addition to, a primary assessment method such as ECDA or ICDA. GWUT is not to be used as the primary assessment method for non-casing applications. This section of the procedure is therefore optional and provides guidance on the classifications of GWUT indications through the integration of percent SMYS, class, estimated wall loss, and remaining strength evaluation. The following sections provide the steps in conducting this prioritization. Note: this process is not necessary for cased segments. All indications on cased segments must be directly examined (see Section 6.0).

7.1.1 Process Flow

Figure 7.1 illustrates the process flow chart showing the steps of determining the classification of the indications.

7.2 Responsibility

The PM is responsible for determining the classification of the indications. The PM may delegate the tasks to a competent person but should review and approve all results.

7.3 Determining Indication Length

7.3.1 Initial Length Determination

For purposes of the classification process the PM will assume the indications identified in Section 5.7.6 are longitudinal flaws in accordance with:

$$LongFlaw(inches) \geq \sqrt{20 * D * t}$$

Where:

LongFlaw (inches) = The length where greater flaw lengths do not further reduce
predicted burst pressure when evaluated using B31G.

D = Outside diameter in inches

t = Nominal wall thickness in inches

When the remaining strength is evaluated using the B31G-modified or Effective Area method, the flaw length shall be assumed to be 7 x LongFlaw. Both are conservative assumptions in that the actual flaw lengths may be substantially shorter allowing for higher burst pressures.

7.3.2 Other Methods of Determining Axial Length

The PM may use other methods to determine alternative lengths of the indications. If other methods are used they shall be documented.

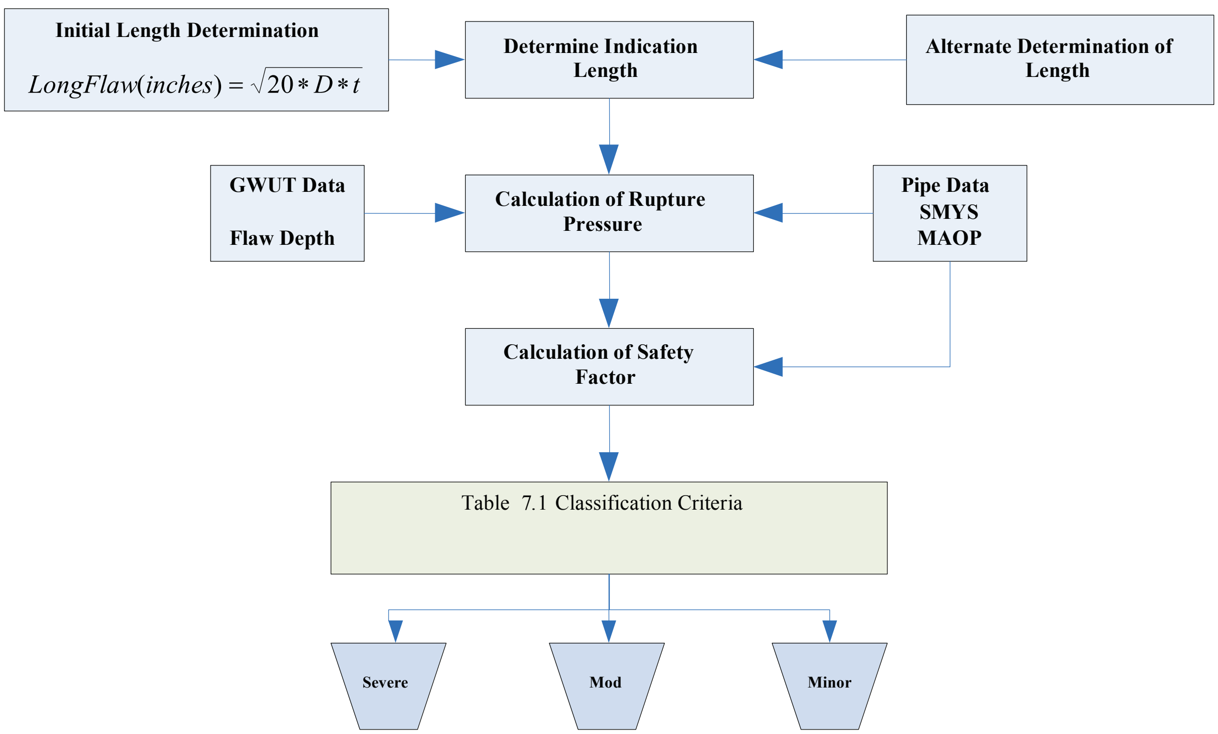


Figure 7.1: Classification Process Flow Diagram

7.4 Calculation of Burst Pressure

7.4.1 Rupture Calculation

The PM may calculate the predicted burst pressure utilizing RSTRENG or equivalent other method for all reported indications from the GWUT inspection (see GAS STANDARD 182.0050 *MAOP Evaluation of Corroded Pipe* for guidance regarding the applicability of RSTRENG and KAPA).

7.4.2 Rupture Calculation Inputs

The following inputs may be used for the calculation of the predicted burst pressure.

- Est. % Wall Loss (or flaw depth = Est. % Wall Loss X specified minimum wall thickness)
- SMYS: Specified minimum yield strength
- Flaw Length: Flaw length calculated in Section 7.3.1 or 7.3.2

7.4.3 Documentation

The $\boxed{\text{PM}}$ should document the inputs and calculation results.

7.5 Classification of Indications

The $\boxed{\text{PM}}$ should classify all the indications reported from the GWUT inspection.

7.5.1 Safety Factor

The safety factor should be determined for each reported indication utilizing the following formulation:

$$SF = \frac{Pf}{MAOP}$$

Where:
SF = Safety Factor based on predicted burst pressure
Pf = Predicted burst pressure
MAOP = Maximum Allowable Operating Pressure

7.5.2 Classification of Indications

The indications may be classified in accordance with Table 7.1 as a function of operating stress level. The classification should be documented.

Table 7.1: Classification Criteria of GWUT Indications

Classification	**Pipeline Stress Level at MAOP**		
	At or above 50% SMYS	**At or above 30% but less than 50% SMYS**	**Less than 30% SMYS**
Severe	Mechanical damage[5] or $SF \leq 1.25$	Mechanical damage or $SF \leq 1.4$	Mechanical damage or $SF \leq 1.7$
Moderate	$1.25 < SF \leq 1.39$	$1.4 < SF \leq 1.7$	$1.7 < SF \leq 2.2$
Minor	$SF > 1.39$	$SF > 1.7$	$SF > 2.2$

[5] Guided wave UT inspection technology is generally unable to determine the size of dents or to reliably determine if metal loss is present in the dent. Therefore, all features characterized as “mechanical damage” shall be assigned a “severe” classification.

8.0 VERIFICATION AND DIRECT EXAMINATION

8.1 Objective

This section describes the optional process that may be used to validate the results of a GWUT assessment by use of one or more methods and the inspection of any anomalies. The methods primarily consist of direct examination of an exposed pipe surface, by verifying the location and the axial symmetric amplitude. Comparison of the guided wave inspection results with pipeline features that have been previously characterized in detail using ILI or other quantitative inspection methods may also be used. When indications are found in cased segments, see Section 6.0 for additional guidance.

8.2 Verification Flow Chart

Figure 8.1 shows the process flow of the verification procedure.

8.3 Number of Locations

On cased segments, all indications above 5% CSA must be verified by direct examination. Otherwise, a minimum of two indications or features for each pipe segment being assessed may be verified through direct visual examination.

8.3.1 Severe Indications

All indications identified as severe may be verified through direct examination or other complimentary quantitative technique.

8.3.2 Moderate Indications

All indications identified as moderate may be verified through direct examination or other complimentary quantitative technique.

8.3.3 Minor Indications

8.3.3.1 Minor Indications with Severe and/or Moderate Indications

If severe and/or moderate indications are successfully verified then minor indications do not need to be verified.

8.3.3.2 Minor indications with No Severe or Moderate Indications

If no severe or moderate indications are identified then the GWUT Project PM Coordinator may select at least two minor indications to verify.

8.3.3.3 No Indications

If no indications are reported then the GWUT Project Coordinator $\boxed{\text{PM}}$ may select two locations to verify the inspection. One of the locations can be at the section of pipe where the coating was removed for the GWUT inspection. The other location may be a feature such as a weld.

8.3.3.4 Indications that are Reprioritized to Higher Severity

At least four minor indications may be verified when the pipe segment where Indications are found to be prioritized as more severe than the initially priority. If any two of the minor indications are found to be a higher priority than the initial priority then all wall loss indications may be verified.

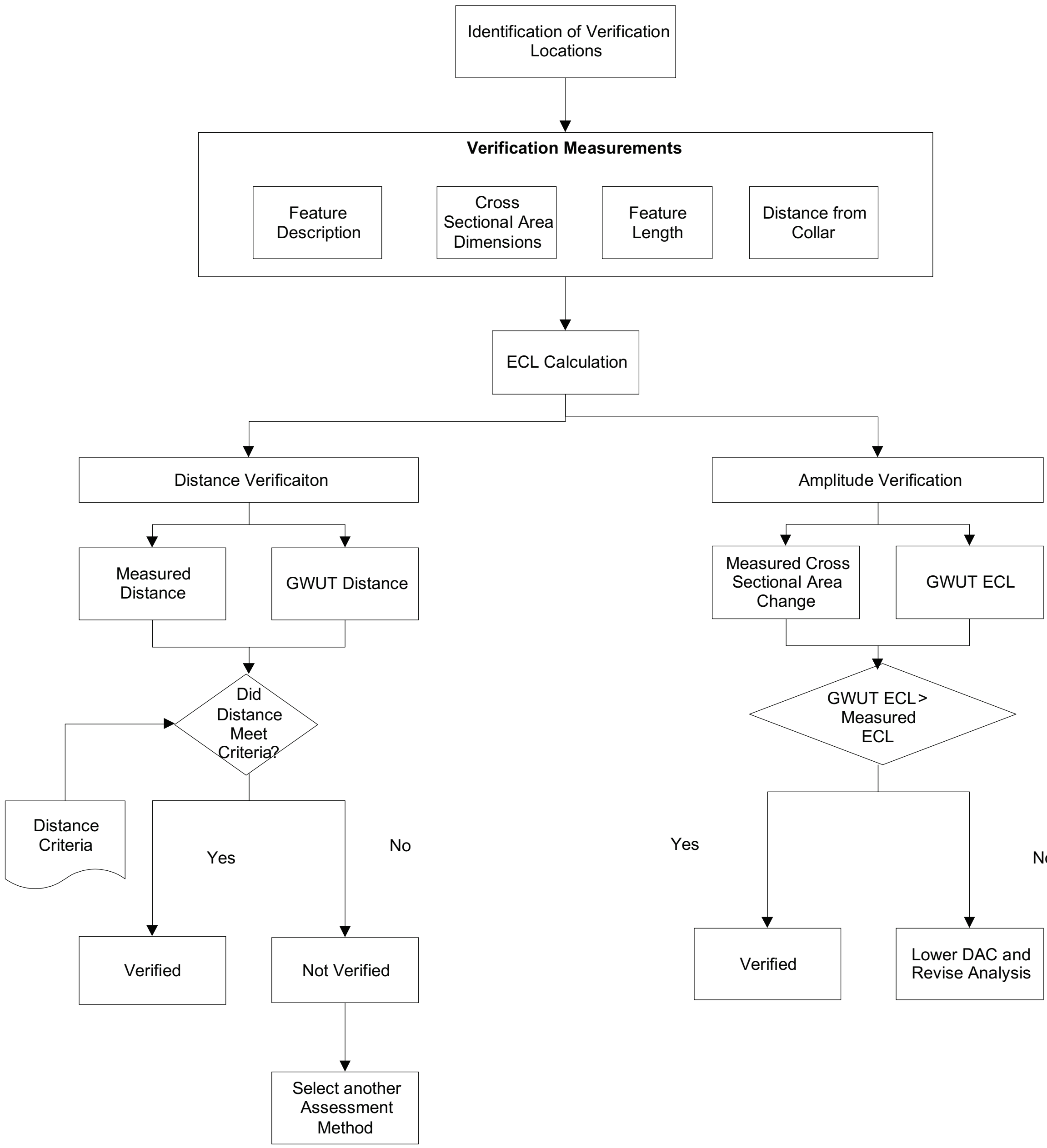


Figure 8.1: Verification flow chart

8.3.4 Responsibility

The PM, working with the **DP** may select the features for verification.

