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VIA FACSIMILE (713-272-2859) AND
CERTIFIED MAIL - RETURN RECEIPT REQUESTED

R.M. Seeley
Director, Southwest Region
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
8701 South Gessner, Suite 1110
Houston, TX 77074

Re: Notice of Amendment CPF No. 4-2007-5030M

Dear Mr. Seeley:

Representatives of the Office of Pipeline Safety conducted a comprehensive inspection of ExxonMobil Pipeline Company's (EMPCo) Integrity Management Program (IMP) during April 9-13, 2007; April 23-27, 2007; and May 7, 2007. Pursuant to this inspection, on August 7, 2007, EMPCo received a Notice of Amendment (NOA) and a Warning Letter from the Pipeline and Hazardous Materials Safety Administration (PHMSA). This letter is EMPCo's final response to the NOA. All items identified by the warning letter have been previously resolved.

The NOA identified one (1) area for amendment. This item is outlined in detail below, followed by EMPCo's completed actions to address the recommended improvement.

Item 1.
§195.452 Pipeline integrity management in high consequence areas
(j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?
(5) Assessment Methods. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
(iii) External corrosion direct assessment in accordance with §195.588

§195.588 What standards apply to direct assessment?
(a) If you use direct assessment on an onshore pipeline to evaluate the effects of external corrosion, you must follow the requirements of this section for performing external corrosion direct assessment. This section does not apply to methods associated with direct assessment, such as close interval surveys, voltage gradient

surveys, or examination of exposed pipelines, when used separately from the direct assessment process.

(b) The requirements for performing external corrosion direct assessment (ECDA) are as follows:

(1) General. You must follow the requirements of NACE Standard RP0502-2002 (incorporated by reference, see §195.3). Also, you must develop and implement an ECDA plan that includes procedures addressing pre-assessment, indirect examination, direct examination, and post-assessment

(3) Indirect examination. In addition to the requirements in Section 4 of NACE Standard RP0502-2002, the procedures for indirect examination of the ECDA regions must include -

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a pipeline segment

A. *EMPCo must modify their ECDA procedures regarding indication severity classification in the ECDA Plan Table A3.3 which does not appear to be as conservative as NACE RP-0502-2002 Table 3. NACE RP 0502-2002 table 3 gives example severity criteria for several indirect inspection methods.*

B. *EMPCo must modify their ECDA procedures to ensure that more restrictive criteria in addition to those required by NACE RP-0502-2002 are applied when conducting ECDA direct examination for the first time on a pipeline segment per §195.588. EMPCo has indicated that additional excavations will be conducted when conducting ECDA direct examinations for the first time on a pipeline segment; however, these additional excavations are a requirement of NACE RP-0502-2002 and, therefore, the IMP rule. As such, the additional excavations do not represent "more restrictive criteria" as described in §195.588.*

EMPCo Action:
EMPCo has completed modification of the ECDA process as noted above. The revised version of the Facility Integrity Management System (FIMMS) ECDA document is attached. Specifically, EMPCo has completed the following revisions:

- Modified the ECDA process to include indication severity classifications which are as conservative as NACE RP-0502-2002 Table 3. See Section A3.2.3 of the attached procedures.
- Modified the ECDA procedures to apply criteria more restrictive than that required by NACE RP-0502-2002 for first time ECDA's. See Section A3.3.2 of the attached procedures.

If you have any questions about the information presented in this letter, or desire additional information, please contact Johnita D. Jones at 512-306-7981 or Steve Koetting at 713-656-2070.

We look forward to hearing back from PHMSA regarding final closure of this NOA item.

Patrick T Doolan
Operations Manager
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I. SCOPE AND OBJECTIVE

Purpose:
The focus of the DA approach described in this document is to identify more probable locations of time dependant, time independent, and stable integrity threats.

This document describes the minimum requirements for ExxonMobil Pipeline Company's (EMPCo) DA Inspection Program. It provides guidelines for the proper selection of techniques used for DA inspections of pipelines. These techniques are utilized to detect potential integrity threats without the need to remove the pipeline from normal operating service.

The DA Inspection Program provides the minimum requirements for compliance with applicable Department of Transportation (DOT) and State Regulations and OIMS requirements, and to provide information to support risk assessments and risk management decisions.

This document describes the process of performing External Corrosion Direct Assessment (ECDA) to buried pipeline segments. This procedure had been developed in accordance with the NACE RP0502-2002: Pipeline External Corrosion Direct Assessment Methodology.

Scope:
Direct Assessment (DA) is a process through which an operator may be able to assess the integrity of a pipeline. This process integrates a knowledge of the physical characteristics and operating history of a pipeline with the results of diagnostic and direct measurements performed on the pipeline. The process is intended to improve pipeline integrity and safety by assessing and reducing the impact of external corrosion (EC) and third party damage (TPD). By identifying and addressing EC and TPD activity, ECDA seeks to proactively prevent external corrosion defects from growing to a size that affects the structural integrity of the pipeline segments, and proactively

identify TPD defects by identifying locations where TPD has occurred and associated coating has been damaged .

DA Process:

The DA methodology is a four-step process that requires the integration of data from multiple indirect field inspections and from direct pipe surface examinations with the pipe's physical characteristics and operating history. The four steps of the process are:

1. Pre-Assessment
2. Indirect Inspection
3. Direct Examination
4. Post-Assessment

Each step of the DA Process is covered in detail below.

Pre-Assessment:

The Pre-Assessment step collects historic and current data to determine whether DA is feasible, what indirect inspection tools are appropriate, and defines DA regions. The types of data to be collected are available on alignment sheets, on maintenance records, in annual corrosion surveys, on encroachment and foreign line crossing reports, on hydrostatic pressure test records, entered in a Geographic Information System (GIS), in job or projects records in local and centralized record storage, and in the memories of personnel who have worked on and maintained pipeline facilities over the years. Past history of any TPD events on the applicable pipeline segment(s) and similar segments must be divulged to the DA Service Provider during the Pre-Assessment phase of a DA project such that adequate analysis and inspection for TPD can be planned for Indirect Inspections and Direct Examinations. **See Attachment 3: Execution, Pre-Assessment**

Indirect Inspection:

Indirect inspection covers above ground inspections to identify and define the severity of coating faults, other anomalies, and areas where corrosion activity may have or may be occurring. Normally, two or more indirect inspection tools are used over the entire pipeline segment to provide improved detection reliability under the wide variety of conditions that may be encountered along a pipeline right-of-way. **See Attachment 3: Execution, Indirect Inspection**

Direct Examination:

The Direct Examination step includes analyses of indirect inspection data to select sites for excavations and pipe surface evaluations. The data from the direct examinations are combined with prior data (i.e. from pre-assessment and indirect steps) to identify and assess the impact of external corrosion or TPD on the pipeline. **See Attachment 3: Execution, Direct Examination**

Post-Assessment:

The Post-Assessment step covers analyses of data collected from the previous three steps to assess the effectiveness of the DA process and determine reassessment intervals. **See Attachment 3: Execution, Post-Assessment**

Integration of Results into IMP Processes

When the DA inspections are completed and a final report is received from the DA service provider, results from the DA Integrity Assessment are integrated with all other integrity data, exactly the same as other integrity assessments such as hydrostatic pressure test and In-Line Inspection within EMPCo's Integrity Management Program. The results of Data Integration is used to drive additional Preventive and Mitigative (P&M) processes for each pipeline segment. Special attention to Third Party Damage threats must be considered when analyzing data from DA projects and additional P&M activities must be considered to mitigate any TPD threats on lines assessed with Direct Assessment. If TPD is identified as a significant threat to the pipeline segment, additional preventive measures must be implemented by the operator and measures are to be taken to monitor the effectiveness of those additional preventive measures.

II. RESOURCES AND RESPONSIBILITY	**Risk and Integrity Manager**: Responsibility to assure that the Direct Assessments are implemented effectively. Is responsible for seeking regulatory approval to use DA for selected pipeline segments. Approves process and program exceptions. **Risk and Integrity Adviser:** Responsible for maintaining assessment schedule including integrity assessment method. Collects data on effectiveness of program. **Field Steward(s)**: Designated Local Operations Personnel and Field Engineers who are responsible for executing DA Project Field Inspections and locating records and personnel with knowledge to be gathered during pre-assessments. **Qualified Individuals:** Risk and Integrity Specialists and selected Field Engineers who are responsible for reviewing the results of integrity assessments and preparing repair and preventive and maintenance plans from data collected during the DA process. **Engineering Specialists**: Pipeline Integrity Specialist, Risk Assessment Specialist and others who set acceptability of DA process procedures and specifications. The Pipeline Integrity Specialist serves as Program Steward and the Program Expert for the DA Process and must be consulted for all changes to this process and for all program exceptions. **Pipeline Safety Advisor:** Responsible for providing formal notifications to the applicable State Regulatory Agencies for approval to use the Direct Assessment process for Integrity Assessment of pipeline segments in accordance with Integrity Management Program (IMP) and High Consequence Areas (HCA's) regulations. **Databases:** HCA Database, Geographic Information System (GeoIS) Databases, Central Information Center (CIC), CPDM Corrosion Database

III. PROCESSES AND PROCEDURES

A. PLANNING

DA is addressed in DOT Regulation Title 49 CFR Part 195.452, *Pipeline Integrity Management in High Consequence Areas* and in DOT Regulation Title 49 Part 192 Subpart O, *Pipeline Integrity Management.* These sections allow Direct Assessment under the section of the liquid pipeline regulation 195.452 (c) (1) (i) (C) External Corrosion Direct Assessment in accordance with 195.588 (requires more stringent criteria than NACE RP 1502-2002: External Corrosion Direct Assessment), with appropriate notification and approvals by State regulators (as applicable), and in section 192.923 in the gas pipeline regulation. A DA program that exceeds the requirements of NACE Standard Recommended 0502-2002, *Pipeline External Corrosion Direct Assessment* can be used in lieu of the DOT hydrotest or In-Line Inspection requirements, and is an excellent option if a pipeline cannot tolerate any sizable amount of downtime, as would be the case of a hydrotest, and is not smart pig compatible (and cannot be feasibly modified to become smart pig compatible) such as a dual diameter line or very short pipeline segment. DA is not appropriate for all pipeline segments. The process is self-validating and so continually verifies that the DA process is applicable and is an appropriate integrity assessment to the particular pipeline segment. At this time EMPCo has only adopted DA to apply to a limited number of pipeline segments. The pipeline segments are limited to those with viable integrity threats of External Corrosion and TPD. Pipeline segments discovered to have susceptibility to significant internal corrosion, long seam failure, or stress corrosion cracking must be eliminated from consideration as ECDA candidates until such time as other processes are available to evaluate those threats. Similarly, pipeline segments that have areas of limited accessibility where the indirect techniques cannot suitably inspect nor the direct examination techniques provide sufficient data may not be appropriate candidates for DA. Finally, since DA is heavily data driven, segments with limited available historical data should be excepted from the DA process. It should be noted that a short pipeline segment can be 100% directly examined using the DA process as a valid integrity assessment without using Indirect Inspection techniques.

B. Execution

See Attachment 1: Available Indirect Inspection Techniques

See Attachment 2: Available Direct Examination Techniques

See Attachment 3: Execution

C. Data Management & Integration

The DA process is heavily data dependent. The pre-assessment process results are normally available within three to six weeks, depending on the availability of information. The indirect surveys are dependent on line access. The direct surveys are dependent on the ability to complete excavations on a pipeline. The detailed final analysis of the data usually takes from one to two months to get results following the completion of the direct surveys. DA results are maintained in corporate databases to be further integrated into a risk analysis and/or GIS platforms. Hard copies of the DA results are to be maintained at the respective field office and in the CIC.

D. Corrective Actions

After the initial program results are obtained and reviewed following the completion of the DA study, any major anomalies can be investigated with further investigative excavation and corrected according to the highest risk prioritization. See EMPCo Integrity Management Program Manual

IV. MEASUREMENT AND VERIFICATIONS	**Measurement:** • # of Segments and HCA Mileage assessed with DA • # of leaks after DA, in and outside of HCA's • # of repairs made during and as a result of DA **Verification:** • # of anomalies ID'd where ILI or Hydro methods are incapable of identifying • # of other integrity issues addresses as a result of DA • # of assessment method changes made due to identification of segment incompatibility with DA process.
V. FEEDBACK AND CONTINUOUS IMPROVEMENT	Periodically, the Program Steward will meet with Engineering's Pipeline Integrity Specialist and designated others as needed, to conduct a formal self-assessment of the DA Program. This internal self-assessment will review processes and results, technical aspects and analyze any audits or other assessments performed since the last self assessment. Results of the formal internal assessment will also be reviewed with the Integrity Management Team along with the proposed plans for any ongoing program improvements and refinement.
VI. REFERENCE MATERIALS	The following documents were used in writing this document: • Department of Transportation Regulations Title 49 Part 195 • Code of Federal Regulations 49CFR195.452, *Pipeline Safety: Pipeline Integrity Management in High Consequence Areas.* • Code of Federal Regulations 49CFR192 - *Subpart O: Pipeline Integrity Management* • NACE Standard RP0502-2002, *Pipeline External Corrosion Direct Assessment Methodology* • ASME B31.8S: *Managing System Integrity of Gas Pipelines*

	• API 1160: *Managing System Integrity for Hazardous Liquid Pipelines* • EMPCo OIMS Manual • EMPCo In-Line Inspection FIMMS Document • Vendor Data

Attachment 1: AVAILABLE INDIRECT INSPECTION TECHNIQUES Technical Background

Direct Assessment utilizes a number of survey techniques to determine the integrity state of a pipeline. Listed below is a description of some of the more common methods presently used to conduct indirect surveys.

A1.0: Close Interval Survey (CIS)

Close interval surveys, which are also referred to as pipe to soil and potential gradient surveys, are applicable to all buried pipelines with an earthen cover. Close interval surveys are used to measure the potential difference between the pipe and the earth. Close interval surveys are typically used to determine cathodic protection (CP) levels, shorts to other structures, and stray current areas. There are various types of close interval surveys, including on/off potential surveys, depolarized potential surveys and on potential surveys. These survey techniques are limited in their ability to detect small coating holidays and are difficult to use in areas that are paved over. See also EMPCo FIMMS Close Interval Survey procedures.

A1.1: Method, Equipment and Reporting:

- Structure-to-electrolyte measurements shall be taken at intervals specified by the operator using a calibrated copper-copper-sulfate reference half-cell and high resistance direct current (DC) voltmeter.
- The condition of the reference cell must be monitored to ensure the accuracy of the voltage measurements. The plastic tube shall be kept full of saturated solution with some extra copper crystals to ensure the solution remains saturated. The plug must be inspected periodically to ensure it is moist and clean. If the cell leaks, cracks, or other damage is observed, the cell shall be replaced.
- The reference half-cell shall be positioned on the surface directly above the pipeline to be investigated. If this is not possible, place the reference cell off to the side of the structure where the nearest soil/earth exists. If this distance exceeds five (5) feet, a ½ inch boring (bar hole) with repairs shall be made at a depth necessary to obtain satisfactory contact with soil/earth to provide accurate and meaningful voltage measurements directly over the facility.
- If the soil is dry, moisten each test point, but do not saturate with water.
- If it is necessary to take voltage readings on a concrete surface, place a clean wet cloth on the concrete and then place the reference cell on the cloth.
- Voltage readings on macadam, asphalt (black top) surface shall never be taken unless a ½ inch boring is made to contact soil beneath the macadam surface.
- If one or more segments of pipe are protected by an impressed current rectifier system, the contractor shall have the capability to simultaneously interrupt all rectifier systems to ensure proper on/off voltage measurements are retrieved.
- ExxonMobil shall provide the contractor with location and acceptable limits of operation for all impressed current rectifier systems prior to test. The contractor shall read voltage and current outputs before beginning test to ensure proper operational output. Should any of the system outputs vary more than +/-25%, the contractor shall contact ExxonMobil's representative to investigate and correct before proceeding with the test.
- The contractor is required to retrieve static voltage measurements for those locations where the instant off potentials are less negative than –0.85 VDC to demonstrate and achieve acceptable criteria.
- The criteria for cathodic protection shall be in accordance with the Department of Transportation, Office of Pipeline Safety, Title 49, Part 195,

- The contractor shall record and plot on the appropriate data format the location of all cathodic test stations associated with but not limited to insulating joints, anodes, sleeves, rectifiers, valves and other meaningful pipeline or field components/conditions as well as those locations with significant stray current interference or depressed voltages (+/-25%) to facilitate positioning and analysis.

The contractor shall secure voltage recorders in areas determined to have stray current interference from the electrified railroad to ensure an uninterrupted 24-hour period to obtain an adequate sampling of voltage measurements for analysis.

A1.2: Direct Current Voltage Gradient Technique (DCVG)

DCVG (or alternatively ACVG) surveys are typically used to detect small to large holidays. They are sometimes used to determine whether a region is anodic or cathodic, but this technique cannot determine CP levels.

A1.2.1: Method, Equipment, and Reporting

Pre-job Considerations:

The following activities should be performed to allow the proper development of the DCVG coating evaluation:

A. Pipeline Data Collection:

- Pipeline material (steel, cast iron, etc.) and grade
- Diameter
- Length
- Wall thickness
- Year manufactured
- Type of coating

B. Pipeline Construction Data:

- Year Installed
- Route maps / Arial photos
- Construction Practices
- Road crossings along the pipeline route
- Location of valves, isolation devices (aboveground or underground), CP test points, electrical junction boxes
- Location of casings
- Pipeline depth of cover
- Soil chemical and physical properties
- Parallel pipelines in corridor and Pipeline crossings

C. Cathodic Protection System Data:

- Type of CP system (Impressed current or galvanic)
- Number and specifications of transformer rectifiers in the system
- Type of anode beds
- Cathodic Protection System Historical Data (On, Instant Off inspections, TR inspections, Close Interval Surveys, other CP system inspections)

D. Verification of the physical condition of the pipeline right of way

Instrumentation and Equipment:

Electrical measurements require proper selection and use of instruments. Recording potential differences require instruments that have appropriate voltage ranges. The user should know the capabilities and limitations of the equipment, follow the manufacturer's instruction manual, and be skilled in the use of electrical instruments. All survey equipment should be in good physical condition and properly calibrated before and during the Direct Current Voltage Gradient (DCVG) coating condition evaluation.

DCVG Equipment:

Interrupter: A DCVG (asynchronous) signal must be introduced to the pipeline system. This can be achieved by connecting a DC power supply unit to an Interrupter with a 1/3 of a second close and 2/3 of second open cycle and to the pipeline and a proper grounding. The equipment should be capable of raising a signal strong enough to create significant gradients around pipeline coating flaws. If available, the CP system can be used as a DC power supply.

DCVG Meter and probes:

Gradients in the soil must be measured with a digital or analog voltmeter with different voltage scales. The voltmeter must be connected to a pair of electrolytic probes.

Factors that may influence instrument selection for field testing:

- Input impedance (digital instruments)
- Input resistance or internal resistance (analog instruments)
- Sensitivity
- Conversion speed of analog-to-digital converters used in digital or data logging instruments
- Accuracy
- Instrument resolution
- Ruggedness
- Alternating current (AC) and radio frequency (RF) rejection; and
- Temperature and/or climate limitations

To log the coating flaw location, the distance to an above ground reference point must be measured. A pedometer may be used for that purpose. The precise distance must be measured along the pipeline route. If the DCVG equipment has no data logging capabilities, the distance information must be logged in a written format. The DCVG Operator may use a Geographical Positioning System unit to log coating flaw location.

Introduction of DCVG Signal in the pipeline:

Pipeline with no cathodic protection system installed: When an underground pipeline does not have a cathodic protection system, a DC interrupted current must be applied. A temporary DC supply unit must be connected to a proper grounding and to the pipeline through an interrupter with DCVG cycle interruption. The DCVG signal must be raised to an adequate level in the pipeline in order to locate small coating flaws at both ends of the section to be inspected. Verification must be done to guarantee the isolation of the DCVG signal from foreign pipelines and structures.

If the underground pipeline is protected with an impressed current CP system, the TR may be used as the DC power supply. An interrupter with DCVG cycle must be installed in between the TR and the pipeline. The DCVG signal must be raised to an adequate level in the pipeline in order to locate small coating flaws at both ends of the section to be inspected. Verification must be done to guarantee the isolation of the DCVG signal from foreign pipelines and structures.

Pipe Location and Marking Procedure:

To start a DCVG coating evaluation, the underground pipeline route must be determined. An electromagnetic pipe locator may be used to trace the pipeline route accurately. The pipeline route should be flagged at least every 100 feet to avoid misleading DCVG evaluation, especially if the coating is in very good conditions. If the coating condition is poor coating defects marking may act as pipeline route flags

Survey Procedure:

Verify adequate DCVG signal level at both ends of section to inspect

Data Validity: to be supplied
Data Format: to be supplied

1.3: AC Current Attenuation (ACCA)

This survey technique is typically used to qualitatively rank coating condition and highlight pipeline sections with the largest holidays. The C-Scan survey is used to detect various coating holidays on buried pipe, under paved areas and in frozen ground.

This technique was developed specifically to assess the electrical integrity of pipeline coatings on land based pipelines where the primary defense against external corrosion is the applied coating. A current is applied to the pipeline and coating damage is located and prioritized according to the magnitude of current attenuation.

The system is based on accurate measurement of the electromagnetic field radiated by a buried pipeline to which an AC signal current has been applied. The strength of the signal current remaining on the pipeline will decrease with increasing distance from the signal generator as the current gradually escapes to earth through the coating and any faults that may be present. The rate of loss (signal attenuation) will be dependent on the electrical integrity of the coating. In other words, the lower the coating conductance value, or the higher its resistance value, the lower the rate of signal loss. Any coating anomaly that results in a significant loss of current, hence changing the rate of attenuation for that section locally, can be observed readily by this survey technique.

The 'signal attenuation rate', usually measured in millibels per meter (mB/m) or millibels per foot (mB/ft), is the logarithmic rate of loss of signal current over the section of pipeline between any two survey points. The 'millibel' is a dimensionless ratio and thus independent of the value of the initial signal placed on the pipeline, and of the ground conditions (as they relate to total circuit impedance). It is determined by the average condition of the coating and by the area of coating in contact with the ground, per meter or foot of pipeline.

Therefore, for a pipeline of constant diameter the 'attenuation rate' is an absolute measure of average coating quality over each section surveyed. Using the electromagnetic field rather than ground contact means that the system is unaffected by variations in pipeline depth, changes in local electrical ground resistance or the presence of insulating ground surfaces such as ice, concrete, tarmac and sand.

Electromagnetic current attenuation survey systems can be used alone for overall coating evaluation (DA macro assessment) covering up to 30-50 miles (50-80 kilometers) per day and, alone or in combination with other techniques such as pin-to pin, DCVG or pipe to soil potential measurements, for location and/or evaluation of individual coating faults within an already identified 50-500 feet (15-150 meters). These will include sections showing 'high attenuation' on the macro assessment survey together with selected 'high consequence' (HCA) sections of pipeline (DA micro assessment). Coating condition can also be checked on newly installed or repaired pipelines, before back-fill is consolidated

In the most advanced electromagnetic current attenuation systems, all survey data can be stored internally and may be analyzed and displayed, or printed out in tabular or graphic form when required.

A1.3.1: Instrumentation and Equipment

The main elements of the system are the Signal Generator and the Detector, together with all necessary chargers, cables, earth spikes, etc. The accuracy and validity of data obtained with this method is dependent on the sophistication of design of the equipment which also significantly affects the surveyor/equipment interface in the field.

The signal generator should be a self-contained weatherproof unit powered by internal re-chargeable batteries that can operate in remote locations where an external power source may not be available. For prolonged operation, it is possible on most systems to augment the internal batteries with an external 12V DC power source (vehicle battery or similar). The signal generator should be to produce a fully stabilized AC signal at the selected frequency

Accurate survey results are primarily dependent on the analysis of relatively small differences in readings at successive locations. It is therefore essential that the input signal at the signal generator remains absolutely constant during the course of a survey. Once an appropriate output signal current has been selected by the operator, the signal generator should continue to output a constant current regardless of any changes of impedance in the external circuit, until the internal batteries or external power source are exhausted.

A1.3.2: Pre Survey Data Assembly

Before carrying out an electromagnetic current attenuation survey, it is advisable to collect as much as possible of the data listed below.

Pipeline Data

- Pipeline material (steel, cast iron, etc.) and grade.
- Diameter(s) and length
- Wall thickness.
- Product carried and operating pressure (nominal and maximum)
- Year manufactured.
- Type of coating
- Pipeline Construction Data –
- Year installed
- Route maps ('as built'), Arial photos
- Construction practices
- Road/rail/river/marsh crossings along pipeline route.
- Location of branches, valves, isolation devices (aboveground or underground), insulating joints, CP test posts, electrical junction boxes, sacrificial anodes, and CP ground beds.
- Location of casings/sleeves
- Pipeline depth (centerline and/or cover).
- Location and nature of all repairs and renovation (with dates) carried out over the last ten years.
- Location of all CP cross-bonds to other pipelines or structures indicating whether they can be disconnected.
- Existence of parallel pipelines and/or services in the pipeline corridor (right-of-way).
- Indication of any potential access barriers crossing the pipeline corridor (growing crops, dense undergrowth, fences, hedges, walls, or other structures)
- Soil chemical and physical properties.