8.4 Verification Measurements

The PM should document the following.

8.4.1 Feature Type Description

A detailed description of the type of feature or indication.

8.4.2 Feature Dimensions for Cross Sectional Area Calculation

Sufficient dimensions may be measured and documented to estimate the cross sectional area change the feature represents. The feature can represent either an increase or decrease in cross sectional area.

8.4.3 Feature Length

The length of the feature may be measured and documented.

8.4.4 Distance from Transducer Collar

The distance from the transducer collar may be physically measured and documented. If the feature is past a bend, measure the outside distance around the bend.

8.5 Estimated Cross Sectional Area Loss (ECL) Calculation

8.5.1 Calculation

The ECL may be calculated using the following formulation:

$$\%ECL = \frac{Radial\Delta * circumferentiallength}{\frac{\pi}{4}(OD^2 - ID^2)}$$

8.5.2 Documentation

The results of the calculation should be documented.

8.6 Verification Process

The distance and amplitude observed with GWUT may be compared with the measured distance and calculated amplitude of the physical indication.

8.6.1 Distance Verification

The PM may compare and record the difference in the physical distance with the observed GWUT distance.

8.6.2 Acceptance Criterion

The difference in distance between measured and GWUT observed data may be considered acceptable if it is less than the distance calculated below:

$$Critieria(inches) = 0.5inches/_{foot} * dist(feet)$$

8.6.3 Lack of Verification

If the actual distance of the indication is not within the tolerance criteria described above, the indication did not verify the GWUT tests. The PM should document the findings and may select another verification indication or consider another method to assess the pipe segment.

8.6.4 Axial Symmetric Amplitude Verification

The original DAC is set based on weld cap height. The DAC may need to be adjusted if it is found to be un-conservative during verification activities. If the GWUT ECL is greater than the actual measurement then no action is necessary. If the GWUT ECL is less than the measured ECL then the GWUT Coordinator may lower the DAC until the GWUT ECL is equal to the measured ECL. There may be signals in the shot that were previously below the call DAC but are above the new, lower call DAC. If that is the case, analysis may be repeated at Section 5.7.3.4. The PM should document this activity and the adjusted ECL.

9.0 PRIORITIZATION AND RESPONSE – NON-CASING APPLICATIONS

9.1 Objective

GWUT for non-casing applications may be used in conjunction with, and in addition to, a primary assessment method such as ECDA or ICDA.GWUT is not to be used as the primary assessment method for non-casing applications. This section of the procedure is therefore optional and integrates related pre-assessment and GWUT data to help determine the prioritization (Immediate, Scheduled, and Monitored) of the condition of the inspected pipe section. Note: this process is not necessary for cased segments.

9.2 Urgency Criteria

Table 9.1 defines the Urgency Criteria. The level of urgency (A, B, or C) is defined as having one or more criteria met for any given level. Level A is the most urgent level.

Table 9.1: Urgency Criteria[1]

Level	History of Leaks (yes/no)	Years w/o CP	Instant Off of pipe adjacent to casing (absolute mV)
A	Yes	>4	< 600 mV
B	No	1< Years ≤ 4	600 ≤ mV < 850
C	No	≤ 1	≥ 850

[1]A level of urgency is determined by having one or more criteria met in any given row.

9.2.1 Level A

The ECDA or ICDA region where the inspected pipe section is located has had a history of leaks or ruptures due to external or internal corrosion or has had a metallic short or has not had cathodic protection for a cumulative length greater than four years or an instant off polarization level less than 600 mV (absolute) on the pipe segment near a casing.

9.2.2 Level B

The inspected pipe section has had no cathodic protection for more than one but less than or equal to 4 years, or an instant off polarization level between 600 mV to less than 850 mV (absolute) on the pipe segment near the casing.

9.2.3 Level C

The pipe segment has had no leaks or ruptures, has not had a metallic short, has not been without CP for one year or longer and has instant off polarization of greater than or equal to 850 mV.

9.3 Prioritization of Excavations

The classification of indications may be integrated with the urgency criteria to prioritize the inspected piping and response to conditions. This integration and prioritization may be performed in accordance with Table 9.2.

Table 9.2: Prioritization of Pipe Sections

Classification Level	Urgency Level		
	Level A	**Level B**	**Level C**
Severe	Immediate	Immediate	Immediate
Moderate	Immediate	Scheduled	Monitored
Minor	Scheduled	Monitored	Monitored

9.4 Response to Prioritized Indications

9.4.1 Responsibility

The type of response is dependent upon the prioritization of the indication. The PM may determine the response in accordance with the following sections and document the recommended response.

9.4.2 Response to Immediate Indications

The response for immediate indications may occur no later than 60 days from the assessment date. Immediate indications may be responded to by either a reassessment with another method or by reducing the stress through pressure reduction or remediation of the indication. These actions are further described below:

9.4.2.1 Reassessment

Reassessment of pipe segment with pressure test to demonstrate acceptable pressure retaining capacity of the pipe, or

Reassessment with ILI or direct examination of the pipe surface to verify flaw dimensions,

-Or-

9.4.2.2 **Reduction of Stress**

- Pressure reduction to 80% of the operating pressure present at the time that the defect was detected. The pressure should be reduced within five days of the time that the defect was discovered, or

- Removal from service, or

- Repair or replacement of the damaged pipe segment.

9.4.3 Response to Scheduled Indications

Responses to Scheduled indications are:

- Re-inspect the pipeline segment no later than 30 months after the assessment date, or
- Perform one of the actions relative to “Immediate Response” indications no later than 6 months from the assessment date.

9.4.4 Response to Monitored Indications

Monitored indications do not require a response until the next scheduled inspection.

9.5 Setting Reassessment Intervals

The reassessment interval shall be determined in accordance with ASME B31.8S and the SoCalGas Integrity Management Plan.

10.0 POST ASSESSMENT

10.1 Objectives

The Post Assessment process objective is to determine and document the overall effectiveness of the GWUT inspection method. This section is mandatory for casing applications and optional for non-casing applications.

10.2 Assessment of the GWUT Process

The PM shall review the GWUT assessment to determine if it was adequate for the assessment of the inspected pipe section and if there are improvements that can be made in the assessment process. The following sections provide instructions on how to analyze and document the assessment of the GWUT inspection method.

10.2.1 Technical Assessment Adequacy

The PM shall review the technical data to determine the adequacy of the assessment. The following questions shall be answered.

- Were the capacitance and coupling checks within specification?
- Did the sensitivity meet the specified requirements?
- Was the range sufficient to reach half the length of any cased segments?
- Could features be verified?
- Were feature characteristics the same as those found from the assessment?

10.2.2 Process Assessment Adequacy

The PM shall review the process of conducting the assessment and document areas for changes and improvement. The following specific areas shall be reviewed and identified improvements documented:

- Did the Pre-assessment Process achieve the objectives listed in Section 4.1?
- Did the review of the contractor procedures identify and address all pertinent inspection qualification issues?
- Was the inspection process including preparation and checks effective at determining a quality shot and sizing the indications?
- Was the post assessment process effective at determining the remedial actions necessary for assuring the integrity of the carrier pipe?

11.0 EXCEPTION PROCESS

11.1 Expectations

It is expected that all requirements of this procedure be met (with the exception of those indicated as optional) when conducting assessments of covered segments. However, exceptions may be taken by obtaining approval from the Integrity Management Program Manager IM and documenting the exceptions according to the actions prescribed in this section.

11.2 Objective

The objective of the Exception Process is to provide control and consistent documentation of exceptions to this procedure. Control and consistent documentation are necessary to maintain the integrity of the assessment projects through continuous process improvement, feedback, audits, and compliance with this procedure.

11.3 Exception Requirements

The PM shall document the exception including the reason and analysis for the exception as well as the alternative recommendation on Form E- Exception Report.

12. RECORDS AND RETENTION

12.1. Filing System

For each GWUT project the PM shall establish a suitable filing system to house all project documentation on the pipeline integrity group shared drive. The system shall be organized to allow the effective storage of pipeline data, inspection and analysis results, disposition of findings, and re-inspection intervals.

IP shall submit the completed report (i.e. text files exported from “Bellhole Inspection Software”), photographs and supporting documentation (e.g. corrosion grids) to the PM by e-mail or through the Company’s Electronic Data Transfer website (https://edt.sempra.com)

Physical changes made to the pipeline shall be documented and routed by the PM in accordance with Form 2112

12.2. Record Retention Policy

The record retention period shall be LOA+5 (life of the asset plus five years) in accordance with the SoCalGas Retention Schedule.

APPENDICES/ATTACHMENTS

- **APPENDIX A – GENERATION OF FAILURE/SENSITIVITY CURVES**
- **APPENDIX B – INDEX FOR PHMSA GWUT CHECKLIST & SOCALGAS PROCEDURE - CASINGS**
  - Flowchart
  - Forms

    Form A: Data Element Check Sheet

    Form B: Register of Known Features

    Form C: GWUT Inspection Procedure Review

    Form D: Tabulation of Features and Validation of Guided Wave UT Inspection

    Form E: Exception Report

- **APPENDIX A - GENERATION OF FAILURE / SENSITIVITY CURVES**

Background

This appendix describes the characteristics of the Failure / Sensitivity Curves utilized in Section 4.6 of the procedure.

Technical Approach

The approach utilized in this procedure provides an engineering methodology to determine the sensitivity requirements of a GWUT inspection that would have at least the same sensitivity as a pressure test.

Failure Curve

The failure curve for the pipe segment is determined utilizing KAPA formulations to generate a curve that represents a series of flaw dimensions that will result in failure of the pipe at the hydrotest pressure. This pressure can be calculated using the requirements in CFR 49, Part 192, Subpart J, §192.503. The equations necessary to generate the failure criterion are shown below.

Failure Criterion

$$\sigma = \bar{\sigma}\,\frac{1 - A/\tilde{A}}{1 - \left(\dfrac{A}{M\tilde{A}}\right)}$$

Where:

L is length of the corrosion defect in the axial direction.

D is the nominal diameter of the pipe.

t is the wall thickness of the pipe.

σ is the failure stress.

$\bar{\sigma}$ is the "flow stress," (1.1 SMYS for B31G; SMYS + 10,000 for Effective Area method)

A is the "effective area" of the displaced metal as discussed below.

$\tilde{A}$ is the area across the same flaw length prior to any wall loss.
M is the Folias factor.