Cathodic Protection System Data –

- Type of CP System (impressed current or galvanic/sacrificial anode)
- Number, locations and specifications of transformer/rectifier stations in the system.
- Type of anode beds/ground beds
- Historical data on CP System – CP current drain per mile/kilometer, CIS survey data, TR inspection data, CIS survey data, other CP system inspection data.
- Reports and results of all other surveys of the pipeline carried out in the last ten years.

A1.3.3: Survey Procedure

Before starting the survey it is essential that the operators carefully study the 'Operator's Manual' and any other material supplied by the manufacturer, together with relevant statutory or company regulations on operational health and safety. They should also check (against the packing list) that all the equipment, including spare batteries, is present. They must ensure that all periodic maintenance and charging procedures have been carried out and the equipment is in full working order.

WARNINGS: Before any connections are made to the pipeline it should be checked for any induced A.C. (from nearby HT power cables, AC traction systems, etc) High levels of induced A.C. could cause injury to any person who may act as a path to 'ground' by touching the pipeline or any lead or cable connected to it. Accidental 'earthing' of a strong induced A.C. current could also cause damage to some instruments and other equipment. Also, care must be used when operating this type of equipment on pipelines either inside the boundaries of, or connecting to facilities within, or even passing close by any airport. The nature of the AC signal being applied to the pipeline may have a serious adverse affect on the electronic systems used by the airport to communicate with and/or control aircraft in the vicinity.

The signal generator must be connected to the pipeline and to a suitable 'earth' point. Usually the best location for this is a transformer/rectifier CP station, making use of the CP ground-bed as the 'earth' connection, and the CP cable to the line as the 'pipe' connection. This must only be done <u>after</u> turning the transformer/rectifier off and disconnecting the CP cables from the ground bed and pipeline. If there is no T/R station in a suitable location, the signal generator can be connected to the pipeline via a CP test post (which connects to the pipeline). The 'earth' connection can then be set up nearby using one or more 'earth spikes' driven into the ground. This may not permit the applied signal to be as large as can be achieved using the T/R ground-bed, and the survey run may therefore be shorter.

Other possible connection points include block valves, insulating joints or other exposed sections of pipeline. The operator can then set the signal current. Detailed instructions for this will depend on the equipment being used and should be found in the manufacturer's 'Operators Manual'.

To minimize field interference, cables between the signal generator and the pipeline should be laid out at right angles to the pipeline, and the earthing point, whether ground-bed or earth spikes, should be at least 50 feet (15 meters) from the pipeline.

Survey Method

The first survey point – This should be at least 50 feet (15 meters) along the pipeline from the point where the signal generator is connected to the line. If the detector does not have integral GPS, a survey point should be selected which can be noted and used again for later surveys. The usual procedure is to approach the line at right angles until the detector indicates that it is precisely 'overhead'. For advanced systems, the operator is automatically guided to this position. For some other systems it may be necessary to make use of a standard pipe locator.

The detector should analyze the information collected by the antenna system together with the data entered by the operator, and display some or all of the following data:

- Overhead marker
- Survey reference, date, time and location number
- Depth of pipeline (cover or to centre-line)
- Pipeline diameter and wall thickness
- Strength of remaining signal current
- Latitude and longitude of present survey location (using GPS)

This data should be logged and, if possible, stored in the detector's computer. At each subsequent survey point (which may be several hundred meters or feet further along the pipeline) the detector should also display and store:

- Distance to any selected previous location (chainage or incremental)
- Signal attenuation rate over any section of pipeline
- Average coating conductance or resistance over the section (per sq.m or sq. ft.)
- If the equipment used does not generate, display and store this information automatically, the basic data must be noted down for later analysis.

The macro survey should continue with data collected at each survey location. Distances between survey points could be between 50 meters and 500 meters (150 -1500 feet) with even longer distances on lines with 'good' to 'excellent' coating. Any section indicating abnormally high attenuation may require additional readings to 'narrow down' the suspect section for subsequent 'micro' assessment to locate and evaluate individual faults.

The signal current remaining on the pipeline will reduce as the operator moves along the line. The rate of reduction will depend on the general condition of the coating. When the detectable signal falls below a useable level, it is necessary to move the signal generator to a new position and start the next 'leg' of the survey. The operator should ensure that there is an element of overlap between successive survey 'legs'.

When a general ('macro') survey has been completed, all survey data may be viewed on the detector LCD and it may be saved or downloaded to a computer for further analysis and printout in graphic or tabular form (if this facility is available on the system being used). Comparisons with previous survey profiles of the same pipeline may also be displayed to highlight areas of recent damage or deterioration over time. This operation can be carried out automatically with advanced current attenuation survey systems.

The printed-out survey report may indicate sections with unacceptably high attenuation levels and these may be the subject of 'micro' (close interval) surveys to locate and evaluate individual coating faults (holes and mechanical damage, general physical deterioration, porosity, cracking, contact with other buried services, etc). These faults may be located using different ground contact survey systems, provided good electrical contact with the ground can be achieved. Alternatively some current attenuation systems can be switched into 'close interval' (micro mode) to carry out this task, particularly where ground contact may be difficult. In micro mode, readings of 'current only' are taken at intervals of 2-3 meters (6-10 feet) over a 'suspect' section (say 75-100 meters – 200-300 feet). All the readings for each short survey are shown graphically and simultaneously on the LCD with the length of the baseline constantly adjusted to accommodate the readings. The location and significance of the individual faults can usually be clearly identified in this display

A1.3.4: Data Validity

The validity of the data generated is dependent on eliminating any possible causes of error to achieve the highest levels of accuracy and consistency in the readings recorded. Amongst the features necessary to obtain this in the most advanced current attenuation survey systems, are the following:

Applied signal current – The strength of the initially applied signal current must remain absolutely constant throughout the survey, since the determination of 'attenuation rate' and hence coating condition is determined by the ratio of one survey location reading to the next. A change of applied current due to small changes in ground resistance as the instrument is being moved between readings could produce a false reading of 'attenuation rate' and hence coating condition. It is therefore essential that the applied signal is constantly monitored and kept at the level set by the operator.

Operating frequencies – These should be crystal generated to maintain consistency of output and the operating frequencies selected must avoid, as far as possible any harmonics found with common ambient signals arising from other sources (50Hz, 60Hz, 100Hz, 120Hz, etc. etc.).

Antenna design – current attenuation systems use two or more groups of coils or other transducers that can derive the 'true' values of field strength and direction at every point, using the vector sum of the fields recorded. The overall length of the antenna assembly has been increased as far as is practicable with a hand-held 'field' instrument. This has produced further improvements in the accuracy of determination of 'depth' and 'current'.

Signal filtration – advanced detectors use very narrow band reception filters to minimize interference, and can 'warn' the operator if they receive large or anomalous transient signals (from 'above ground' sources, from AC traction systems, etc). In general, these will be 'ignored' by the system since it automatically analyses a large number of readings over several seconds before accepting them and proceeding to the next stage of calculation.

A1.3.5: Data Format

The format of the survey output will depend on the type of instrument being used. For a basic instrument, the information is noted down during the course of the survey - survey reference, location number, and distance from previous location (using road-wheel), and signal strength and pipeline depth. For a short survey with a strong signal, on a straight pipeline at a constant depth of about 1 meter (3 feet), this could be useful in indicating major problems, but would be of limited value for a long 'condition' survey, where pipeline depth may vary, and there would be rapid loss of accuracy with increasing depth or a low signal.

The more advanced current attenuation survey systems can automatically generate a range of timed and dated reports including the following:

- A point-to-point GPS 'map' of the pipeline showing all survey points
- A graphic plot or table showing the depth of the line
- ('cover' or to centre-line).
- A graphic plot or table showing signal current values for each survey location.
- A graphic plot or table showing absolute signal attenuation values, section by section.
- A graphic plot or table showing coating conductance or resistance (per sq. meter or sq. foot), section by section.
- A short range graphic plot of 'current' values for accurate fault location and evaluation when operating in close interval 'micro' mode.
- A table of pipeline identification information, survey equipment settings, and raw survey data with field notes recorded by the detector computer.

A1.4: Soil Models

Soil models have been developed to assist pipeline operators with the relative characterization of potentially significant SCC susceptible and non-significant SCC susceptible terrain conditions within a pipeline system. . A SCC Susceptibility Model is based upon the analytical results of extensive investigative excavations (i.e. SCC sites) and data compiled by pipeline owner/operators. The reliability and validity of any SCC Susceptibility Model is based upon investigative excavations and two important assumptions: disbonded coating and a susceptible line pipe steel.

The primary function of a SCC Susceptibility Model is not intended to predict the location of near critical SCC flaws or the next failure, but instead enables the identification of potential SCC susceptible areas along a pipeline. The practicality of a SCC Model allows valve sections or areas within a pipeline segment or system to be prioritized according to potential SCC susceptibility.

- A soil model is developed by combining terrain study information with available pipeline materials, construction and maintenance information.

The intuitive display allows the soil model user the ability to visualize numerous datasets at once and make educated integrity decisions quickly and decisively.

Attachment 2: AVAILABLE DIRECT EXAMINATION TECHNIQUES

Technical Background

A2.1: Investigative Excavations

Investigative excavations are to be used for direct validation of suspect anomalies identified during the pre-assessment or indirect inspection. Also, investigative excavations are to be used for validation of the DA methodology by direct examinations conducted at random sites not suspect or of concern (i.e. prove the null hypothesis). This involves uncovering short sections of pipeline (a minimum of one joint) at the locations considered most likely to contain an anomaly based on the indications completed during both the pre-assessment and indirect surveys. If anomalies are discovered that are severe enough to pose a threat to integrity in the future, then remedial action is taken. Severity of anomalies is to be determined using the repair criteria as delineated in the EMPCo Integrity Management Program Manual.

With the pipeline uncovered, the following direct inspections are required:

- classify and document terrain conditions (topography, soils, and site drainage) according to criteria developed by the DA service provider.
- assessment and documentation of coating conditions.
- sample and document pH values of electrolyte found beneath the pipeline coating.
- identify areas of coating disbondment for subsequent NDE analysis
- complete inspection of welds, long seams and areas of known or related integrity threats based on pipe manufacture or construction practices
- document and assess all detected integrity threats using internal or external codes, standards or procedures.
- incorporate findings into a database designed specifically for direct examinations
- adapt results for existing integrity programs as needed.

A2.2: Terrain Analysis

At each investigative site, the terrain conditions are recorded as the pipeline is excavated. The documentation of terrain conditions includes the identification of soil type, drainage, and topography parameters. Definitions and terms used by the DA service provider in the documentation of the terrain conditions at each investigative site are based on existing governmental (i.e. Agriculture Canada and USDA) procedures. The Canadian Energy Pipeline Association (CEPA) has adopted this classification system.

A2.3: Soil Type

The soil type classified at each investigative site is based on the mode of deposition and texture. Table A2.1 below lists the various soil environment descriptions:

Table A2.1: Soil Type Classifications

Soil Type	Description
Glaciofluvial/Fluvial	Sorted and stratified, sandy and/or gravel-textured material, which includes alluvial sand and gravel derived from relict watercourses.
Till (Morainal)	Variable soil texture with a variable-size range of unsorted stones. Includes gravel, sand, clay, and silt that were glacial in origin.
Lacustrine	Typically fine-textured deposits, clay to silt, with well-defined stratification. Deposits are formed in standing bodies of water.
Alluvial	Commonly rocky, gravel-textured sediment that is stream-derived.
Eolian	Wind-derived material, usually fine to very fine textured sands.
Organic	Partially decomposed organic material.

A2.4: Soil Drainage

The soil drainage is determined at pipe level based on soil characteristics such as depth of mottling and gleying or the absence of soil drainage impediments from the soil surface. Listed below are the definitions of drainage classifications identified at each site:

Table A2.2: Soil Drainage Classifications

Drainage Type	Description
Well Drained (W)	Oxidizing environment throughout the year.
Imperfectly Drained (I)	Alternating oxidizing and reducing environment. The environment is dependent on fluctuation of the water table.
Poorly Drained (P)	Primarily reducing conditions. The environment may be saturated throughout most of the season.
Very Poorly Drained (VP)	Reducing conditions throughout the entire year. The environment is saturated year-round.
Very Poorly – Very Poorly Drained (VP-VP)	Reducing conditions throughout the entire year. The soil consists of organic material and the environment is saturated year-round. Standing bodies of water are present on surface topography.

A number of factors can help determine the drainage of the soil. They are:

- Presence of an organic layer;
- Water table depth;
- Presence, abundance, and depth of mottles in the mineral soil; and
- Presence and depth of gley colors in the mineral soil.

The presence of a layer of organics on top of the mineral soil can also be indicative of the soil's drainage. A layer of 40 cm or more of organics indicates a very poorly drained soil.

Seasonal changes in the water table need to be considered when determining drainage. For example, if the water table depth is above the top of the pipe throughout the year in a mineral soil, the drainage can be classified as very poor.

Mottling of the soil appears as a blotches or spots of a different color or shade of color generally yellow to red hues than the main soil color. Mottled soils are indicative of a fluctuating water table, which produces alternating reducing and oxidizing conditions, and are mainly associated with imperfect or poorly drained soils.

Gleying of the soil appears as a gray to blue or green color within the soil matrix. Gleyed soils are indicative of saturated or reducing conditions throughout the year, and are mainly associated with poorly or very poorly drained soils.

The soil profile does not need to exhibit mottling or gleying if the drainage is imperfect, poor, or very poor.

A2.5: Topography

The topography at each site is documented according to the landscape pattern. Listed below are the topography and site position classifications used during each investigative program:

Table A2.3: Topography Classifications

Topography	Description
Undulating (U)	Regular sequence of gentle slopes from alternating concave and convex patterns.
Ridged I	Sharp crested or dome shaped.
Inclined (I)	Sloping surface.
Level (L)	Flat to very gently inclined.
Depressed (D)	Topographically low-lying area.
Side Slope (S)	Side slope of an incline, perpendicular to the pipeline right-of-way.

A2.6: Site Position on a Slope

The location of the site was identified with respect to local topography according to the following criteria:

Table A2.4: Site Position Classifications

Site Position	Description
Crest	The uppermost portion or apex of a slope.
Upper Slope	The uppermost portion of a slope immediately below the crest.
Middle Slope	The area between the upper and lower slope.
Lower Slope	The lower portion of the slope immediately above the toe.
Toe	The lowermost portion of the slope.
Depression	Any area that is concave in all directions.
Level	Any level area.

A2.7: Carbonates

The presence or absence of carbonates (CO_3^{2-}) within a soil profile is indicative of the carbon dioxide (CO_2) levels in the pipeline environment. Near neutral pH stress corrosion cracking (SCC) has been associated with soils with higher levels of CO_2, which forms carbonic acid, a weak acid within the pipeline environment.

A2.8: Soil Resistivity

Soil resistivity is measured using the Wenner 4 pin method. Higher soil resistivity may prevent CP current from reaching the pipeline.

A2.9: Coating Assessment

After the pipe is excavated, the pipeline coating condition is inspected and documented at each investigative site. In most cases, the furthest upstream girth weld is located to provide a reference point and all subsequent measurements are referenced to it. This girth weld is referred to as the reference girth weld, and is located between joint AA (upstream) and joint A (downstream). Personnel from the DA Service provider can identify and document the long seam (or other weld type) and girth weld positions at each site.

On a joint-by-joint basis, the coating condition is identified and documented. The coating conditions that are documented include areas that are well bonded, areas of disbondment, tented regions across welds, and locations of holidays. Below, Table 5 outlines the general definitions used to qualitatively characterize pipeline coating conditions:

Table A2.5: Qualitative Condition Descriptions

Coating Condition	Description of Disbonded Coating	Common Corrosion Deposits Pattern
Excellent	Very good adhesion; continuous thickness; <1% disbondment; an occasional holiday.	None
Good	1 to 10% disbondment; scattered holidays; good adhesion.	Spotty
Fair	10 to 50% disbondment; scattered to numerous holidays; random areas of poor adhesion.	Spotty to Intermittent
Poor	50 to 80% disbondment; numerous holidays; multiple or long areas of poor adhesion.	Intermittent to Continuous
Very Poor	>80% to total disbondment; numerous holidays; no adhesion, brittle coating.	Continuous to Dense

The description of the coating condition is correlated to the terrain conditions on a per-joint basis, allowing the DA Service Provider to determine the probability of similar coating conditions throughout a pipeline system.

A2.9: Corrosion Deposits and Electrolytes

Upon removal of the coating, the presence or absence of corrosion deposits is noted. Documentation of the corrosion deposits includes the color, texture, and distribution. These physical properties assist with identification of the corrosion deposits in the field.

Common corrosion deposits found beneath pipeline coatings can include:

- White, pasty iron carbonate ($FeCO_3$) - anaerobic, strong association with SCC, cathodic shielding and external corrosion;
- White, powdery calcium carbonate ($CaCO_3$) - indicative of a functioning CP system;
- Black, metallic/hard/pasty/powdery iron sulfide (FeS) - indicative of the presence of sulfate reducing bacteria (SRB);
- Orange/gray, powdery/scaly/film iron hydroxides and oxides (FeO, Fe_3O_4, FeO/OH) consisting of magnetite, maghemite, goethite, and lepidocrocite - variable aerobic/anaerobic conditions.

In order to properly assess an investigative site and its relationship to environmental conditions and integrity concerns, it is necessary to correctly identify corrosion deposits and the pH of the electrolyte beneath the disbonded coating. When combined with other specific environmental parameters, certain corrosion deposits are indicative of either the presence or absence of SCC, external wall loss, and microbial induced corrosion.

In the event that electrolyte is present between the surface of the pipe and coating, its location and properties are recorded. Electrolyte color is recorded and electrolyte pH is visually measured using pH litmus paper. Non-classical SCC is commonly associated with an electrolyte pH reading between 6.0 and 8.5; classical SCC is known to be associated with an electrolyte pH range between 9.0 and 11.0. SCC is not known to occur when the electrolyte pH is greater than 11.0.

If the presence of bacteria is suspected, corrosion deposit samples are collected and analyzed by population density, general bacteria type (SRB or APB), and by-product type (i.e. type of organic acid).

A2.10: Pipe-to-Soil Reading

A voltmeter and a $Cu/CuSO_4$ electrode are used during an investigative excavation to obtain CP readings at the 12:00 o'clock, 3:00 o'clock, 6:00 o'clock, and 9:00 o'clock positions at regular intervals along the pipeline. For short excavations, the readings will be taken at the upstream and downstream ends of the excavation. These readings will show whether the CP is reaching all areas of the pipeline or if there is any CP drop over the length of the excavation

A2.11: Non-destructive Testing

Following the completion of the terrain, coating, and corrosion deposit assessments, the pipe is prepared for MPI. Areas inspected typically include:

- Girth welds and associated pipe on either side of the weld;
- Long seams and associated pipe on either side of the weld;
- Coating holiday locations; and
- Disbonded coating areas.

The pipe is prepared for MPI (ASTM E709 Standard) with a high-pressure air blasting system that uses an abrasive substance consisting of crushed walnut shells, glass beads, or another accepted medium. The air blast system must be of sufficient size to produce 100 psi at the blast tip. This procedure is conducted under the guidance of qualified personnel and is conducted to remove any remaining coating, primer, and/or corrosion deposits from the pipe surface that may hinder the MPI and the identification of SCC or other pipe surface anomalies.

A2.12: Magnetic Particle Inspection

The DA service provider shall use one of two methods to detect SCC on ferromagnetic steel pipelines: Wet fluorescent magnetic particle inspection (WFMPI) and black on white contrast magnetic particle inspection (BWMPI). Both inspection methods are proven procedures for detecting external SCC and other surface anomalies.

Comparatively, the WFMPI method is more economical and generally less time consuming than BWMPI. However, BWMPI is required to document and photograph any external discontinuities detected. BWMPI is a favorable inspection method for short excavations (i.e. less than one full joint length) or if the site is excessively wet. If the ambient air temperature is above 20° Celsius, BWMPI is also the preferred inspection method due to the possible fatigue of inspection.

If any SCC colonies or other surface indications are detected on the pipe, each individual colony or indication is measured and documented by Marr personnel, except when physical constraints hinder this action (i.e. beneath the pipe in tight locations). The depth of all detected SCC colonies are then visually estimated as a throughwall percentage of the pipe wall thickness.

In the event that SCC colonies are detected during the MPI inspection, selected SCC colonies will be removed by buffing. The colonies are buffed out using a grinder with a rubber-backed sanding disc. The reasons for buffing the SCC colonies are to:

- Verify the visual depth estimate;
- Verify the actual depth of the SCC colony; and
- Remove the colony from the pipe wall.

To determine the crack depth, UT wall thickness measurements are made before and after the colony is removed. The difference between the two readings is the throughwall depth of the colony, which is then recorded as both a percentage of the pipe wall thickness and in terms of millimeters.

SCC colonies occurring near or within external corrosion features are also evaluated. The SCC colonies near external corrosion are documented with the procedure outlined above, but the occurrences within external corrosion must be evaluated in conjunction with the depth of corrosion.

SCC colonies in external corrosion are usually visually estimated for depth. UT wall thickness measurements are made in the corrosion feature to determine the remaining wall thickness. The corrosion's throughwall depth and the SCC colony depth are both considered in determining the overall depth of the SCC colony. The procedure for documenting external corrosion is explained in the proceeding section.

A2.14: Corrosion Feature Assessment

To accurately document an external corrosion feature, a reference point is defined as the upper left corner of the feature. This reference location is defined as the distance from the girth weld and the circumferential distance from the top of the pipe. The overall axial and circumferential lengths of the feature are recorded. The corrosion feature is then prepared for mapping by superimposing a grid over the entire anomaly area. The grid size utilized is dependant on client preference, but typically, a 1 to 3 cm grid is used to delineate the corrosion feature area. UT techniques or mechanical gauges are used to obtain the remaining wall thickness readings at each grid reference node, both axially and horizontally along the pipe. The wall thickness readings are recorded in a spreadsheet.

A pit depth gauge is used to map the depth of the corrosion feature. The two edges of the pit gauge, which extend out 2 inches on either side, must be positioned on uncorroded pipe in order to obtain an accurate pit gauge reading. This procedure allows the corrosion depth to be assessed in reference to the original outside diameter of the pipe. In the event that the corrosion feature is extensive, a bridging bar is required in order to obtain representative readings. The bridging bar is positioned on the pipe so that measurements are calibrated from a flat surface.

UT pencil probe measurements are made using a ¼ in. ultrasonic transducer with a conical delay line of 1/8 in. diameter at the tip. Pencil probes measure the remaining wall thickness, while the pit gauge measures the corrosion depth. The pencil probe method is more versatile than the pit gauge technique because it is not limited by the requirement of a flat, uncorroded pipe surface to bridge the pit gauge across.

A2.15: Guided Wave Ultrasonic Testing - GWUT

The Guided Wave Ultrasonic Testing (GWUT) system is capable of characterizing long runs of pipe from a single set-up point. GWUT is a low frequency ultrasonic tool that can detect wall thickness variations in pipe up to 250 linear feet in either direction from a single inspection point. This method requires that coating and/or insulation be removed or access provided to only 24 inches of clean pipe with 6 inches clearance above and below circumferentially.

The tool can handle pipe sizes down to two (2) inches in diameter. The largest diameter pipe that can be inspected at the present time is 60 inches. This method has proven to be cost effective for inspections of piping at the soil-to-air interface and at road crossings where excavation would be costly and time consuming. Other applications are overhead lines where scaffolding would be required, on insulated lines where insulation removal would be time consuming or hazardous (asbestos), and for corrosion under insulation (CUI) inspections.

This method also provides a cost effective solution for assessing the unpiggable sections of pipelines. The technique has been employed on buried sections of pipe and routinely achieves inspection distances of 90 to 100 feet in each direction from the bell hole. Special techniques have also been developed that yield good results on lines that penetrate concrete walls going to a buried pipe section. One of the side benefits of utilizing the system is locating the position of welds along buried or insulated lines. This can be valuable information relative to corrosion mechanisms operating on a line and in locating and verifying signals received from questionable areas along the line.