For the original B31G Method it is calculated as:

$$M = \sqrt{1 + 0.8\frac{L^2}{Dt}}$$

For the Equivalent Area Method it is calculated as:

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

For $L > \sqrt{50Dt}$, $M = 0.032\frac{L^2}{Dt} + 3.3$

The figure below shows an Effective Area Method rupture curve for a 36-inch pipe, with an SMYS of 60 ksi and specified wall thickness of 0.5 inches. This curve represents the various blunt flaw sizes (depth and axial length) that would cause failure of the pipe at test pressure of 750 psi. Flaw sizes above the line would result in failure while flaw sizes below the line would not.

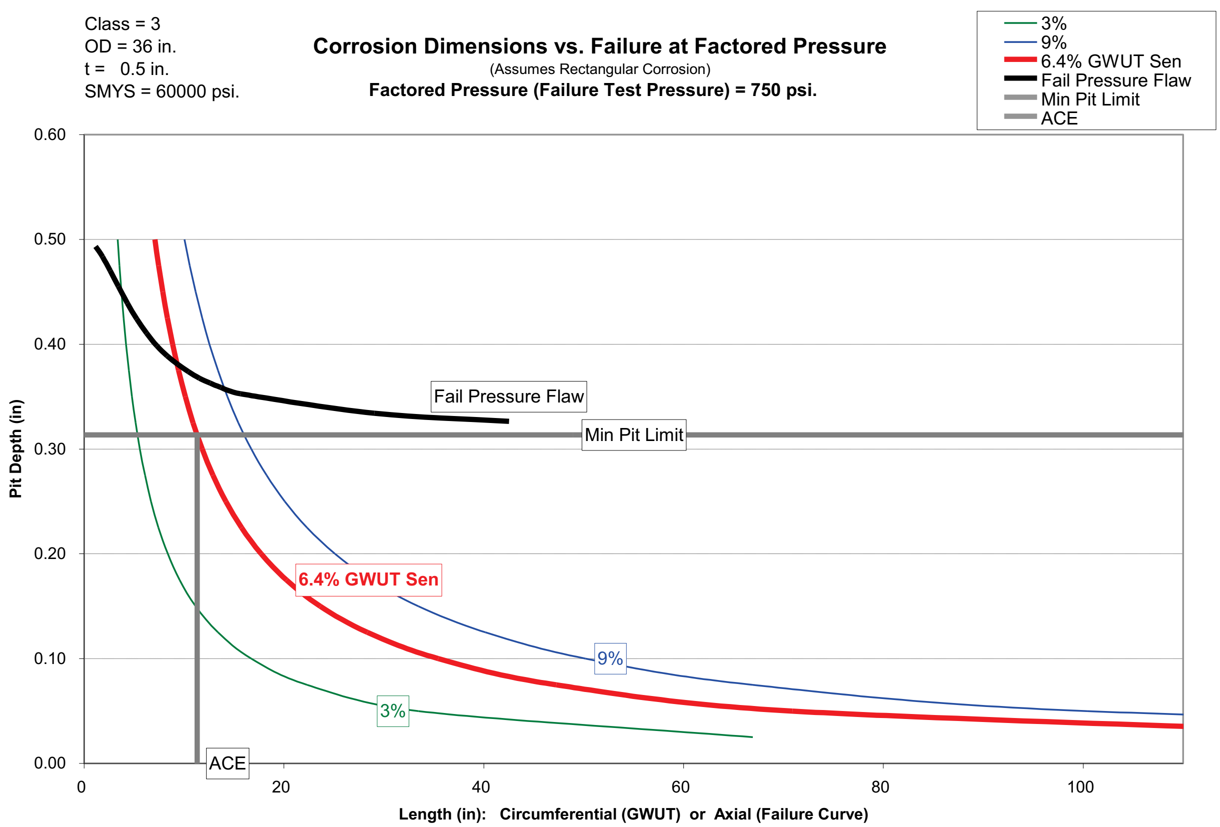


Figure A.1: Graphical depiction of minimum sensitivity calculation.

Minimum Wall Loss Detection Requirements

GWUT is not usually used to determine detailed measurements of the axial extent of a flaw. The conservative approach utilized in this procedure is to assume a “long flaw” and the corresponding wall loss needed to cause failure at test pressure of that flaw. By definition, further increase in axial length of a long flaw would not result in a change of the failure pressure.

In the figure the “Minimum Pit Limit” line represents the shallowest wall loss that would result in failure. Any wall loss below this line would not result in failure of the pipe at test pressure.

Circumferential Extent of Wall Loss

The sensitivity of GWUT is expressed as the minimum percent of the original cross sectional area change of the pipe wall. Cross sectional area change is a function of the wall loss and the circumferential extent of the wall loss. To determine the level of GWUT sensitivity needed to detect a minimum depth of wall loss the circumferential extent needs to be assumed.

In this procedure 10% circumferential extent is assumed. In this determination of sensitivity, assuming a larger percent of circumferential extent is less conservative. This assumption is a matter of engineering judgment. The RP may choose the circumferential extent that is most representative of the expected threats to the pipeline segment.

The vertical “10% Circumferential Line” is drawn at the 10% circumferential distance on the horizontal axis. The intersection between the minimum detection limit line and the 10% circumferential line describes the minimum level of sensitivity for the GWUT inspection.

GWUT Sensitivity

The GWUT sensitivity is measured in terms of cross sectional area loss (CSA). CSA is a function of the depth of wall loss and the circumferential extent of the wall loss. For a given sensitivity there is a family of flaws with varying depth and circumferential extent. In the figure the red “6.4% sensitivity curve” represents a series of flaw sizes that can be detected with at least 6.4% sensitivity.

Since the red 6.4% sensitivity curve includes the intersection of the minimum detection limit line and the 10% circumferential extent line the minimum required sensitivity for this example is 6.4%.

The blue 9% and green 3% sensitivity lines are provided to bracket other detection scenarios specific to the equipment and pipe. They are not required for determination of minimum GWUT sensitivity.

For use of GWUT as an "Other Technology," or stand-alone inspection technique, the actual minimum required sensitivity is the lower of: the sensitivity calculated in this procedure, or 5%.

Appendix B: Index for PHMSA GWUT Checklist & SoCalGas GWUT Procedure - Casings

(*Comments are comparison to the 11/1/07 PHMSA Guidelines*)

#	Title	Guideline Verbiage (key issues in bold)	Relevant Procedure Citations
1	**Generation of Equipment and Software**	The generation of both the equipment and the computer software is critical to the success of the inspection. Both major equipment vendors are on **version 3**. Prior versions may be used but require operator specific training and procedures for the earlier versions to achieve manually what later versions can do automatically. A Senior Level GWUT Equipment Operator is required for all equipment and software versions, non-automated, prior to version 3 or **First Level GWUT Equipment Operator with experience and training in use of the equipment/software version may be used with oversight by a Senior Level GWUT Equipment operator** of all procedures used and interpretation of data prior to completing evaluation of data. Automatic diagnostics, etc., may improve the efficiency of the test and reduce the time taken to collect data, but will not affect the sensitivity or ability to detect defects. This allows the operator to focus on the interpretation of the data rather than the mechanics of the inspection.	**4.2.4.1**– Equipment must be latest version (version 3). only GUL G3 is acceptable **4.2.4.2**- Equipment software must be latest version (version 3) **4.2.5.1**– GWUT Operator must be GUL Level I **4.2.6**– GUL Level II must review all shots
2	**Inspection Range**	The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the **maximum threshold sensitivity at 5%** cross sectional area (CSA). Any signal that has an amplitude that is about twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as, surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general the **maximum inspection range can approach 60 to 100 feet** depending on field conditions for a 5% CSA.	**4.1.5.1**– A sensitivity of less than or equal to 5% CSA must be achieved at the maximum inspection range. **4.1.5.2**– For planning purposes, GWUT assessment shot length is 80 feet.
3	**Achieving a complete inspection of the pipe**	To ensure that the entire pipeline segment is assessed there should be **at least a 2 to 1 signal to noise ratio** for the required wall loss anomalies to be detected, across the entire pipeline segment that is inspected. This may require multiple GWUT shots. **Double ended inspections** are expected. These two inspections are to be **overlaid** to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, **show the same near or midpoint feature (if present) from both sides** and show an approximate **5% distance overlap.**	**5.7.3.4, 5.7.3.5**– Inspection range defined by minimum 2:1 signal to noise ratio **5.7.3.6**– Shots taken from both ends of casing **5.7.3.6** – Shots from each end of casing overlaid to show the minimum 2:1 S/N ratio is met in the middle.

#	Title	Guideline Verbiage (key issues in bold)	Relevant Procedure Citations
4	**Sensitivity**	Sensitivity is defined as the ability to identify a reflection of a specified cross sectional change. The signal to noise ratio determines the detectability at a certain distance and thus sets the range. A sensitivity of 5% of the cross sectional area (CSA) must be achieved. By achieving a **5% sensitivity at the maximum inspection range**, a greater sensitivity may be achieved on the segment at locations closer to the inspection equipment. The minimum sensitivity achieved must be able to identify the smallest defects that will fail by rupturing in a hydrostatic test. **The locations and estimated CSA of all metal loss features in excess of the detection threshold shall be determined and reported.** The use of GWUT in the "Go-No Go" mode requires that **all indications** (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) **be directly examined** (or replaced) prior to completing the integrity assessment on the cased carrier pipe.	**4.1.5.1**– A sensitivity of less than or equal to 5% CSA must be achieved at the maximum inspection range. The sensitivity achieved must be able to identify the smallest defects that will fail by rupturing in a hydrostatic test. **5.7.6.1** – Locations and dimensions of metal loss features reported. **5.7.6.4-** Estimates of wall loss documented. **6.2-** All indications over 5% CSA directly examined prior to completing the integrity assessment.
5	**Frequency**	The frequencies used for the inspections must be in the range specified by the manufacturer of the equipment. A **sufficient number of frequencies** (at least 3) need to be run for each shot as to determine the best frequency for characterizing indications. The frequencies or **range of frequencies needs to be documented**. Different frequencies do not change axial position or clock position. If only a single frequency is selected certain defects may not be detected.	**4.2.4.1-** GUL G-3 equipment specified as acceptable. This automatically means multiple frequencies are collected through no intervention of the GUL operator. Frequency is dependent on pipe diameter and can typical vary from 7 to 48 kHz. **5.7.3.2** – Shot shall be reviewed at various frequencies (at least 3) and frequencies documented.
6	**Signal or Wave Type**	Most GWUT equipment can provide both torsional and longitudinal signals. Although the use of torsional waves may produce the best results, longitudinal waves may also be considered. Where only one wave type is available, it **must be torsional**. **Documentation of the wave type must be provided.** Torsional waves do not couple well with liquids, therefore if liquid is in or around the pipe segment then the operator must consider the use of torsional waves.	**5.5.1** – Torsional & longitudinal or torsional only. Wave type documented.

7	**DAC – required for each inspection**	**Setting the DAC** curve is an important step in establishing the effective range of a GWUT test and **must be performed** for each inspection. The DAC takes into account coating, pipe diameter, pipe wall and environmental conditions at the assessment location. DAC curves provide a means for evaluating the cross sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.	**5.7.3.3** – Set the weld DAC to known features for each inspection.