Attachment 3 : EXECUTION

A3.0 Pre-Screening

A3.0.1 Identification of Candidate DA Pipeline Segments

Pipeline segments that are likely candidates for DA are identified from the HCA database or identified by field operations units. These candidate pipeline segments usually have some or all of the following attributes:

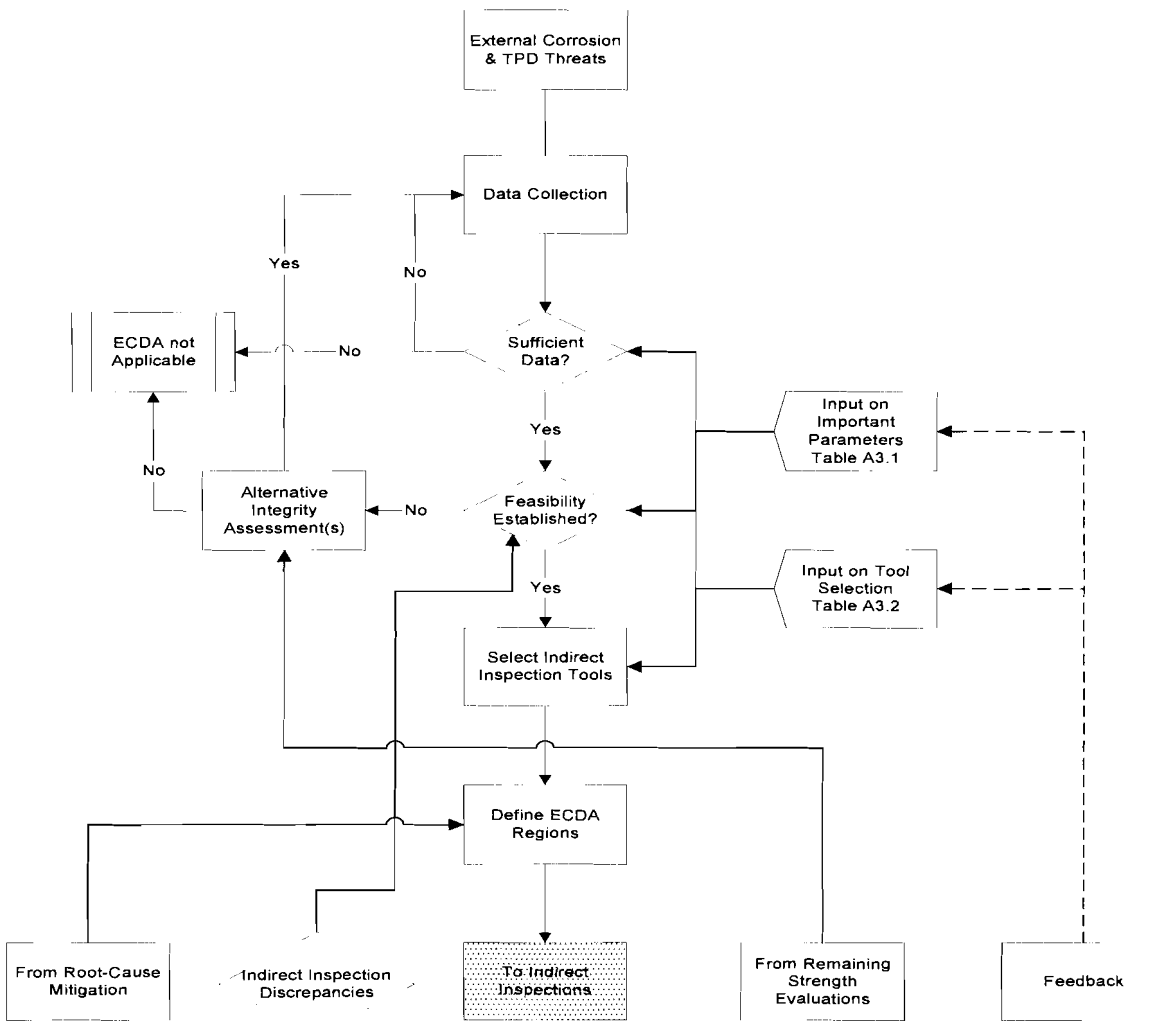
- Short length (normally less than a mile)
- No pig launching or receiving capabilities or impediments to smart pigging (internal coating)
- Difficulty in obtaining shutdown of the segment
- Little or no tolerance for entrained water
- Not susceptible to long seam failure
- Not susceptible to internal corrosion *
- Not susceptible to SCC *
- Transported material not compatible with ILI tools (pipe ID buildup, etc.)
- Readily accessible for indirect inspection techniques (no major waterway crossings, able to be traversed by foot, etc.)
- Coating compatibility with Indirect Inspection Techniques
- Good records of pipeline installation and operation including specifications, materials, coating (ECDA not applicable to bare pipe or disbonded, monolithic coating), inspection records, and leak history
- This list is not inclusive, other difficulties could render DA not applicable. Conversely, a pipeline segment could have attributes that initially make it a difficult line to assess with DA but the difficulties may be overcome with more extensive Indirect Inspection Tool (IIT) or Direct Examination methods.
- DA Technology and methodologies to evaluate Internal Corrosion and Stress Corrosion Cracking not available at the time this document was prepared.

A3.1 Pre-Assessment:

A3.1.1 Objectives:

- Collect the needed pipeline data to determine the feasibility of conducting DA
- Determine the feasibility of conducting DA for the pipeline segment
- Select Indirect Inspection Techniques (IIT)
- Establish ECDA Regions
- Document Pre-Assessment Results

Figure A3.1: Pre-Assessment Flow Chart



See Figure A3.2 (Indirect Assessment) for Continuation

A3.1.2 Data Collection

The following data sets should be investigated and attempts made to find any applicable records to fill in information:

Table A3.1: Direct Assessment Data

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Pipe Data				
Material and Grade	ECDA not applicable to non-ferrous materials	Consideration to locations where dissimilar metals join	Can create local corrosion cells	Required
Diameter	May reduce detection capability of IIT		Influences currect flow and interpretation of results	Required
Wall Thickness			Impacts critical defect size and remaining life predictions	Required
Year Manufactured			Older pipe materials may have lower toughness levels, reducing critical defect size and remaining life calculations	Consider
Seam Type	ECDA not applicable to seam failure susceptible pipe	Increased selective seam corrosion suscepotibility may require separate ECDA regions	Older pipe may have lower toughness in seams or be more susceptible to seam selective corrosion	Required
Bare Pipe	Limits ECDA tool selection	Bare pipe should be a separate region from coated pipe	See Attachment 1 for applicable ECDA methods	Required

Required = Data that must be available or be acquired during the DA process for ECDA Applicability

Desired = Data that is helpful to the DA Process, but may be obtained during the DA process

Consider = Data that is potentially helpful to the DA process but not required

Example: Depth of cover is Desired to be available during pre-assessment but will be obtained during the DA process anyway, therefore that data is not Required prior to performing the DA process.

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Construction	**Data**			
Year Installed			Impacts time over which coating degradation could occur, defect population estimates, corrosion rate estimates	Required
Route Changes/ modifications		Changes may require separate DA regions		Desired
Route Maps/Aerial Photos		Provides general applicability information and DA region selection	May contain pipe data that could help facilitate DA	Desired
Construction Practices		Differences in construction methods could require separate DA regions	May indicate locations where construction problems may have occurred, backfill practices influence coating damage	Desired
Locations of Valves and other major appurtenances		Significant changes in CP current could occur, consider dissimilar metals	May impact local current flow and interpretation of results, dissimilar metals could create local corrosion cell, coating degradation rates may be different	Desired
Location of casings and construction methods	May preclude use of certain IIT	Requires separate DA region	May require operator to extrapolate nearby results to inaccessible regions. Additional tools could be required	Required

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Construction	**Data (continued)**			
Location of bends		Presence of miter or wrinkle bends may influence DA Regions	Coating degradation may be at different rates, corrosion on bends can be localized, affecting local current flow and interpretation of results	Desired
Depth of Cover	Restricts the use of some IIT	May require separate DA regions	May impact current flow and interpretation of results	Desired
Underwater sections	Significantly restricts the use of many IIT	Requires separate DA regions	Changes current flow and interpretation of results	Required
Road and river/marsh crossings	Restricts the use of some IIT	May require separate DA regions	May impact current flow and interpretation of results	Desired
Location of river weights and anchors	Restricts the use of some IIT	May require separate DA regions	May impact current flow and interpretation of results, corrosion near weights and anchors can be localized	Desired
Proximity to other pipelines, structures, high-voltage electric transmission lines, rail crossings	May restrict the use of some IIT	Regions where the CP currents are significantly affected by external sources should be treated as separate DA regions	May impact current flow and interpretation of results	Desired

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Soils and	**Environmental**			
Soil Characteristics	Some soil characteristics reduce the accuracy of various IIT	Influences where corrosion is most likely, significant differences require separate DA regions	Useful in interpreting results. Influences corrosion rates and remaining life assessment	Desired
Drainage		Influences where corrosion is most likely; significant differences require separate DA regions	Useful in interpreting results. Influences corrosion rates and remaining life assessment	Desired
Topography	Conditions such as rocky areas can make IIT inspections difficult or impossible			Desired
Land Use (current and past)	Paved roads, etc. Influence IIT selection	Can influence DA application and region selection		Required
Frozen Ground	May impact applicability and effectiveness of some DA methods	Frozen areas should be considered separate DA regions	Influences current flow and interpretation of results	Required
Corrosion	**Control**			
CP System Type (anodes, rectifiers, locations)	May effect IIT DA tool selection		Localized use of sacrificial anodes within impressed current systems may influence current flow and interpretation of results	Required

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Corrosion	**Control (cont'd)**			
Stray current source/location			Influences current flow and interpretation of results	Desired
Test point locations (or pipe access points)		May provide input to DA region selection		Required
Foreign pipeline crossings		May provide input to DA region selection	Influences current flow and interpretation of results	Desired
CP Cross Bonding to other pipelines or structures		May provide input to DA region selection	Influences current flow and interpretation of results	Required
CP evaluation criteria			Used in post assessment analysis	Required
CP maint. history		Coating condition indicator	Can be useful in interpreting results	Desired
Years without CP applied		May make DA more difficult to apply	Negatively affects ability to estimate corr. rates and make remaining life predictions	Desired
Coating type - pipe	ECDA may not be applicable to disbonded coatings with high dielectric constants, which can cause shielding		Coating type may influence time at which corrosion begins and estimates of corrosion rates based on measured wall loss	Required

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Corrosion	**Control (cont'd)**			
Coating type - joints	ECDA may not be applicable to coatings which can cause shielding		Shielding due to certain joint coatings may lead to requirements for other assessment activities	Desired
Coating condition	DA may be difficult to apply with severely degraded coatings			Desired
Current demand			Increasing current demand can indicate areas where coating degradation is leading to more exposed pipe surface	Desired
CP survey data/history			Useful in interpreting results.	Desired
Operational	Data			
Pipe Operating Temperature		Significant differences generally require separate DA regions	Can locally influence coating degradation rates	Desired
Operating stress levels and flunctuations			Impacts critical flaw size and remaining life predictions	Required
Pipe inspection reports - excavations		May provide input when defining DA regions		Required

A3.1.2 Data Collection (continued)

Table A3.1: Direct Assessment Data (continued)

Data Element	Indirect Inspection Tool (IIT) Selection	ECDA Region Definition	Use and Interpretation of Results	Need
Operational	**Data (continued)**			
Monitoring programs (coupons, patrols, leak detection, etc.)		May provide data when defining DA regions	May impact repair, reemediation, replacemetn schedules	Desired
Repair history/records (sleeves, locations, etc.)	May affect DA IIT selection	Prior repair methods, such as anode installations, can create a local difference that may influence DA region selection	Provides useful data for post assessment analyses such as interpreting data near repairs	Desired
Leak/Rupture history		Can indicate condition of existing pipe		Required
Evidence of external MIC			MIC may accelerate external corrosion rates	Desired
Third Party Damage freq.		Critical to detemine TPD threat risk	High TPD areas may have increased IIT coating faults	Required
Data from previous IIT surveys			Essential for preassessment and DA region selection	Required
Hydrotest dates & pressures			Influences inspection intervals	Desired
Land Use		Could indicate TPD risk	changes affect TPD risk	Desired
Other prior integrity related activities (CIS, ILI results, etc.)	May impact IIT selection - isolated versus larger corrosion areas		Useful post assessment data	Required

A3.1.3 Feasibility Assessment

The amount and quality of data collected in the pre-assessment shall be used by the Field Steward and/or the Qualified Individual to determine if the DA process can reasonably be applied to the pipeline segment. If conditions are such that DA is not applicable, the Field Steward shall make the appropriate HCA schedule change due to assessment method change (and probably timing as well).

Table A3.2: ECDA Tool Selection Matrix

CONDITIONS	CIS	DCVG/ACVG	ACCA	GWUT
Coating holidays	Yes	Yes	Yes	No
Anodic zones on bare pipe	Yes	No	No	Yes
Near river or water crossing	Yes	No	Yes	Yes
Under frozen ground	No	No	Yes	Yes
Stray currents	Yes	Yes	Yes	No
Shielded corrosion activity	No	No	No	Yes
Adjacent metallic structures	Yes	Yes	Yes	No
Near parallel pipelines	Yes	Yes	Yes	Yes
Under high voltage AC electric lines	Yes	Yes	No	Yes
Shorted casings	Yes	Yes	No	Yes
Under paved roads	No	No	Yes	Yes
Uncased crossing	Yes	Yes	Yes	Yes
Cased piping	No	No	Yes	Yes
At deep burial locations	Yes	Yes	Yes	Yes
Wetlands	Yes	Yes	Yes	Yes
Rocky terrain/backfill	No	No	Yes	Yes

A3.1.4 Indirect Inspection Tool Selection

A minimum of two complete IIT methods shall be employed for the entire length of the pipeline segment to be assessed by DA. Tools shall be selected based upon their ability to detect corrosion activity and/or coating faults reliably under conditions present for the specific pipeline being assessed. Tools shall also be selected based upon their compatibility with each other. A 100% direct examination that follows the requirements of Attachment 2 of this document in lieu of indirect inspections combined with direct examinations can be substituted where feasible. Pre-Assessment and post assessment steps are still required when substituting 100% direct examination for indirect inspections. Table A3.2 can be used to assist in the IIT decision making process. In some cases 3 or more Indirect Inspections techniques may be required to get acceptable IIT results. The DA Service Provider shall notify the DA Field Steward if more than 2 IIT surveys are required.

A3.1.5 Identifications of DA Regions

The DA service provider will analyze the data collected in the Pre-Assessment step to identify DA Regions. A DA Region is a portion of a pipeline segment that has similar physical characteristics, corrosion histories, expected future corrosion conditions, and that uses the same Indirect Inspection Tools. All conditions that could significantly affect corrosion will be considered by the DA service provider when defining DA regions using Tables A3.1 and A3.2 of this section as well as other information provided by the DA service provider and EMPCo personnel. DA region definitions may be modified based upon results of the Indirect Inspections and the Direct Examinations. A DA region does not need to be contiguous, it may be broken for a river crossing but extend on either side of the crossing. An entire pipeline segment could also be one contiguous DA region. Once the DA service provider has determined the DA region(s) for a particular pipeline segment, it shall be reviewed with the Field Steward and modifications made as desired. DA regions should be documented at the end of the Pre-Assessment Step of DA by the service provider and that documentation modified as necessary during Indirect Inspections and Direct Examinations. A final document delineating the DA regions used in the assessment will be located in the final report by the DA service provider.

A3.1.6 Pre-Assessment Review Meeting

A meeting between the DA service provider and the Field Steward (and other data sources as necessary) will be held to answer any questions the DA service provider has remaining about the data, interview those with knowledge of the pipeline segment, and advise of the proposed selection of DA regions and IIT equipment for each region of the pipeline segment that have been selected. Expected outcome of this meeting is finalization of the DA region selection and IIT methods to be used. It is expected that the DA service provider should conduct the Pre-Assessment meeting and have identified DA regions and IIT proposed surveys within one month of approval from the Field Steward to begin a DA assessment. Integration of the pre-assessment data is critical in determining applicability of the DA process and in determining the applicable threats identified from the history of the pipeline segment. In some cases, the amount and quality of the data available on the pipeline segment may invalidate its selection as a candidate for DA. In all cases, the outcome of the Pre-Assessment shall be documented in a detailed report provided by the DA Service Provider.

A3.2 Indirect Inspections

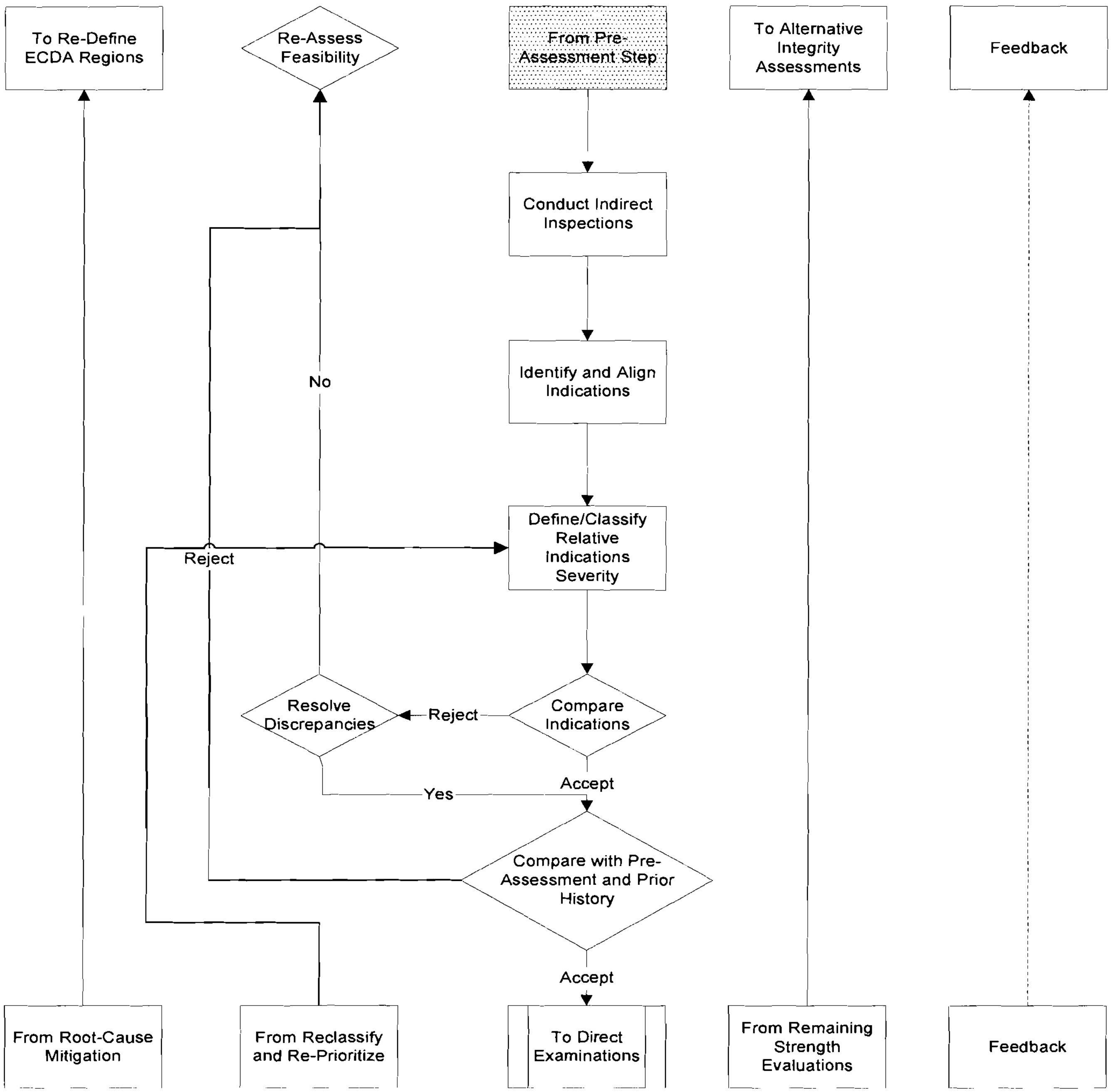
A3.2.1 Objectives:

- Locate and define the severity of coating faults, other anomalies, and areas where external corrosion and third party damage may have occurred.
- Conduct at least two indirect inspections over the entire pipeline segment
- Align and compare the results from the IIT surveys
- Identify and classify indications
- Analyze and report results for the Direct Assessment Step

A3.2.2 Conducting and Aligning the IIT Surveys

Boundaries of each DA region should be clearly identified and marked in the field for reference while performing IIT. Consideration to overlapping IIT across the DA region boundaries should be made by the DA service provider for completeness of data gathering. Additional IIT surveys may be determined to be necessary during the Indirect Inspection Step if IIT equipment does not perform as predicted or if different conditions are found that negates the accuracy of the IIT methods chosen in the Pre-Assessment Step. IIT methods shall be performed per the attached Appendix 1. The Indirect Inspection Step shall follow the attached Indirect Inspection Flow Chart Figure A3.2. When DA is applied for the first time, EMPCo and the DA service provider should consider spot checking, repeating IIT surveys, or other verification measurements to ensure consistent data is collected. IIT survey data points shall be conducted using intervals spaced closely enough to permit a detailed assessment, with the goal to use the IIT such that coating defects, possible corrosion, and anomalies can be detected with reasonable certainty. Normally, IIT survey data points shall be collected in spacing from 2.5 to 10 feet along the length of the pipeline. In some cases and with some IIT surveys, initial spacing can be more than 10 feet provided that detailed IIT surveys are conducted in areas with coating fault indications or in areas with suspect indications.The separate IIT surveys should be conducted as close in time as practical to avoid weather changes and changes normally occuring to CP systems over a longer period of time. If significant changes occur between the IIT surveys (such as a change of seasons or a change in pipeline configuration) comparison of results will be affected and may become difficult or invalid. Aboveground location measurements should be referenced to consistent geographic locations (for instance using GPS Coordinate systems) and so documented so that inspection results can be compared and used to identify excavation locations and for future reference. Overlay of IIT surveys shall be aligned on a common mapping system such as a Geographic Information System.

Figure A3.2: Indirect Inspection Flow Chart
(continuation of Fig. A3.1: Pre-Assessment Flow Chart)



(Continued on Direct Inspection Flow Chart: Fig. A3.3)

A3.2.3 Defining and Classifying Indication Severity

Classification of anomalies identified during the Indirect Inspection Step is a process of estimating the likelihood of corrosion activity at each indication under typical year-round conditions. Anomalies shall be classified according to the following:

Severe: Indications that the DA service provider considers as having a high likelihood of corrosion activity or a high likelihood of TPD.

Moderate: Indications that the DA service provider considers as having possible corrosion activity.

Minor: Indications that the DA service provider considers as having a low likelihood of corrosion activity.

The criteria for classifying the severity of anomalies shall take into account the capabilities of the IIT used and the unique conditions of the DA region examined. When DA is used for the first time, indications that the DA service provider cannot determine whether corrosion is active shall be classified as severe. The following Table A3.3 gives example severity criteria to be used for the IIT methods identified in Appendix 1 of this document. The table is a general guideline and not meant to be absolute. The DA service provider must consider specific conditions along the pipeline and the accuracy of the inspection methods when classifying indications. The DA Service Provider shall give special attention to the location of coating failures or stray currents in areas where TPD could be expected (such as in areas of foreign line crossings or subsurface construction or in areas of shallow cover with farming operations).

After indications have been identified and classified, the DA service provider shall compare the results from the separate IIT methods to determine consistency. If two or more IIT indicate significantly different sets of locations at which corrosion activity may exist and if the differences cannot be explained by the inherent capabilities of the tools or specific and localized pipeline features or conditions, additional indirect inspections or preliminary direct examinations should be considered. Preliminary direct examinations may be used in lieu of additional IIT surveys provided the direct examinations identify a localized and isolated cause of the discrepancy(s). If additional IIT surveys or Direct Examinations do not resolve the discrepancies, DA feasibility should be re-assessed. During initial DA applications, locations at which discrepancies cannot be resolved shall be treated as a severe indications. Locations with indications at foreign line crossings or other areas where a high likelihood of TPD exists shall also be treated as severe indications. Once IIT discrepancies are resolved, the DA service provider shall compare the IIT survey results with the Pre-Assessment results and prior operating history for each DA region and the entire pipeline segment being assessed. If the IIT surveys are not consistent with the Pre-Assessment results, the DA service provider shall re-assess DA feasibility. Following validation that IIT methods have confirmed Pre-Assessment prediction results, the DA service provider shall report to EMPCo's Field Steward the results of the IIT surveys and explain any additional validation IIT surveys required for the Indirect Inspection Step and any re-validation of pre-assessment activities required to align the Pre-Assessment predictions with the Indirect Inspection results.