#	Title	Guideline Verbiage (key issues in bold)	Relevant Procedure Citations
8	**Dead Zone**	The Dead Zone is adjacent to the collar. GWUT uses pulse echo testing. The transmitted signal blinds the received signal, thus reducing the ability to obtain reproducible results. Therefore it can be determined from the length of the transmission pulse and the recovery time of the receiver circuits once the transmission burst has ceased. Inspection procedures need to account for the dead zone. The **length of the dead zone must be documented for each inspection**. Different inspections can yield different dead zones. If one is assessing cased crossings, the collar must be placed such that the **dead zone does not extend into the casing**, because a majority of indications in casings are typically located within the first few feet. A properly trained service provider can identify and report the dead zone. To properly assess the dead zone the service provider can move the collar and conduct an additional inspection of the dead zone**. An alternate method of obtaining valid readings in the dead is to use B-scan ultrasonic equipment and visual examination** of the external surface. It is recognized that not all manufacturers differentiate between the dead zone and the near field/zone.	**3.4** – Definition of Dead Zone **5.5.2** - Collar must be placed such that the dead zone does not extend into the casing. **5.4**– B-Scan testing is performed to detect wall loss in the Dead Zone. The length of the Dead Zone is documented.
9	**Near Field Effects**	The near field is the region beyond the dead zone where the receiving amplifiers are ramping up in power and thus is the region before the wave is established properly. This is not a function of the waveform but rather it is a function of the pulse echo collection method and is affected by pipe geometry. Classification is difficult in the near field due to reduced amplitude. Inspection procedures need to account for the near field. The **length of the near field must be documented for each inspection**. To properly assess the near field, the collar must be placed such that the **near field does not extend into the casing**, because a majority of indications in casings are typically located within the first few feet. A properly trained service provider can identify and report the near field. To properly assess the near field the service provider can move the collar and conduct an additional inspection of the near field. **An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface**.	**3.17** - Definition of Near Field **5.5.2** - Collar must be placed such that the near field does not extend into the casing. Alternately, dead zone/near field can be assessed by taking a second shot from another location. **5.4**– B-Scan testing is performed to detect wall loss in the Near Field. The length of the Near Field is documented
10	**Coating Type**	GWUT inspections that have been conducted on pipe coated with coal tar enamel, FBE, wax, extruded coatings, and some with girth welds coated with tape or shrink sleeves, which have not affected results. Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance. Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. **If an inspection is done and the required sensitivity is not achieved for the entire length of the cased pipe, then the use of GWUT is not feasible** and another type of assessment method must be utilized.	**4.1.4** – Data on pipe Coating and/or Casing annular contents required for GWUT Assessment. **4.1.5.1** – If the required sensitivity cannot be achieved for the entire length, then GWUT is not feasible and another type of assessment method must be used.

11	**End Seals**	The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range. The vast majority of indications on carrier pipes in casings occur in the first several feet and this area is critical to the integrity of the pipeline. Operators **will remove the end seal from the casing at each GWUT test location to facilitate limited visual inspection**. Water and debris can collect at the low point and cause electrolytic shorts. Venting can also be a source of moisture and debris, and are typically located near the casing ends. Operators will be **required to observe and collect the corrosion data**, if found, under the end seal and process the data to verify the GWUT was correct.	**5.2.2** –Remove end seal and visually inspect the area underneath it. Observe and collect the corrosion data, if found, under the end seal, in order to verify GWUT findings.
#	**Title**	**Guideline Verbiage (key issues in bold)**	**Relevant Procedure Citations**
12	**Weld Calibration – good method to set DAC curve.**	Accessible welds, along or outside the pipe segment to be inspected, are used in setting the DAC curve. A weld(s) in the access hole (secondary area) is an alternative to set the DAC curve. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. Having a **weld, in the near field or dead zone, between the transducer collar and the calibration weld is not permitted**. If the coating is removed from the weld prior to the inspection then the expected attenuation has been changed. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible or version 3 software is being used. **Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual cap height is different from the assumed cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve maybe required.** Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.	**5.7.3.3** – Weld DAC shall be based on known features; weld shall be outside the Dead Zone and Near Field and no weld permitted between collar and calibration weld; procedure provided for using measured weld crown in correcting the DAC and documentation; alternative means of calibration can be used if justified by sound engineering analysis and evaluation.

13	**Validation of Operator Training**	In the absence of an industry standard for certifying GWUT service providers, pipeline operators must require all guided wave service providers to have **equipment specific training and experience** for First Level and Senior Level GWUT Equipment Operators which include: 1. Equipment operation, 2. Field data collection, and 3. Data interpretation on cased and buried pipe. A **Senior Level GWUT Equipment Operator with pipeline specific experience must provide oversight and approve the final reports** of a First Level GWUT Equipment Operator. A Senior Level GWUT Equipment Operator must have additional training and experience beyond that required for the field data collection level operator, First Level GWUT Equipment Operator. This additional training must be specific to cased and buried pipe, and there **must be a quality control program** which conforms to Section 12 of ASME B31.8S. Guided Wave **Training and Experience Minimums** – for First Level and Senior Level GWUT Equipment Operators • Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe • Training, qualification and experience in testing procedures and frequency determination • Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent) • Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe – applicable for Senior Level GWUT Equipment Operator.	**4.2.5.1** – Personnel operating GWUT equipment and/or interpreting data must have GUL Level I or equivalent Certification from the equipment manufacturer. Specific training and experience requirements must be assured. **4.2.6** – Senior level (equivalent to GUL Level II) reviews each shot, approves reports and ensures that the GWUT operator is qualified.

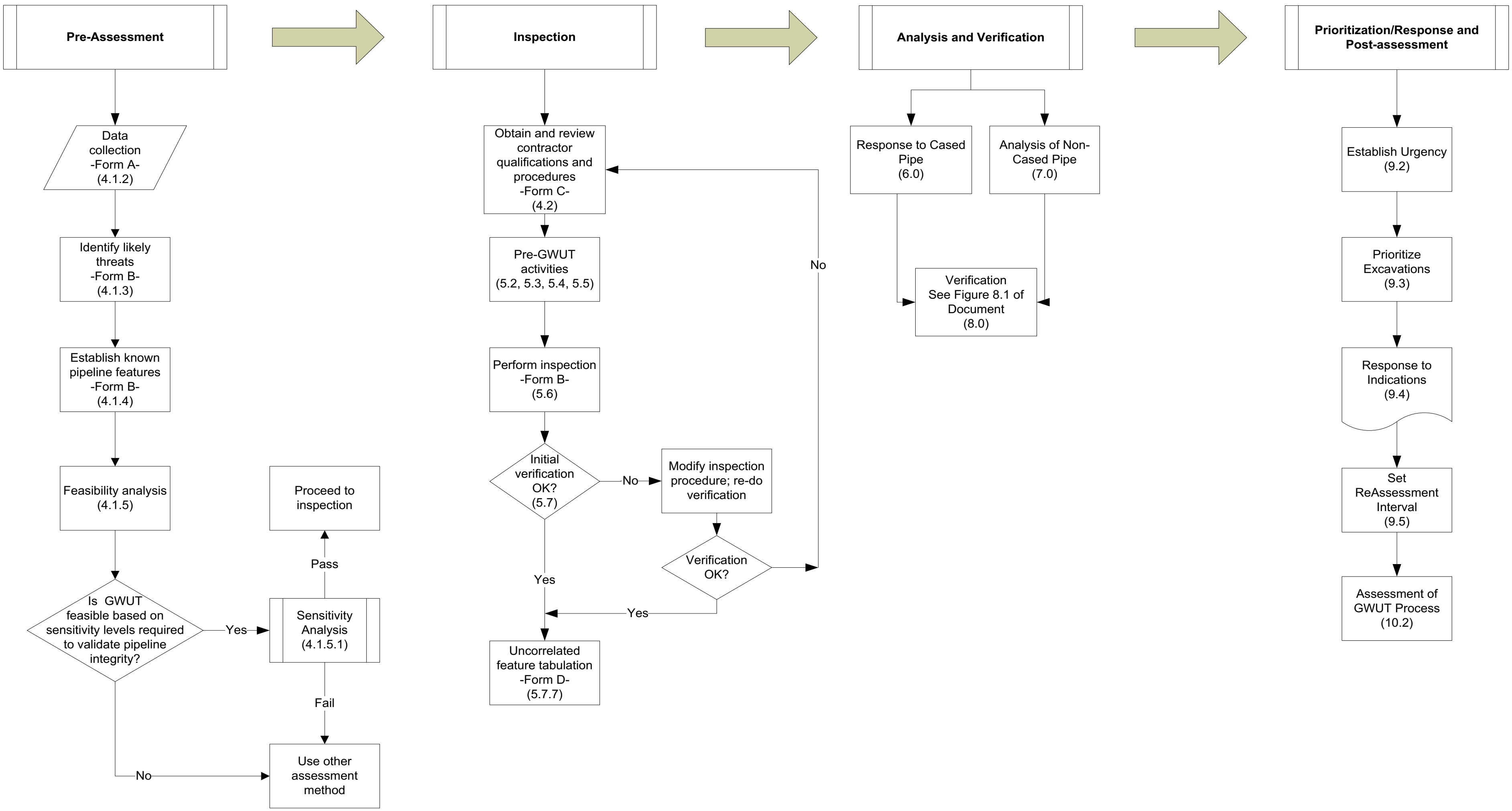
#	Title	Guideline Verbiage (key issues in bold)	Relevant Procedure Citations
14	**Equipment – should be traceable from vendor to contractor.**	The equipment and software must be readily traceable back to the manufacturer. **The version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., must be traceable and documented in the report. Only individuals who have been qualified by the manufacturer** or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, shall operate the equipment.	**4.2.4.1** - Latest generation GWUT device is being used and record the manufacturer, type and serial numbers of the relevant equipment. **4.2.5.1** – GWUT operator has GUL Level I or equivalent certification.
15	**Calibration, Onsite – diagnostic test on site and system check on site.**	The equipment must have been **calibrated per the equipment manufacturer's requirements** and specifications for both performance and time between calibrations prior to being shipped to the service provider. A **diagnostic check and system check shall be performed on-site** and each time the equipment is relocated. Where on site diagnostics show some discrepancies with the manufacturer's requirements and specifications, the testing shall cease until the equipment can be restored to manufacturer's specifications.	**4.2.4.3** – Equipment maintenance and calibration per manufacturer specifications. **5.7.2 -** On-site diagnostics is achieved by verifying and documenting amplitude balance, voltage per channel, and capacitance.
16	**Use on shorted (either direct or electrolytic) casings**	Shorted casings may not interfere with GWUT assessments. Guided waves are stress waves or mechanical vibrations in the pipe wall. They are not effectively coupled to and hence should not be affected by the electro-magnetic waves. There may be a reflection if the casing and pipe are in direct contact with high contact force, which may affect the GWUT results, but this can and should be addressed with procedures for any heavily loaded support. Shorted casings may not interfere with the GWUT signal to noise ratio and subsequent results. **If GWUT Service Operators see any evidence of interference other than some slight dampening of the GWUT signal** from **the shorted casing, it must be cleared to use GWUT**. All indications (wall loss anomalies) below the testing threshold (5% of CSA sensitivity) meeting the GWUT "Go-No Go, 18 Point Checklist" criteria, provided that there is no interference or masking of these indications (wall loss anomalies) if the indications are in the area of the short, do not need to be directly examined. All shorted casings found while conducting GWUT inspections must be addressed by the operator's SOPs and are not to be considered part of a GWUT procedure.	**5.7.3.7 –** If GWUT operator detects interference due to shorted casing, it must be cleared to use GWUT.