A3.2.4 Defining and Classifying Indication Severity (continued)

Table A3.3: Severity Classification

Tool/ Environment	Minor	Moderate	Severe
Close Interval Survey (aerated, moist soil)	• Small depression in potential profile • "On" and "Off" potentials are both more negative than -850 mV	• Medium depression in potential profile • "On" potentials are more negative than -850 mV • "Off" potentials are not more negative than -600 mV	• Large depression in potential profile • "Off" potentials are not more negative than -600 mV
DCVG Survey (aerated, moist soil)	• < 36% IR • Cathodic both "On" and "Off"	• 36% to 60% IR • Cathodic "On" • Anodic or Neutral "Off"	• > 60% IR • Anodic both "On" and "Off"
AC Current Attenuation survey (Pipeline Current Mapper or C-Scan)	• -9 to -30 mdB/ft	• -31 to -60 mdB/ft	• > -60 mdB/ft

A3.2.5 Deliverables from IIT

The DA service provider shall provide the IIT surveys with a minimum of the following pipeline attributes identified and aligned with the IIT survey data:

- Identification of line segment (map number and segment name from HCA database)
- Station numbers and GPS Coordinates of starting and stopping locations and all identified attributes (from alignment sheets or schematics).
- PI's with stationing and GPS coordinates
- Depth of pipeline (at least every 100 feet)
- Pipeline Markers and Test Leads with stationing and GPS coordinates
- CP Equipment, type and location with stationing and GPS Coordinates
- Land use descriptions
- Valves with stationing and GPS Coordinates
- Roadway descriptions (name and orientation) with stationing and GPS Coordinates
- Topographical features

The DA service provider shall compare the results of the Indirect Inspection results with the Pre-Assessment results and prior maintenance history of the pipeline segment to see if they validate each other. If the assessment results are not consistent with the operating history of the pipeline, the DA service provider must reassess the feasibility of the DA process. The DA service provider shall prepare a summary Indirect Inspection Report for the pipeline segment being assessed with at least the following elements:

- DA Region Report (can be identical to report prepared in A3.1.5 above)
- Indication Classification and Direct Examination proposed sites

Results from the IIT surveys shall be delivered to the Field Steward within 60 days of completion of the field work associated with the IIT. The results shall be complete with dates that inspections were performed, description of the IIT surveys performed and over what stations of the pipeline, the names of personnel who performed the IIT surveys, and summary information. The results can be in either electronic or hard copy format according to the preference of the Field Steward. An Excavation Plan shall be prepared by the DA service provider with a prioritized list of planned Direct Examination excavation sites. HCA maps shall have been delivered to the DA service provider from EMPCo's Field Steward at the time of the Pre-Assessment meeting

Table A3.4: Prioritization of Indirect Inspection Indications

		Close Interval Survey			
		Severe	**Moderate**	**Minor**	**No Indication**
DCVG	Severe	Immediate	Scheduled	Scheduled	Monitored
	Moderate	Immediate	Scheduled	Monitored	No Action
	Minor	Immediate	Scheduled	Monitored	No Action
	No Indication	Immediate	Scheduled	Monitored	No Action
ACCA	Severe	Immediate	Scheduled	Scheduled	Monitored
	Moderate	Immediate	Scheduled	Monitored	No Action
	Minor	Immediate	Scheduled	Monitored	No Action
	No Indication	Immediate	Scheduled	Monitored	No Action

Immediate indications from the above chart shall be treated equivalent to an Immediate Repair indication from an ILI Tool Run as delineated in the EMPCo IMP Manual, whereas Scheduled indications can be treated as a 60 day or 180 day repair in the EMPCo IMP. For example, a point where CIS data indicates a potential of -400 mV off (severe CIS Indication) and ACCA indicates more than -60 mdB/ft (severe ACCA indication) shall be treated as an Immediate Repair Condition, requiring excavation for remediation and/or a pressure reduction of 20% as soon as possible, but not to exceed 5 days from the date that the situation was determined to exist, The DA service provider must immediately contact the DA Field Steward upon discovery of an Immediate Indication from the integration of data from 2 IIT surveys.

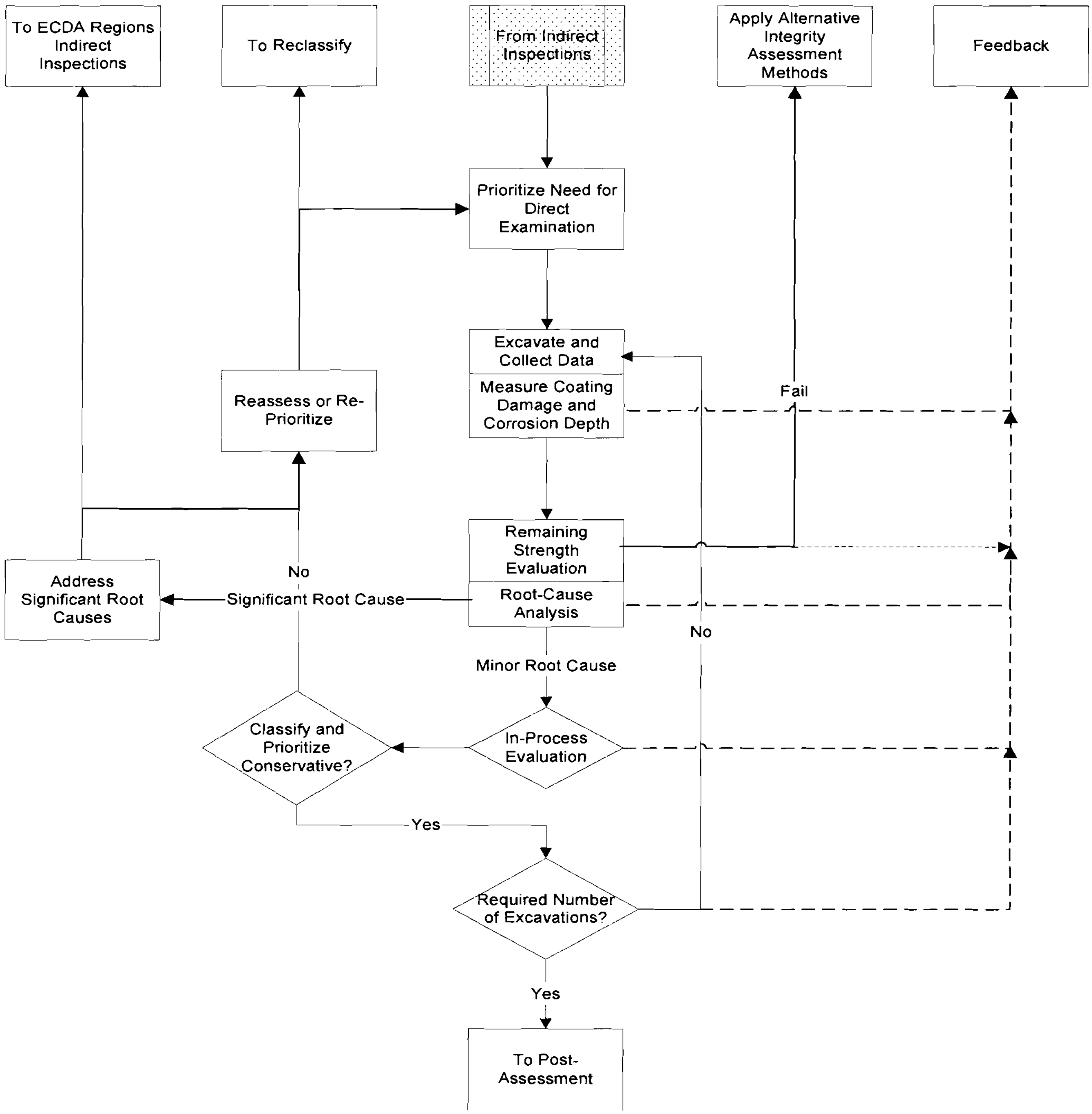
A3.2.6 Excavation Plan

An excavation plan shall be prepared by the DA service provider using the results of individual IIT surveys and an analysis with prioritization performed. A minimum of two excavations is required regardless of the results of the IIT surveys and Pre-Assessment steps. It should be noted that a DA project requiring only two excavations will be rarely encountered. At least three excavations are required for first time DA projects for each pipeline segment assessed with Direct Assessment. The DA Service Provider shall be counseled to err on the conservative side when determining excavation requirements for the Direct Examination step of a DA project.

Direct Assessment proposed excavation sites should be prioritized according to the presence of HCAs with the following priority:

1. Immediate indications inside HCAs
2. Immediate indications outside HCAs
3. Scheduled indications inside HCAs
4. Scheduled indications outside HCAs
5. Monitored indications inside HCAs
6. Monitored indications outside HCAs
7. Null digs inside HCAs
8. Null digs outside HCAs

Figure A3.3: Direct Examination Flow Chart
(continuation of Figure A3.2: Indirect Inspection Flow Chart)



(continued on Figure A3.4: Post Assessment Flow Chart)

A3.3 Direct Examinations

A3.3.1 Objectives:

- Calibrate and validate the prioritization of the IIT indications and their severity
- Collect data to assess corrosion activity at areas where it is most likely
- Measure coating damage, TPD and corrosion defects
- Evaluate remaining strength of the pipeline at any corroded or damaged pipe location
- Perform root cause analysis of corrosion and TPD encountered
- Re-Prioritize remaining indications based on results of Direct Examinations
- Evaluation of the effectiveness if the Indirect Inspection Step to determine if addional IIT surveys are required.
- Evaluation of the DA proces

A3.3.2 Required Excavations

The DA Process requires excavations to expose the pipe surface so that measurements can be made on the pipeline and in the immediate surrounding environment. A minimum of two digs is required regardless of the results of the Indirect Inspection Step and the Pre-Assessment Step. Additional guidelines for excavation are included below. The order in which excavations are made shall be determined in accordance with the results of the IIT and the site of the indication being able to affect a High Consequence Area in accordance with Integrity Management regulations.

Immediate Indications: All Immediate Indications shall be excavated during the Direct Examination Step. If Immediate Indications are re-prioritized to a lesser priority, they may be excavated in accordance with the lower priority.

Scheduled Indications: A minimum of one Scheduled Indication shall be excavated per each DA region. A minimum of two Scheduled Indications shall be excavated per DA region for the first DA project. If 20% or more metal loss is found at a Scheduled Indication, then excavation will continue on the Scheduled Indications in order of priority until at least two Scheduled Indications exhibit less than 20% metal loss. If Scheduled Indications are re-prioritized to Immediate Indications then there shall be at least one more excavation of a Scheduled Indication per each DA region.

Monitored Indications: Monitored Indications are not required to be excavated and can be either monitored or re-prioritized unless a DA region did not have any Immediate or Scheduled Indications, then at least one Monitored Indication shall be excavated for each DA region. At least 2 monitored indications shall be excavated for an initial DA project on that pipeline segment.

Initial DA Projects: Two additional null excavations are required for initial DA projects to assess the effectiveness of the DA process.

A3.3.3 Response to Indications

If Immediate Indications are indicated by the IIT surveys, the Field Steward shall be immediately notified. Excavations for severe anomalies shall be scheduled within 5 working days of the results being received by the Field Steward.

If other significant integrity conditions (other than Third Party Damage and External Corrosion) are found during the Direct Examinations, the DA service provider shall immediately notify the Field Steward. Significant integrity conditions such as significant internal corrosion, ERW seam cracks or Stress Corrosion Cracking found during the excavation process may be cause to invalidate the applicability of the DA process to the pipeline segment under investigation.

A3.3.4 Performing Excavations and Piping Examinations

Procedures for excavations, pipe coating examinations, and pipe surface examinations shall follow the requirements in Appendix 2 of this document and EMPCo's Safe Operating Practices Manual. The results from each excavation shall be recorded on EMPCo's PL-0751 Form: Piping Inspection and Remedial Action Report. The location and size of the excavation shall be expanded in length if the severity of corrosion indications extends beyond the planned excavation area.

A3.3.5 Evaluation of External Corrosion Defects and Third Party Damage

Criteria for repair of defects exposed during the Direct Examination Step shall follow the requirements of the Integrity Management Program Manual as well as EMPCo's Repair and Modifications Manual.