17	**Direct examination of all indications above the testing threshold is required**	The use of GWUT in the "Go-No Go" mode requires that **all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined** (or replaced) prior to completing the integrity assessment **on the cased carrier pipe**. If this cannot be accomplished then the use of GWUT is not considered feasible and alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.	**6.2** – All indications above 5% CSA are scheduled for direct examination.

<table>
<tr><th>#</th><th>Title</th><th>Guideline Verbiage (key issues in bold)</th><th>Relevant Procedure Citations</th></tr>
<tr><td>18</td><td>Timing of direct examinations of indications above the testing threshold</td><td>All indications (wall loss anomalies) that are identified above the threshold must be scheduled for direct examination. Under a prescriptive plan for these indications, the maximum time frame for each is 6 months for those pipelines operating at greater than 30% SMYS and 12 months for those operating at or below 30% SMYS. For those locations where the operating pressure is greater than 50% SMYS, the pressure must be reduced to 80% of the operating pressure at the time the indication is “discovered” by the GWUT. For those locations where the operating pressure is greater than 30% and less than or equal to 50% SMYS, then the operating pressure shall not exceed the operating pressure at the time of the “discovery” of the indication and the monthly leak survey shall be performed until the indication is directly examined. For those locations where the operating pressure is less than or equal to 30% of SMYS, the casings must be leak surveyed once a month until the indication is directly examined.
<table>
<tr><th></th><th colspan="3">Required Pipeline Response</th></tr>
<tr><th>GWUT Criterion</th><th>Less than 30%</th><th>Over 30 to 50% SMYS</th><th>Over 50% SMYS</th></tr>
<tr><td rowspan="4">Over 5% CSA and identified for examination</td><td>Interval < 12 month</td><td>Interval < 6 months</td><td>Interval < 6 month</td></tr>
<tr><td>Leak survey once /month</td><td>Direct Examination +</td><td>Direct Examination +</td></tr>
<tr><td>Direct Examination</td><td>MOP < psi @ discovery</td><td rowspan="2">Reduce to 80% MOP @ Discovery</td></tr>
<tr><td></td><td>Leak survey once /month</td></tr>
</table>
</td><td>6.2 – All indications above the testing threshold must be scheduled for direct examination, according to the rules and schedule laid out in this guideline.</td></tr>
</table>

FLOWCHART

Process Summary



Pre-Assessment
Inspection
Analysis and Verification
Prioritization/Response and Post-assessment
Data collection -Form A- (4.1.2)
Identify likely threats -Form B- (4.1.3)
Establish known pipeline features -Form B- (4.1.4)
Feasibility analysis (4.1.5)
Is GWUT feasible based on sensitivity levels required to validate pipeline integrity?
Yes
No
Sensitivity Analysis (4.1.5.1)
Pass
Fail
Proceed to inspection
Use other assessment method
Obtain and review contractor qualifications and procedures -Form C- (4.2)
Pre-GWUT activities (5.2, 5.3, 5.4, 5.5)
Perform inspection -Form B- (5.6)
Initial verification OK? (5.7)
No
Modify inspection procedure; re-do verification
Verification OK?
No
Yes
Yes
Uncorrelated feature tabulation -Form D- (5.7.7)
Response to Cased Pipe (6.0)
Analysis of Non-Cased Pipe (7.0)
Verification See Figure 8.1 of Document (8.0)
Establish Urgency (9.2)
Prioritize Excavations (9.3)
Response to Indications (9.4)
Set ReAssessment Interval (9.5)
Assessment of GWUT Process (10.2)

Form A: Data Element Check Sheet

Line Number:____ Date:______________________

Starting Mile Point:____ PJM:______________________

Ending Mile Point:_____________

Instructions: This Form shall be completed in accordance with Paragraph 4.1.2 of the procedure. The Project Manager or designate shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the comment field. This should include, as a minimum the reason required data is not available.

Requirements: R = Required, D = Desired or Recommended, N/R = Not Required

		Requirements			Data Sources						
ID #	Data Element Description	Need	Feasibility Assessment	Interpretation Analysis	District/Archive Files	GIS.	Field	Pipeline Databases	Maps Other	Sign Off	Comments
1.0 Pipe Related											

		Requirements			Data Sources						
ID #	Data Element Description	Need	Feasibility Assessment	Interpretation Analysis	District/Archive Files	GIS.	Field	Pipeline Databases	Maps Other	Sign Off	Comments
1.1	Material and grade	R	R	R							
1.2	Diameter	R	R	R							
1.3	Wall thickness	R	R	R							
1.4	Year manufactured	D	C	C							
1.5	Seam Type	D	C	C							

		Requirements			Data Sources						
ID #	**Data Element Description**	**Need**	**Feasibility Assessment**	**Interpretation Analysis**	**District/Archive Files**	**GIS.**	**Field**	**Pipeline Databases**	**Maps Other**	**Sign Off**	**Comments**
1.6	Bare Pipe	D	N/R	R							
2.0 Construction Related											
2.1	Year installed	D	R	R							
2.2	Recent route changes/ modifications not reflected in drawings	R	R	R							
2.3	Backfill Construction practices	R	N/R	C							

		Requirements			Data Sources						
ID #	Data Element Description	Need	Feasibility Assessment	Interpretation Analysis	District/Archive Files	GIS.	Field	Pipeline Databases	Maps Other	Sign Off	Comments
2.4	Location of major pipe appurtenances such as valves, and taps	R	C	R							
2.5	Length of casings	R	R	R							
2.6	Type of casing end seal	D	C	C							
2.7	Presence or absence of metallic short	D	N/R	C							
2.8	Type and spacing of insulators / centralizers	D									

		Requirements			Data Sources						
ID #	Data Element Description	Need	Feasibility Assessment	Interpretation Analysis	District/Archive Files	GIS.	Field	Pipeline Databases	Maps Other	Sign Off	Comments
2.9	Location of bends, including miter bends and wrinkle bends	R									
2.10	Underwater sections and river crossings	R									
2.11	Locations of river weights or anchors	D									
3.0 Soil and Environmental											

		Requirements			Data Sources						
ID #	Data Element Description	Need	Feasibility Assessment	Interpretation Analysis	District/Archive Files	GIS.	Field	Pipeline Databases	Maps Other	Sign Off	Comments
3.1	Soil characteristics & types including soil contamination	D	R	R							
3.2	Drainage	D	R	C							
3.3	Presence or absence of electrolytic short	D	C	C							
3.4	Frozen ground	R									
4.0 Corrosion Control											
4.1	Test point locations (pipe access points)	D	R	R							

		Requirements			Data Sources						
ID #	Data Element Description	Need	Feasibility Assessment	Interpretation Analysis	District/Archive Files	GIS.	Field	Pipeline Databases	Maps Other	Sign Off	Comments
4.2	CP maintenance history (rectifier adjustments, anode maintenance, etc.)over the past five years	D	R	R							
4.3	1st Assessment Requirement**:** All available CP Maintenance History	D	R	C							
4.4	Years without CP applied	N/R	R	C							
4.5	Coating type-pipe	D	R	C							

		Requirements			Data Sources						
ID #	**Data Element Description**	**Need**	**Feasibility Assessment**	**Interpretation Analysis**	**District/Archive Files**	**GIS.**	**Field**	**Pipeline Databases**	**Maps Other**	**Sign Off**	**Comments**
4.6	Coating type-joints	R	R	C							
4.7	Coating condition	D	N/R	R							
4.8	Routine pipe to soil potential survey data/history	D	C	C							
4.9	Data from other over the ground surveys (DCVG, CIS, or similar)	D	R	C							
5.0 Operational Data											
5.1	Operating stress level	R	R	C							

		Requirements			Data Sources						
ID #	Data Element Description	Need	Feasibility Assessment	Interpretation Analysis	District/Archive Files	GIS.	Field	Pipeline Databases	Maps Other	Sign Off	Comments
5.2	Monitoring programs (Coupon, patrol leak history etc.)	R	C	R							
5.3	Pipe inspection reports-excavation	D	C	R							
5.4	Repair history/records, steel/composite repair sleeves, repair locations	D									
5.5	Leak rupture history	D									

		Requirements			Data Sources						
ID #	**Data Element Description**	**Need**	**Feasibility Assessment**	**Interpretation Analysis**	**District/Archive Files**	**GIS.**	**Field**	**Pipeline Databases**	**Maps Other**	**Sign Off**	**Comments**
5.6	Evidence of external or internal MIC	D									
5.7	Type and frequency of third party damage	D									
5.8	Hydro test dates/pressures	R									
5.9	Other prior integrity related activities – CIS, ILI runs, etc.	R									

Form B: Register of Known Features Sheet 1 of 2

Instructions: This Form shall be completed in accordance with Paragraph 4.1 of the procedure.

1) Pipeline Number:_____________________________________

2) Segment Name:_______________________________________

3) Segment Description:

   a) diameter _____________ b) wall __________________ c) grade ___________________________

   d) age_________________ e) coating type_____________ f) casing length if applicable_________

4) Guided Wave UT Inspection Contractor: _________________

5) Guided Wave UT Equipment:____

6) Transducer Collar Location:____

7) Description of corrosion and other damage previously observed in or adjacent to this pipeline segment

   ☐ External corrosion ☐ Internal corrosion ☐ Mechanical damage

   ☐ Gouges ☐ Dents ☐ Dents containing gouges

   Describe range of maximum length, width, depths of corrosion or damage: ____

Form B: Register of Known Features Sheet 2 of 2

Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I
Location of Known Feature (stationing)	Expected Location of Known Feature Relative to Transducer Collar (Feature Sta. – Collar Sta.)	Description of Feature	Feature Dimensions	Clock Orientation (facing direction of increasing stationing)	Feature Detected by Guided Wave UT?	Detected Feature Consistent with Description?	Location of Detected Feature Relative to Expected Location	Comments

Project Manager: ________________________________ **Date**______________

Project Engineer: ________________________________ **Date**______________

Form C: GWUT Procedure Review Form

Date:______________________________ Company Organization or Vendor___________
Prepared By:________________________ Procedure Number________________________
Reviewed By:________________________

Requirement: Paragraph 4.2.3.7 in the Procedure provides the requirement and context for this form.

Procedure Content Review

Acceptable	Not Acceptable		Comments
☐	☐	Procedure Number	
☐	☐	General Description	
☐	☐	Location	
☐	☐	Set-Up	
☐	☐	Inspection Parameters	
☐	☐	Sensitivity	
☐	☐	Inspection Procedure	
☐	☐	Data Analysis	
☐	☐	Inspection Equipment	
☐	☐	Detection of Features	
☐	☐	Feature Characterization	
☐	☐	Inspector Qualifications	
☐	☐	Approval	
☐	☐	Equipment Serial #s	

General Comments:____

Approved **Not Approved**

☐ ☐ Comment: ____

Reviewer:______________________ Date:_______________

Project Engineer:______________ Date:______________

Form D – Tabulation of Features and Validation of Guided Wave UT Inspection

Instructions: This Form shall be completed in accordance with Paragraph 5.7.7 of the procedure.

Location (stationing) of transducer collar: ___________________________________

*Note all locations relative to transducer collar location

	Col. A	Col. B	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N
Feature No.	Estimated Feature Location	Estimated Feature Type	Estimated Feature Dimensions (L, W, d)	Dimensions + Tolerance (Lt, Wt, dt)	Dimensions for Integrity Calcs dt, L=20√Dt	Feature Classification	Actual Feature Location	Actual Feature Type	Actual Feature Dimensions	Comments / Explanation of Variance	Revised Feature Dimensions	Revised Dimensions for Integrity Calcs	Revised Classification	Feature Priority

Project Manager: ____________________________________ **Date**________________

Project Engineer: ____________________________________ **Date**________________

Form E: Exception Report

Date of Report:_________
Guided Wave UT Project number:___________________
Line Number:__________________

Instructions: Completing this form is described in Section 4.5

Paragraph Number of Exception:_________

Requirements of paragraph (Briefly state or Paraphrase): ________________________________
____
____
____
____

Alternative Plan: ____
____
____
____
____
____

Reason for Exception: ____
____
____
____
____
____

Recommendation: Should the procedure be changed? ☐ **Yes** ☐ **No**
Comments: ____
____
____
____

Project Manager:____________________________________ **Date**________________
Program Manager:___________________________________ **Date**________________
Project Engineer: ___________________________________ **Date**________________

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
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MAOP Evaluation of Corroded Pipe	SCG:	182.0050

PURPOSE: **To provide guidelines and procedures for evaluating the remaining strength of corroded pipe. The remaining strength values will result in the affirmation or reduction of the MAOP.**

1. POLICY AND SCOPE

1.1. This document has been identified as part of the Integrity Management Program and is subject to the Program's Quality Assurance Plan. This document shall be controlled per the guidelines established within the Program's Quality Assurance Plan. The Integrity Management Program applies to Transmission lines within high Consequence Areas as defined by the Code of Federal Regulations (Title 49 Part 192).

1.2. These guidelines are provided for calculating the maximum allowable operating pressure (MAOP) of a corroded pipe segment and apply only to pipe wall loss due to corrosion that does not involve the following:

1.2.1. Long seams or girth welds.

1.2.2. Mechanically caused defects, such as gouges, grooves and denting, or defects introduced during manufacturing.

1.3. The **Pipeline Integrity Engineering** shall be contacted if such uncorrected defects exist in a pipeline segment that is to remain in service, or if a corroded pipeline segment is likely to be subjected to significant secondary stresses, such as bending or high cycle pressure fluctuations.

1.4. The remaining strength evaluation can be applied to external corrosion, internal corrosion, or a combination of both types.

1.5. When the calculation in these guidelines is not applicable, other strength evaluation methods are available by consulting **Pipeline Integrity Engineering**. An example of another technique is pressure testing in accordance with Gas Standard **182.0170**, *Strength Testing – Pipelines and Facilities*.

1.6. Distribution pipe as defined in Gas Standard **223.0415**, *Pipeline and Related Definitions*, where uniform corrosion or closely grouped corrosion pitting resulting in large surface areas of pipe remaining wall thickness less than 30% nominal wall, should be repaired or replaced.

1.7. The remaining strength of a pipeline segment is determined by calculating the predicted failure pressure and thereby ensuring the operating safety factor meets the minimum safety factor required by the class location. This determines whether the corroded segment can safely remain in service or needs to be de-rated, repaired, or replaced.

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **Integrity Engineer or Technical Advisor**: The Integrity Engineer or Technical Advisor shall be responsible for the evaluations conducted throughout this process. This person shall be responsible for performing all remaining strength evaluations, including but not limited to those required by Gas Standard **167.0210**, *In-Line Inspection (ILI) Procedure* and Gas Standard **167.0209**, *External Corrosion Direct Assessment Procedure*, any other pipeline assessment method determined by the Company's Integrity Management Plan, and all routine pipeline maintenance.

2.2. **Inspection Technician:** This person is responsible for conducting all pipeline non-destructive evaluation (NDE) measurements with a standard non-destructive inspection method that is both accurate and repeatable. Measurements gathered during this inspection are qualified for ASME B31G, MB31G-0.85dL, and the Effective Area assessments.

2.3. **Field Technician:** This person is in the general labor pool of Distribution and Transmission pipeline personnel who performs any of the routine operations field tasks. Measurements gathered during these tasks are **only** qualified for the B31G assessment.

2.4. **Gas Engineering – Pipeline Integrity** shall be responsible for the development of the procedures established in this Gas Standard.

2.5. All **employees** shall be responsible for adhering to company safety procedures and follow all protocols identified in the Injury and Illness Prevention Program Binder under Manual **IIPP.4**.

2.6. The Integrity Engineer or technical advisor shall have pipeline industry and corrosion control experience. This person shall be formally trained on this procedure, Gas Standard **182.0050**. In addition, this person shall have documented training on the use of KAPA or RSTRENG.

2.7. The Inspection Technician shall have documented formal training and certification in NDE methods and pipeline inspection experience. This person can also be a Field Technician with acceptance of the Integrity Engineer or Technical Advisor. The Inspection Technician works closely with the Integrity Engineer or Technical Advisor to gather the necessary detailed data.

2.8. The Field Technician shall have pipeline field experience per the specific measurement task.

3. DEFINITIONS

3.1. **MAOP** – Maximum Allowable Operating Pressure

3.2. **Predicted Failure Pressure** – The pressure at which the corroded section will no longer hold pipeline pressure per the RSTRENG or KAPA methodology

3.3. **DOT- Transmission Piping** – See GS **223.0415**, *Pipeline and Related Definitions*

3.4. **DOT- Distribution Piping** – See GS **223.0415**, *Pipeline and Related Definitions*

3.5. **Operating Safety Factor** – The ratio of failure pressure to MAOP per specific pipe segment. Also known as predicted failure pressure ratio or rupture pressure ratio (RPR)

$$SF_{corr} = \frac{Pf}{MAOP}$$

SF_{corr} = *Safety factor of corroded area*

MAOP = Maximum allowable operating pressure (psig)

Pf = Predicted Burst Pressure (psig)

3.6. **Superficial Corrosion** – Corrosion that is less than 10% of the nominal pipe wall thickness and requires no reduction to the MAOP or repair of the line pipe. Further limits of acceptable corrosion are found in section 4.1

4. PROCEDURE

4.1. **Methods of calculation** – The Company recognizes the RSTRENG and KAPA programs as the acceptable methods for performing the three ASME code calculations used to evaluate the remaining strength of corroded pipe; B31G, Modified B31G-0.85dL, and Effective Area technique. These methods are based upon extensive pressure testing of actual corroded pipe segments. The method **used** will depend on the availability of detailed corrosion measurements and will be decided by **Pipeline Integrity Engineering.**

4.2. ASME B31G is the most conservative method but is the preferred method to evaluate remaining strength until detailed data is gathered. The other less conservative methods should not be used unless the corrosion profiles come from trusted sources or until more than one technician verifies the measurements. The variable "d" is the depth of the metal loss shown as a percentage of the wall thickness. Corrosion limits of this method are:

4.2.1. If $d \leq 10\%$, the corrosion is acceptable regardless of L.

4.2.2. If $11\% \leq d \leq 79\%$, the corrosion is assessed per ASME B31G.

4.2.3. If $d \geq 80\%$, the corrosion is immediately repaired per **167.0235**, *Immediate Repair Conditions – Transmission Pipelines*.

4.3. The Modified B31G-0.85dL (MB31G-0.85) calculation is less conservative and generally more accurate than B31G. The required input includes the longitudinal length of the corroded area and the maximum pit depth along this length. The variable "d" is the depth of the metal loss shown as a percentage of the wall thickness. The corrosion limits of this method are:

4.3.1. If d ≤ 20%, the corrosion is acceptable regardless of L.

4.3.2. If 21% ≤ d ≤ 79%, the corrosion is assessed per MB31G – 0.85dL.

4.3.3. If d ≥ 80%, the corrosion is immediately repaired per **167.0235**, *Immediate Repair Conditions – Transmission Pipelines.*

4.4. The Effective Area technique requires very detailed corrosion measurements and will potentially reduce repairs, replacements, and the lowering of MAOPs by lowering the level of conservatism built in the equation. This method requires corrosion measurements that accurately describe the contours of a corrosion patch. The variable "d" is the depth of the metal loss shown as a percentage of the wall thickness. Corrosion limits of this method are:

4.4.1. If d ≤ 20%, the corrosion is acceptable regardless of L.

4.4.2. If 21% ≤ d ≤ 79%, the corrosion is assessed per the Effective Area method.

4.4.3. If d ≥ 80%, the corrosion is immediately repaired per **167.0235**, *Immediate Repair Conditions – Transmission Pipelines.*

4.5. **Pressure Reduction** – Unless the metal loss or mechanical damage is known to be superficial, a pressure reduction shall be required during inspection and possible repair. Review Gas Standard **223.0180**, *Repair of Defects in Steel Pressure Piping* for these guidelines.

4.6. Measurements on the corroded area shall only be made after the pipe has been thoroughly cleaned to ensure accurate readings.

4.7. Inputs for the Calculations:

4.7.1. Nominal pipe diameter (D) in inches.

4.7.2. Pipe wall thickness (t) in inches – nominal wall is best used until actual wall can be verified.

4.7.3. Specified Minimum Yield Strength (SMYS) in psi.

4.7.4. Pressure (P) in psig – the established MAOP for the pipe segment.

4.7.5. Corrosion length (L) in inches – Either uniform or irregular spacing increments can be entered. Length is discussed in further detail in paragraph 4.8.

4.7.6. Corrosion depths (d) in inches – Either pit depth (PIT) or remaining wall thickness (RWT) measurements can be entered. Depth is depicted in Figure 1.

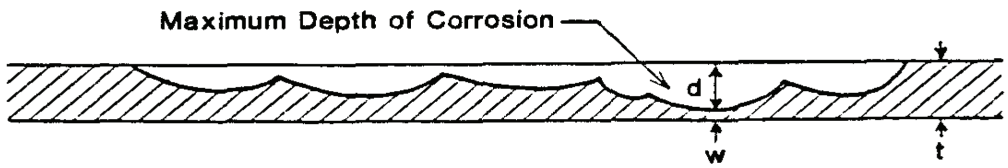

FIGURE 1
SECTIONAL VIEW OF CORRODED PIPE WALL WITH DIMENSIONS

4.8. Determining Corrosion Length

4.8.1. Regardless of the orientation or shape of the corrosion patch, the corrosion length is measured **parallel** to the longitudinal axis of the pipe, as depicted in Figure 2.

4.8.2. Adjacent corrosion patches will interact causing further reduction of the remaining strength than corrosion patches acting independent of each other. Corrosion interaction rules are used which affect the overall length of corrosion to be evaluated. They are defined by the orientation of the corrosion patch and are identified as Type I and Type II

4.8.3. Type I Interaction - Corrosion patches are considered interacting if the circumferential separation is **6t or less**. This is shown in Figure 3.

4.8.4. Type II interaction - Corrosion patches are considered interacting if the longitudinal (axial) separation is **1 inch or less**. This is shown in Figure 4.