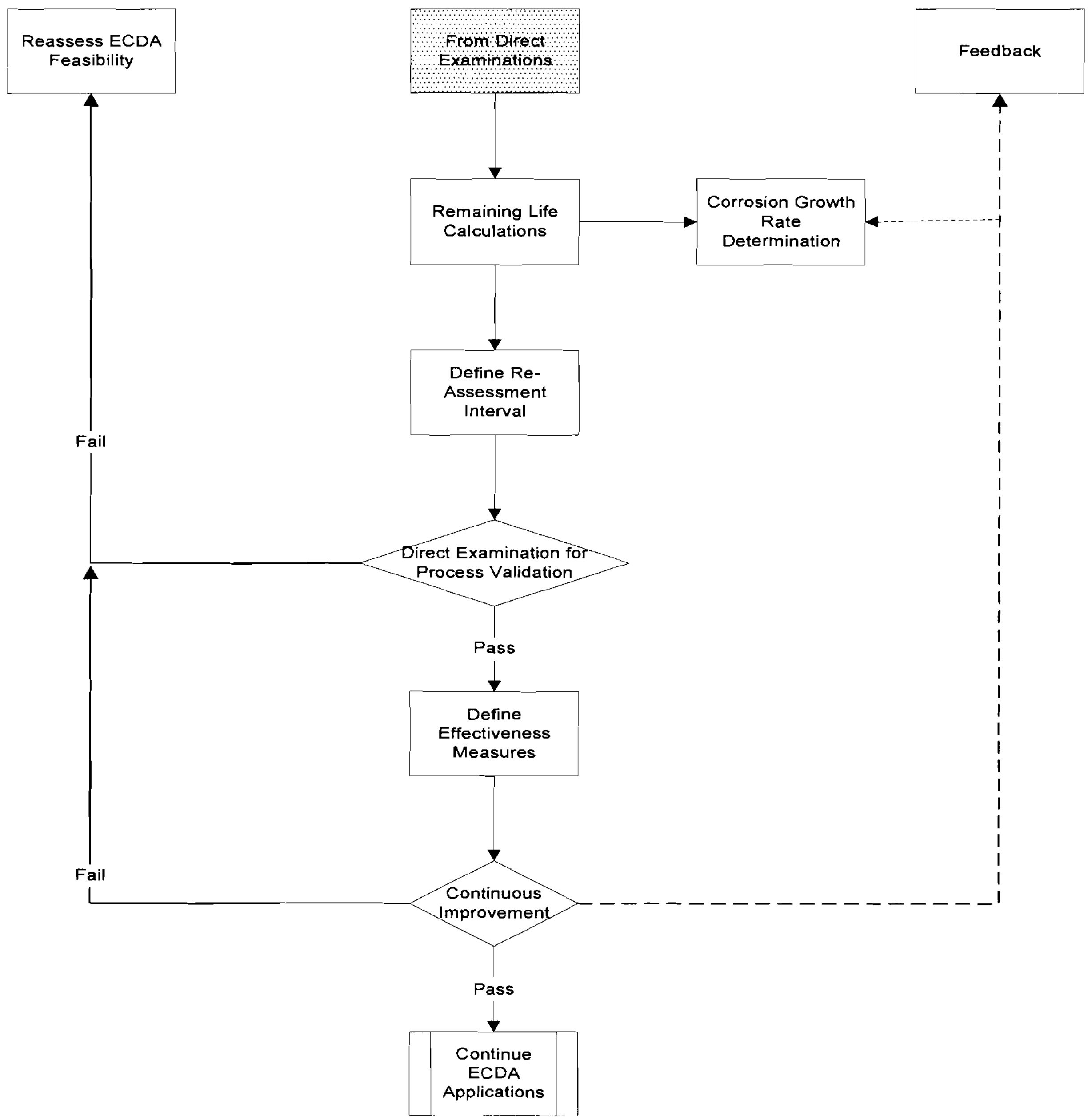
A3.3.6 Root Cause Analysis of External Corrosion Defects and Third Party Damage

The DA Service provider shall identify any existing root cause of significant corrosion activity. Root causes could include inadequate CP current, disbonded coating, interference currents from other facilities, or other causes. If the DA Service provider uncovers a root cause for which the DA process is not well suited, it shall be brought to the attention of the Field Steward at the first opportunity. The Field Steward shall determine, with the aid of the Risk ands Integrity Specialist and/or the Pipeline Integrity Specialist whether the DA process can be applied as a viable integrity Assessment for the pipeline segment under consideration.

A3.3.7 In Process Evaluation

The DA service provider shall perform an evaluation to assess the indirect inspection data and the results of the direct examinations performed to date. The evaluation shall be performed to assess the criteria used to classify the severity of the individual indications and how that criteria matched the pipe conditions found during excavations. If existing corrosion is less severe than prioritized in the IIT surveys, the DA service provider may modify the criteria and reprioritize the remaining indications. For initial DA applications, no reprioritization should be performed that downgrades the prioritization criteria. If existing corrosion is more severe than what was indicated and prioritized from the IIT surveys, then the DA service provider must modify the criteria and re-prioritize the remaining indications. The DA service provider shall immediately notify the Field Steward if re-prioritization must be performed. In addition, the need to perform additional Indirect Inspections shall be considered by the DA service provider and communicated to the Field Steward. If repeated Direct Examinations show corrosion activity that is worse than predicted even after re-classification and prioritization of indications has been performed and criteria adjusted, then the Field Steward must evaluate the viability of DA for the segment being evaluated.

Figure A3.4: Post-Assessment Flow Chart
(continued from Figure A3.3: Direct Examination Flow Chart)



A3.4 Post Assessment

A3.4.1 Objectives:

- Perform remaining life calculations
- Define Re-assessment Intervals
- Assess the overall effectiveness of the DA process
- Provide feedback to improve the DA Process
- Provide a final report of the Direct Assessment Integrity Assessment results

A3.4.2 Remaining Life Calculations

If no significant corrosion defects are found, no remaining life calculations are needed, the remaining life can be considered the same as for a new pipeline, i.e. in excess of forty years. The maximum remaining flaw size must be assumed to be as large as the most severe indication in all locations that have been excavated. If the root cause analysis determines that the most severe location is unique for the DA region, the size of the next most severe location may be used for remaining life calculation with appropriate justification. As an alternative, an operator may substitute a different value based on a statistical or more sophisticated analysis of the excavated severity(s). The corrosion growth rate shall be based upon sound engineering analysis. Measured corrosion rate data for the pipeline and applicable to the DA region under consideration may be used for the corrosion growth rate as demonstrated by the operator. If no measured corrosion rate has been established for the pipeline under consideration, published data should be used in accordance with NACE recommended practices.

Remaining life of the maximum remaining flaw shall be estimated using sound engineering analysis. One method per NACE RP0502-2002 is as follows:

RL = C x SM x [T / GR] where:

RL = Remaining Life (years)

C = Calibration Factor = 0.85 (dimensionless)

SM = Safety Margin = Failure pressure ratio - MAOP ratio (dimensionless)

Failure pressure ratio = Calculated failure pressure/yield pressure (dimensionless)

MAOP ratio = MAOP/yield pressure (dimensionless)
T= Nominal wall thickness (inches)
GR = Growth rate (inches / year)

Note: this method of calculating expected remaining life is based on corrosion that occurs continuously and on typical sizes and geometries of corrosion defects and is considered to be a conservative method. An example published corrosion Growth Rate is shown in table A3.6

Table A3.6: Corrosion Rates vs Soil Resistivity per ASME B31.8S

Corrosion Rate (mils per year)	Soil Resistivity (ohm-cm)
3	> 15,000 + no active corrosion
6	1,000 - 15,000 and/or active corrosion
12	<1,000 (worst case)

When other data is not available, a pitting rate of 16 mils per year is recommended for determining re-inspection intervals per NACE RP0502. This rate represents the upper 80% confidence level of maximum pitting rates for long term (up to 17 year duration) underground corrosion tests of bare steel pipe coupons without CP in a variety of soils including native and nonnative backfill.

An example of estimating corrosion growth rate is as follows: A pipeline under cathodic protection in soil with a resistivity measured between 1500 and 2500 ohm-cm would be assumed to have a worst case corrosion rate at 6 mils per year, unless data collected in the field during the direct assessment phase of a DA project indicated a corrosion growth rate at 4 mils per year in the same DA region. The maximum reassessment interval for each DA region shall be taken as one-half the calculated remaining life. The maximum reassessment interval is limited by regulation and at the time of this document was at a maximum of five years for a hazardous liquid pipeline and at 10 years for a natural gas pipeline. Different DA regions may have different reassessment intervals based on variations in expected growth rates and maximum corrosion defect encountered during the assessment. All scheduled indications should be excavated and repaired prior to the scheduled reassessment date.

A3.4.3 Assessment of Direct Assessment Effectiveness

Direct Assessment is a continuous improvement process through which an operator can identify and address locations at which corrosion activity has occurred, is occurring, or could occur in the future. At least one additional excavation should be performed at a randomly selected location where no indications have been detected with IIT surveys. This "null hypothesis" excavation should yield no indications as a validation that no corrosion or Third Party Damage was found where the process and inspections predicted that no corrosion or TPD would occur. In this way the process is made to prove the positive indication as well as a negative indication. If significant corrosion or TPD is found at the "null hypothesis" site, a process re-evaluation is in order. For the initial DA application to a pipeline segment, two additional excavations are required to be performed in order to further validate that the DA process is applicable and has been implemented successfully. If conditions are found that are more severe than that predicted during the DA process, such that an acceptable reassessment interval is not achieved, the process should be re-evaluated and either repeated or a different assessment method chosen. Sections IV and V of the first part of this document delineate measurements and verification steps as well as continuous improvement items to be implemented as a part of the DA program within EMPCo.

A3.4.4 Feedback

As a continual improvement process, the DA Process is uniquely designed to provide feedback on the performance of both individual assessment evaluations as well as program evaluation. Each flowchart of each step of the process has a feedback loop built into the process such that continuous improvement in each step of the process is facilitated. The DA process is also built to continuously validate each step of the process and recycle steps as appropriate to continuously validate itself during the execution of the process in assessing pipeline integrity. For example, the Indirect Assessment Step provides feedback on performance of the IIT methods selected back to the Pre-Assessment Step in order to further improve IIT selection during the Pre-Assessment Step. The Direct Examination Step provides feedback on performance of the IIT methods and selection of severity criteria back to the Indirect Inspection Step and the Pre-Assessment Step. Post-Assessment also provides feedback on performance of the Direct Examination Step to the Indirect Inspection Step and the Pre-Assessment Step. In this way the process continuously attempts to validate itself as an appropriate integrity assessment method for the pipeline being assessed as well as the DA program overall and it's applicability to assessment of the External Corrosion and Third Party Damage threats to pipeline integrity.

A3.4.5 Final Report

The records and deliverables to be included in the Final Direct Assessment Report by the DA service provider include the following:

- Cover letter to Field Steward requesting approval of DA results
- Pre-Assessment Documentation
  - ➢ Data Elements collected for pre-assessment
  - ➢ Methods and procedures used to integrate the data collected and to determine which IIT methods can and cannot be used
  - ➢ Methods and procedures used to select the IIT.
  - ➢ Characteristics and boundaries of DA regions and the applicable IIT methods chosen for each DA region
- Indirect Inspection Documentation
  - ➢ Geographically referenced locations of the beginning and end points of each DA region and each fixed point used for determining the location of each measurement
  - ➢ Date, weather, and soil conditions under which each IIT survey was performed
  - ➢ IIT survey results in sufficient resolution to identify the location of each indication
  - ➢ Procedures for aligning data from the IIT surveys and expected alignment errors for each IIT
  - ➢ Procedures for defining the criteria to be used in prioritizing the severity of the indications
- Direct Examination Documentation
  - ➢ Complete inspection reports for each excavation performed
  - ➢ Procedures and criteria used to prioritize the IIT survey results
  - ➢ Data collected before, during, and after excavation of IIT indications including:
    - Pipe coating examination results
    - Metal loss anomaly measurements
    - Data used to identify other areas that may be subject to corrosion
    - Data used to estimate corrosion growth rates
    - Results of any root-cause analyses
    - Description and the reason for any re-prioritization performed
    - NDT performed and results of NDT examinations
- Post-Assessment Documentation
  - ➢ Remaining life calculations
  - ➢ Maximum remaining flaw size determinations
  - ➢ Remaining strength evaluation of flaws discovered during DA
  - ➢ Corrosion growth rate determinations
  - ➢ Method of estimating remaining life
  - ➢ Results of remaining life calculations
  - ➢ Reassessment intervals and scheduled activities
  - ➢ Criteria used to assess DA effectiveness and results from assessment
  - ➢ Data from periodic assessments
  - ➢ Recommendations for Scheduled and Monitored indication remediations with timeframes proposed for implementation
  - ➢ Preventive and mitigative measures considered for improvements to pipeline integrity
  - ➢ Feedback items including:
    - Assessment of criteria used in each step of the DA process
    - Modifications of criteria

The Final Report from the DA service provider shall be submitted to the Field Steward for review and approval with comments no later than 90 days after completion of all field work related to the Direct Examinations (other than ongoing repair activities) has been completed. Hard copies or electronic copies of the Final Report shall be provided in accordance with the Field Steward's preference.

A3.4.6: Integration of DA Results Into IMP Activities

After the DA service provider has made delivery of the final report, EMPCO's Risk and Integrity Specialist is charged with integration of the integrity assessment test results with all other integrity data in order to prepare a Repair Plan for any anomalies remaining to be remediated and then perform Preventive and Mitigative Analysis and prepare P&M Activites in accordance with EMPCo's IMP Manual. RIS's are to pay particular attention to P&M Activities to prevent TPD if significant TPD is discovered during the DA of the pipeline segment.