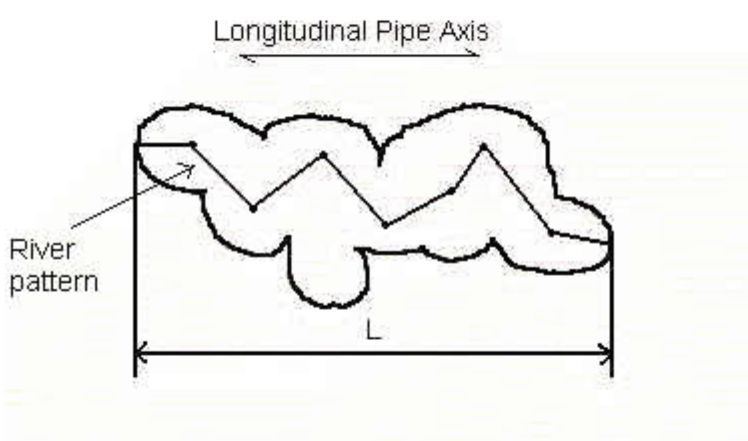

FIGURE 2
LENGTH OF CORROSION PATCH WITH A "RIVER BOTTOM" PATTERN

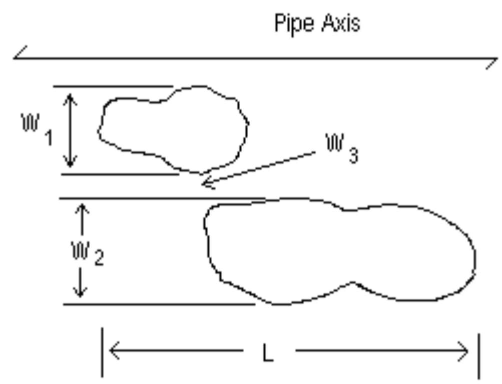

FIGURE 3
CIRCUMFERENTIAL CORROSION SEPARATION INTERACTION: THE SEPARATION DISTANCE BETWEEN ADJACENT CORROSION PATCHES MUST BE LESS THAN THE WIDTH OF THE SHORTEST CORROSION PATCH FOR THE VOLUMETRIC WALL LOSS AREAS TO INTERACT. IF $W_3 \leq 6T$, THEN $W_T = W_1 + W_2 + W_3$

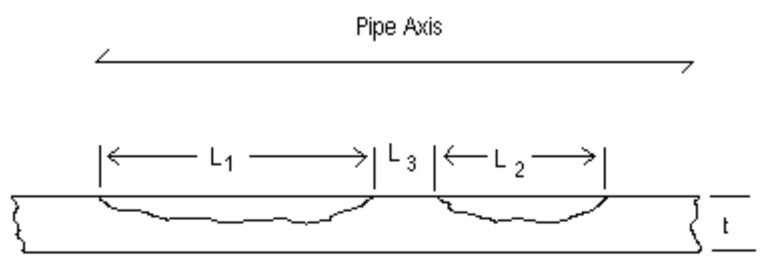

FIGURE 4
TYPE II - LONGITUDINAL CORROSION SEPARATION INTERACTION: THE SEPARATION DISTANCE BETWEEN ADJACENT CORROSION PATCHES MUST BE LESS THAN THE LENGTH OF THE SHORTEST CORROSION PATCH FOR THE VOLUMETRIC WALL LOSS AREAS TO INTERACT. IF $L_3 \leq 1$ INCH, THEN $L_T = L_1 + L_2 + L_3$

4.8.5. The effective area method is the most realistic method to use when dealing with interacting corrosion patches, but requires detailed information.

4.8.6. A failure will follow the path of least remaining wall thickness oriented axially along the pipe. This corrosion profile, depicted in Figure 2, is known as a “river bottom pattern.” A river bottom profile is automatically calculated when plotting the grid of a corrosion patch in KAPA.

4.8.7. The river bottom pattern is most accurately assessed with the Effective Area method.

4.8.8. The accuracy of the Effective Area method improves by taking measurements at closer intervals or smaller grids.

4.9. Outputs of the remaining strength calculation

4.9.1. Predicted failure pressure.

4.9.2. Operating safety factor, RPR.

4.9.3. Tables can be generated that show the allowable lengths of corrosion for specific maximum pit depths based on MB31G-0.85 and B31G.

4.10. Analysis of results

4.10.1. The safety factor of the evaluated area shall be reviewed to determine if it meets the minimum safety factor required by the class location and for determining the appropriate response for anomalies discovered through the **Pipeline Integrity Program**. Table 1 provides the corresponding safety factor and maximum allowable % SMYS for each area classification.

TABLE 1
DESIGN REQUIREMENTS BY CLASS LOCATION

Class Location	% SMYS	Design Factor	SF_{DR}, (1/DF), RPR
1	72	0.72	1.39
2	60	0.60	1.67
3	50	0.50	2.00
4	40	0.40	2.50

4.10.2. If the safety factor of the corroded pipe section is greater than the safety factor required by the class location, the remaining strength of the pipe is sufficient. If the corrosion is internal, the corrosion rate must be determined, and periodic inspections are made based on this rate. Contact **Pipeline Integrity Engineering** for further information.

4.10.3. When the corroded segment is left in service, the measures to arrest further corrosion in Gas Standard **186.0002**, *Design and Application of Cathodic Protection,* are followed.

4.10.4. If the safety factor of the corroded pipe section is less than the safety factor required by the class location (RPR is less than the SF listed in Table 1.), the corroded pipe section must adhere to the appropriate repair procedure:

4.10.5. For repairs to corroded steel piping, refer to Gas Standard **223.0180**, *Repair of Defects in Steel Pressure Piping* or GS **186.02**, *Cathodic Protection – Inspection of Exposed Pipe*.

5. OPERATOR QUALIFICATION COVERED TASKS
(See GS 167.0100, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 2.14.** - 49 CFR 192.485 - Recognizing general and localized corrosion, taking action: Transmission

- **Task 2.15.** - 49 CFR 192.487 - Recognizing general and localized corrosion, taking action: Distribution

6. RECORDS

6.1. Records shall be kept electronically in the Pipeline Integrity server and Region pipeline files as necessary. If the process requires a pipe segment to be repaired or replaced, records shall be kept per Form **677-1** *Pipeline Condition and Maintenance Report* (PCMR).

6.2. When MAOP lowering is required, records shall be kept per GS **182.0040**, *Changing Maximum Allowable Operating Pressure and Maximum Operating Pressure*.

6.3. Recommendations and calculations shall be maintained in the projects by line number files by the Integrity Engineer. They can take the form of memos, reports or email.

6.4. Distribution of the recommendations will be made to the Project Manager, District Operations Manager, Region Engineer and Pipeline Integrity management as applicable.

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PURPOSE **The purpose of this Standard is to provide guidelines for repairing defects in steel pressure piping.**

1. POLICY AND SCOPE

1.1. This Standard provides requirements and acceptable methods for repair of steel pipe including non-leaking and leaking defects and defects on new pipe not yet purged to gas. The standard covers repair on medium and high pressure pipelines.

2. RESPONSIBILITIES & QUALIFICATIONS

2.1. **Pipeline Integrity – Transmission Integrity and Analysis** is responsible for development of this Gas Standard.

2.2. All company employees, contractors and subcontractors performing a "**covered task**" on a Company facility as defined in **49 CFR 192.801(b)** shall be operator qualified in accordance with the requirements outlined in Gas **Standard 167.0100**, *Operator Qualification Program*.

2.3. **Distribution Regions** and **Transmission Districts** shall be responsible for using qualified welding procedures and qualified welders for welding on Company steel piping. Welding specifications are available on the Company website using the following link http://doclib.sempra.com/Reports/SCGWeldSpecs.aspx. Welding specifications not available on the website shall be requested from the Materials and Equipment Group located at the Pico Rivera facility.

2.4. All **employees** shall be responsible for adhering to company safety procedures and follow all protocols identified in the Injury and Illness Prevention Program Manual, **IIPP.1**.

2.5. The repair methods identified in Section 8: Method of Repair – New Piping, must comply with the provisions in 49 CFR 192.305, which states that each transmission line and main must be inspected to ensure that it is constructed in accordance with 49 CFR 192 regulations and that an operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection.

2.5.1. The inspection shall be documented, and the employee/contractor who performed the construction task requiring inspection and the person who performed the independent inspection must be identified.

3. DEFINITIONS

3.1. **Anomaly** – An unexamined pipe feature which is classified as a potential deviation from sound pipe material, welds, or coatings. All engineering materials contain anomalies which may or may not be detrimental to material performance. Indications of anomalies may be determined by nondestructive inspection methods such as in-line inspection (ILI).

3.2. **Discovery of a Condition** – Discovery occurs when there is adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline.

3.3. **General Corrosion** – Corrosion pitting so closely grouped as to affect the overall strength of the pipe.

3.4. **Hard Spots** – Localized changes in the hardness of steel that is typically caused by non-uniform quenching or cooling of the plate material during the manufacturing process. The uneven quenching results in a localized decrease in ductility and increases the formation of a more brittle martensitic microstructure.

3.5. **High Consequence Area (HCA)** – Refer to **Standard 192.02**, *Procedure for HCA Segment Identification.*

3.6. **Localized Corrosion Pitting** – Localized corrosion on a pipe where leakage is the likely failure mechanism.

3.7. **Predicted Failure Pressure (P_f)** – Also known as burst pressure. It is the internal pressure at which a pipeline segment will fail. This value is determined in accordance with **Standard 182.0050**, *MAOP Evaluation of Corroded Pipe*.

3.8. **Transmission Line** – A transmission line is defined as a pipeline segment that meets one of the following criteria:

3.8.1. Produces a hoop stress equivalent to 20% of SMYS or more based on the established maximum allowable operating pressure (MAOP).

3.8.2. Regardless of the operating stress level, transports gas within a storage field for the purpose of well injection or withdrawal, and is not a gathering line. Injection piping ends and withdrawal piping begins **at the respective block valve** *nearest the wellhead* **used to control** *or isolate* **flow to and from the individual well.**

3.8.3. Transports gas to a large volume customer that is not downstream of a distribution center. A distribution center is the point at which gas supply and gas delivery are demarcated by a block valve(s).

4. PROCEDURE

4.1. Defects found in steel pressure piping are repaired according to Tables 1, 2 and 3. In addition, repair by cylinder replacement is acceptable for all types of flaws. Alternative flaw assessment and repair methods may be acceptable based upon an engineering critical assessment (ECA) of the flaw type, flaw dimensions (length and depth), anticipated operating stresses, and mechanical properties of the pipe, longitudinal seam, component, or weld. Contact Pipeline Integrity – Transmission Integrity and Analysis for guidance.

4.2. If necessary, pipeline pressures are lowered to a safe level before inspection, repair welding or grinding is performed. See Section 6 for details.

4.3. All welding and preheating is done in accordance with **Standard 187.0056**, *Welding Field Guide* and **Standard 187.0055**, *General Welding Requirements.*

4.4. Temporary Repairs: When there is a hazard to the public, the repair of the defect is made without delay or the pipeline is shut down. Immediate temporary measures to protect the public will be implemented whenever:

4.4.1. A leak, imperfection, or damage that impairs the pipe's serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

4.4.2. It is not feasible to make a permanent repair at the time of discovery. As soon as feasible, permanent repairs will be made.

4.5. At least three inches of sound metal exists between the welds of adjacent patches, between fillet welds of adjacent bands, and between a fillet weld on a band and a girth weld.

4.6. Non-destructive testing techniques (e.g., ultrasonic or radiography) are used to help determine the type and extent of a defect if there is any doubt about its nature or limits.

4.7. Before welding on pressurized pipelines the visual and ultrasonic inspection requirements described in **Standard 187.0055**, *General Welding Requirements* are reviewed and the applicable inspections are performed. If internal corrosion is suspected, either a radiographic inspection or a B-scan ultrasonic inspection is performed in the area that will be affected by welding.

4.8. Welded patches, bands, and fittings, used to repair defects, should have design pressures at least equal to the design level of the piping.

4.9. The length (along the longitudinal axis of the pipe) of bands or patches is not limited.

4.10. Welds are inspected in accordance with **Standard 187.0175**, *Inspection and Testing of Welds on Company Steel Piping*. A repaired area of a girth weld that fails radiographic examination is not repaired by grinding and re-welding a second time.

5. PERMANENT FIELD REPAIR OF WELDS

5.1. Each weld that is unacceptable must be removed or repaired. A weld must be removed if it has a crack that is more than 8 percent of the weld length.

5.2. Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

5.3 A repaired area of a girth weld that fails radiographic inspection is not repaired by grinding and re-welding a second time. It is cut out and a cylindrical section installed if feasible, otherwise, a band or reinforcing sleeve is installed. See **Standard 187.0056**, *Welding Field Guide* and **Standard 187.0055**, *General Welding Requirements.*

5.4 Each weld that is unacceptable must be repaired as follows:

5.4.1 If it is feasible to take the segment of transmission line out of service, the weld must be repaired in accordance with the applicable requirements described in this section.

5.4.2 A weld may be repaired while the segment of transmission line is in service if:

5.4.2.1 The weld is not leaking; and

5.4.2.2 The pressure in the segment is reduced so that it does not produce a hoop stress that is more than 20 percent of the SMYS of the pipe; and

5.4.2.3 Grinding of the defective area can be limited so that at least 1/8-inch thickness in the pipe weld remains.

5.4.3 A defective weld which cannot be repaired in accordance with §5.4.1 or §5.4.2 must be repaired by installing a full encirclement welded split sleeve of appropriate design.

6. PRESSURE REDUCTION DURING INSPECTION AND REPAIR

6.1. For immediate repairs conditions, the operating pressure must be reduced to 80% of the pressure at the time of discovery of the condition.

6.2. For repairs not located in a HCA or not on transmission line, the operating pressure should be no more than 80% of the highest pressure that the pipeline has operated since the time the damage occurred or the highest pressure in the last 3 months.

6.3. No pressure reduction for inspection or grinding is needed if the predicted failure pressure of the flaw is at least 25% higher than the current operating pressure. The predicted failure pressure for corroded areas can be determined using **Standard 182.0050**, *MAOP Evaluation of Corroded Pipe.* The predicted failure pressure is determined using pipe properties, the dimensions of the flaw, and fracture mechanics calculations. Contact the staff of Pipeline Integrity – Transmission Integrity and Analysis for assistance in estimating the failure pressure of mechanical damage or corrosion.

6.4. Pressure reduction may be required during welding on thin wall pipelines or on areas of thin remaining wall. **Standard 187.0055**, *General Welding Requirements* includes guidance for welding on pressurized piping.

6.5. When welding is performed to repair existing welds the pressure should not produce an operating stress that is greater than 20% of SMYS of the pipe.

7. METHOD OF REPAIR - PRESSURIZED PIPELINES

7.1. Table 1 provides the minimum repair requirements for defects in non-leaking pressurized steel piping. Table 2 provides the minimum repair requirements for leaks in pressurized steel piping. Both tables also list applicable repair standards.

8. METHOD OF REPAIR - NEW PIPING

8.1. Allowable methods for repair of new pipe during construction and before the pipe is purged from air to gas are summarized by defect type in Table 3. Three methods are allowed:

8.1.1. Cylindrical section replacement;

8.1.2. Repair by grinding; and

8.1.3. Repair by grinding and re-weld.

8.2. Defects on new piping where repair by grinding is allowed:

8.2.1. Arc burns; and

8.2.2. Gouges, grooves or scratches.

8.3. Defects on new piping where repair by grinding and re-welding is allowed:

8.3.1. Defective girth welds.

8.4. Limitations on repair methods.

8.4.1. For arc burns, gouges, grooves and scratches:

8.4.1.1. Remaining wall thickness must be least 92% of nominal wall for 20" diameter pipe and larger.

8.4.1.2. Remaining wall thickness must be least 87.5% of nominal wall for smaller than 20" diameter pipe.

8.4.1.3. If remaining wall thickness is less than specified above, the only acceptable repair is cylindrical replacement.

8.4.2. For girth welds

8.4.2.1. Grind out those portions which do not meet the requirements of API Standard 1104, Section 6 (latest revision incorporated by reference in 49 CFR 192)

8.4.2.2. The repair can include grinding out the entire thickness of the weld.

8.4.2.3. Cracked welds, regardless of length, are never repaired; they are cut out.

8.5. Procedures for repair by grinding – arc burns, grooves and scratches.

8.5.1. Determine if grinding is permissible. Check the wall thickness of the pipe in the immediate vicinity of the repair with an ultrasonic gauge to confirm defect can be removed and have an allowable wall thickness remaining.

8.5.2. Grind defect using power grinder with flexible type grinding disk (soft pad), removing all visible evidence of defect.

8.5.3. When repairing arc burns, test for complete removal of the defect using a 20% solution of ammonium persulfate. Swab the ground-out area, any black area indicates that additional grinding is necessary.

8.5.4. Feather the ground area back into the pipe wall.

8.5.5. Confirm allowable remaining wall thickness with the ultrasonic thickness gauge.

8.6. Procedures repair by grinding and re-weld – girth weld.

8.6.1. Grind out the defect in the weld. Grinding of the defective area is limited so that at least 1/8-inch (3.2 millimeters) thickness in the pipe weld remains.

8.6.2. Preheat the pipe to 350° F before re-welding. Maintain the pipe metal temperature between 200°F and 400°F.

8.6.3. Use a 5/32" or 1/8" electrode for welding.

8.6.4. Re-weld the defective area.

8.6.5. After the repair is made, radiograph the weld. A repaired area of a girth weld that fails radiographic examination is not repaired by grinding and re-welding a second time. It is cut out and a new cylindrical section is installed.

9. OPERATOR QUALIFICATION COVERED TASKS
(See **Standard 167.0100**, *Operator Qualification Program*, Appendix A, *Covered Task List*)

- **Task 1.4 -0801** – 49 CFR 192.221 – Welding Operations.
- **Task 10.2 -** 49 CFR 192.713 – Making permanent field repair of imperfections and damages on transmission lines.
- **Task 10.3. -** 49 CFR 192.715 – Making permanent field repair of welds on transmission lines.

10. RECORDS

10.1. Repairs to pipelines designed to operate at less than 20% of SMYS are documented on the leak order, Form **677-1** *Pipeline Condition and Maintenance Report*, a completion drawing, or other appropriate record.

10.2. On in-service pipelines designed to operate at ≥20% of SMYS,-a record of each repair shall be maintained. The record shall include the date, location, repair description, and material information. Form **3222** *Design Data Sheets*, weld records, Form **677-1** *Pipeline Condition and Maintenance Report*, and ultrasonic observations are utilized when applicable.

10.3. On pipelines under construction, a record is made of the defects and whether the length of pipe was repaired or the defect removed.

10.4. Inspections required under §2.5 of this standard are documented on Form **2849** *Construction Inspection Report* or other appropriate record. The employee/contractor who performed the construction task requiring inspection, and the person who performed the independent inspection must be identified.

10.5 Repair and inspection records shall be retained in the work order or pipeline file, with a copy in the Pipeline Document Management System (PDMS) or Field Audit Collection Tool (FACT) for the life of the pipeline plus five years.

TABLE 1			
METHODS OF DEFECT REPAIRS FOR NON-LEAKING PRESSURIZED STEEL PIPING			
Hoop Stress	**Design Pressure**	**Defect Type**	**Minimum Repair Requirements**
Less than 20% SMYS	Less than 60 psig	Non-leaking cracks	Clamp (Standard 180.0035)
		Dents - depth more than 7% nominal pipe diameter	
		Defects other than cracks	Grind out defects up to 25% pipe wall thickness (Standard 223.0183)
	Over 60 psig but less than 125 psig	Non-leaking cracks	Weld Band or Sleeve[2] (Standard 223.0190)
		Dents - depth more than 7% nominal pipe diameter	Weld Band or Sleeve[2] (Standard 223.0190) Epoxy-grouted steel sleeve (Standard 223.0188)
		Defects other than cracks	Grind out defects up to 25% pipe wall thickness (Standard 223.0183)
20% SMYS or greater	125 psig or greater	Non-leaking cracks	Weld Band or Sleeve[2] (Standard 223.0190)
		Dents[1], hard spots associated with other defects	Weld Band or Sleeve[2] (Standard 223.0190) Epoxy-grouted steel sleeve (Standard 223.0188) Abandon Nipple (Standard 223.0181)
		Corrosion pits	Weld Patch[3] (Standard 223.0195) Abandon Nipple (Standard 223.0181) Weld band or Sleeve[2] (Standard 223.0190) Epoxy-grouted steel sleeve (Standard 223.0188)
		Arc burn, gouge, groove, scratch groove	Grinding (Standard 223.0183) Abandon Nipple (Standard 223.0181) Weld Band or Sleeve[2] (Standard 223.0190) Epoxy-grouted steel sleeve (Standard 223.0188)
		Defective girth weld	Grind and re-weld (Standard 223.0183) Weld Band or Sleeve[2] (Standard 223.0190)

1. Refer to repair method for limitations on dents.
2. Weld band or sleeve of appropriate design.
3. Weld patch permissible if SMYS of pipe is 40,000 psi or less. Patches are not used on lap weld, furnace butt weld, stitch weld or pipe of unknown longitudinal seam.

TABLE 2			
METHODS OF LEAK REPAIRS FOR PRESSURIZED STEEL PIPING			
Hoop Stress	**Design Pressure**	**Leak Type**	**Minimum Repair Requirements**
Less Than 20% SMYS	Less Than 60 psig	Seam of Longitudinal Leak	Weld Band or Sleeve[1] (Standard 223.0185)
		Corrosion Leak and Other	Leak Clamp (Standard 180.0035)
	Over 60 psig	Seam of Longitudinal Leak	Weld Band or Sleeve[1] (Standard 223.0185)
		Corrosion leak and Other	Leak clamp – max 400 psi (Standard 180.0035) Weld Band or Sleeve[1] (Standard 223.0185) Weld Patch[2] (Standard 223.0195)
20% SMYS or greater	Any	Seam or Longitudinal Leak	Weld Band or Sleeve[1] (Standard 223.0185)
		Corrosion Leak	Weld Band or Sleeve[1] (Standard 223.0185) Weld Patch[2] (Standard 223.0195)
		Pinhole Leak in Weld	Weld Band or Sleeve[1] (Standard 223.0185)
		All Others	Weld Band or Sleeve[1] (Standard 223.0185)

1. Weld band or sleeve of appropriate design.
2. Weld patch permissible if SMYS of pipe is 40,000 psi or less. Patches are not used on lap weld, furnace butt weld, stitch weld or pipe of unknown longitudinal seam.

TABLE 3			
METHODS OF REPAIR FOR NEW PIPING			
DEFECT TYPE		**METHOD OF REPAIR**	
1.	Arc burn, gouge, groove, or scratch	1. 2.	Grinding (Section 8.5) Cylindrical Section[1]
2.	Dents deeper than 1.4 inch or dent regardless of depth associated with a weld, defect, or stress concentrator	1.	Cylindrical Section[1]
3.	Defective girth welds	1. 2.	Grinding and re-weld (Section 8.6) Cylindrical Section[1]
4.	Cracks and hard spots associated with other defects	1.	Cylindrical Section[1]

1. The length of cylindrical section removed is at least 12 inches or one pipe diameter, whichever is greater.

NOTE: Do not alter or add any content from this page down; the following content is automatically generated.
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